HYDROGEN ENERGY CALIFORNIA PROJECT

Preliminary Staff Assessment,
Draft Environmental Impact Statement

JUNE, 2013
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ENERGY COMMISSION
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Responsible Agencies: U.S. Department of Energy (DOE)
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Title: *Preliminary Staff Assessment and Draft Environmental Impact Statement (PSA/DEIS) for the Hydrogen Energy California's Integrated Gasification Combined Cycle Project, Recovery Act: Demonstration of Integrated Gasification Combined Cycle (IGCC) and of CO_2 Capture and Sequestration technology on a commercial scale, located in Kern County California, near the City of Bakersfield* (DOE/EIS-0431D)

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Abstract: Enclosed for your review and comment is DOE's and the California Energy Commission's joint *Preliminary Staff Assessment/Draft Environmental Impact Statement (PSA/DEIS)*(DOE/EIS-0431D). This document was prepared in accordance with the *National Environmental Policy Act of 1969* (NEPA) and applicable implementing regulations. The CEC must also comply with Title 20, California Code of Regulations section 1701 et seq., and the California Environmental Quality Act (CEQA) (Pub. Resources Code, § 21000 et seq.). The Energy Commission must decide whether to certify the Hydrogen Energy California's Integrated Gasification Combined Cycle Project (HECA); this certification is in lieu of any permits required by state, regional, or local agencies, and federal agencies to the extent permitted by federal law (Pub. Resources Code, § 25500). The PSA/DEIS analyzes the potential environmental impacts of DOE providing financial assistance under the Industrial Carbon Capture and Sequestration (CCS) program to the HECA project.

This PSA/DEIS addresses DOE's proposed action, which is to provide approximately $408 million in financial assistance to HECA, LLC to support the construction and demonstration of the HECA project. The HECA project would demonstrate integrated gasification combined cycle (IGCC) and carbon capture technology on a commercial scale turning a fuel blend consisting of 75% western sub-bituminous coal and 25% petroleum coke (petcoke) into a synthesis gas (syngas) in a new power plant consisting of a single gasifier with gas cleanup systems, a gas combustion turbine, a heat recovery steam generator, a steam turbine, and associated facilities capable of generating 405 MW gross power. Because of its multiple production capabilities, the plant is referred to as a poly-generation (or polygen) plant designed so that it could sell urea, ammonia, and perhaps other nitrogenous compounds.

DOE invites interested parties to comment on this draft EIS during the 45-day comment period that will begin when the U.S. Environmental Protection Agency (EPA) publishes a notice of availability in the *Federal Register*.

Availability: DOE encourages public participation in the NEPA review process. A Notice of Availability will be placed in the Bakersfield Californian. This draft PSA/DEIS is also being made available for public review on DOE's National Energy Technology Laboratory web site, *http://www.netl.doe.gov/publications/others/nepa/ea.html, and DOE's NEPA web site at http://nepa.energy.gov/DOE_NEPA_documents.html* and posted on the California Energy Commission Docket at, *http://www.energy.ca.gov/sitingcases/hydrogen_energy/*

HYDROGEN ENERGY CALIFORNIA
(08-AFC-08A)
PRELIMINARY STAFF ASSESSMENT AND
DRAFT ENVIRONMENTAL IMPACT STATEMENT

Environmental Assessment

Engineering Assessment

EXECUTIVE SUMMARY

John Heiser

INTRODUCTION

This Preliminary Staff Assessment and Draft Environmental Impact Statement (PSA/DEIS) contains the California Energy Commission (Energy Commission) staff's and the US Department of Energy's (DOE) independent evaluation of Hydrogen Energy California, LLC's (applicant) Amended Application for Certification (08-AFC-8A) for the proposed Hydrogen Energy California project (HECA).

Energy Commission staff has completed an independent assessment under the California Environmental Quality Act (CEQA) and has revealed significant, and for the most part, unresolved issues. The issues are summarized as follows and discussed further in the Executive Summary and in detail in each related section of the PSA/DEIS.

DOE has completed its assessment pursuant to the National Environmental Policy Act. In accordance with Council on Environmental Quality implementing regulations (40 CFR 1500 thru 1508) and DOE's implementing procedures (10 CFR 1021), DOE has identified and evaluated the potential environmental impacts of the Proposed Action (providing financial assistance for the construction and operation of the applicant's project) and the alternatives. The PSA/DEIS describes the affected environment and the environmental consequences of the alternatives among various resource areas. DOE is also using the PSA/DEIS to fulfill certain responsibilities for documenting wetlands and floodplain impacts (10 CFR 1022), conformity with air quality standards (40 CFR Part 93), and consulting with expert agencies and tribes as required by the National Historic Preservation Act (Section 106), the Endangered Species Act (Section 7), and the Native American Graves Protection and Repatriation Act.

Air Quality

The San Joaquin Valley Air Pollution Control District has completed the Preliminary Determination of Compliance (PDOC) for HECA, and the District's analysis concluded that the HECA facility as proposed would comply with all applicable laws, ordinances, regulations and standards and would not create a health risk to the residents of the Valley. The PDOC contains upwards of 1,000 conditions applicable to the project. The District has approved two mitigation agreements with HECA to receive funds in the amount of $8,747,160 for the purpose of mitigating air quality impacts of the facility.

Greenhouse Gas Emissions

The applicant has described the facility's expected electrical capacity and hours of operation using more than one potential operating profile. Different operating profiles may need to be evaluated to determine which set of conditions represent actual operations and worst case impacts. Some operating profiles may result in the facility not complying with certain regulatory requirements. The California Air Resources Board (ARB) currently has not finalized regulations for geologic sequestration under the cap and trade program. If a methodology is not in place once the project is operational, it would have to purchase allowances or offsets for all CO_2 that HECA would sequester in addition to the direct CO_2 emissions. Once the methodology is in place, the project would still be required to purchase allowances for the CO_2 it is unable to sequester.

Biological Resources

The proposed HECA project would result in a significant, unavoidable impact to Blunt Nosed Leopard Lizard, a California Fully Protected species. During May 2013, the applicant submitted a Section 2081 Incidental Take Permit application for project impacts to state-listed wildlife species for which the applicant would be seeking incidental take coverage which staff has preliminarily reviewed. The U.S. Fish and Wildlife Service (Service) is reviewing the Biological Assessment that DOE sent to the Service on March 1, 2013. This is the process by which DOE complies with the consultation requirements of Section 7 of the Endangered Species Act.

Cultural Resources

Staff is still awaiting additional information from the applicant and has not reached any final conclusions regarding impacts to cultural resources. Approximately 75 percent of the HECA project components are located in areas considered sensitive for the presence of buried archaeological sites. There are potentially 21 known archaeological resources that would require mitigation along the proposed process water pipeline. At least five archaeological resources at the Enhanced Oil Recovery (EOR) site have been identified so far that would need to be mitigated. Additional sensitive resources may be identified as additional information is submitted prior to the publication of the FSA/FEIS.

Environmental Justice

Socioeconomics Figure 1 identifies an environmental justice population in the buffer area surrounding HECA and associated Elk Hills Oil Field EOR operation. Currently, several members of the technical staff have identified significant impacts from the construction and operation of the proposed HECA project, including the associated EOR operation. Staff does not have the necessary information to determine if these impacts can be mitigated below a significant level. If not, some or all of these impacts could have adverse or disproportionate impacts on an environmental justice population. Staff has requested the information they need to complete their impact analysis for inclusion in the FSA/FEIS.

HECA may result in an increased use of the Wasco coal transloading facility which could result in impacts related to air quality, public health, and traffic and transportation, among others. The potential need for expansion and improvements of the coal transloading facility near Wasco was not analyzed in the PSA/DEIS. Staff will be analyzing these potential impacts in the FSA/FEIS. **Socioeconomic Table 2** shows that on April 1, 2010 there was an 86 percent minority population in Wasco. Staff will assess whether there is an environmental justice population in the immediate vicinity of the transloading facility that could be adversely or disproportionately impacted. Staff will provide updated information in the FSA/FEIS

Land Use

HECA would result in a loss of 495 acres (for project site and rail spur) of Prime Farmland and Farmland of Statewide Importance. The project would require cancellation of Williamson-Act contracts for the facility site and lands associated with the rail spur. A Williamson Act contract cancellation request was scheduled for a public hearing with the Kern County Planning Commission on June 13, 2013. A continuation of this request has been re-scheduled for June 27, 2013 for Kern County Planning Commission consideration. Final determination of the cancellation request is to be made by the Kern County Board of Supervisors sometime thereafter. The proposed rail spur will require both private and public rail crossings to ensure that it will not divide the community, potentially resulting in a significant impact. Staff is waiting for additional information from the applicant.

Traffic and Transportation

HECA would result in a substantial increase in number of vehicles on local roads during construction and operation. Specifically, during construction the project would add 615 construction worker trips, 25 truck deliveries, and 80 trips for soil deliveries peak daily roundtrips.

Two alternatives are under consideration for transporting coal to the HECA facility: 1) constructing a rail spur or; 2) using trucks to deliver coal after it has been transported by rail from New Mexico. For the rail spur option (listed as Alternative 1 in the amended AFC), an approximately 5-mile-long new industrial railroad spur would be constructed to connect the HECA facility to the existing San Joaquin Valley Railroad (SJVRR) Buttonwillow railroad line. This railroad spur would also be used to transport some HECA products to market. For the no rail spur option (listed as Alternative 2 in the amended AFC), an approximately 27-mile-long truck transport route would be used via existing roads to transport the coal from an existing coal trans-loading facility located northeast of the HECA project site. The applicant is currently requesting that both options be certified.

During operation with the rail spur, the project would add 51 operations and maintenance, 71 process materials and byproducts, and 55 feedstock materials delivery peak daily roundtrips. Without the rail spur, the project operation would add 51 operations and maintenance, 133 process materials and byproducts, and up to 400 feedstock materials delivery daily roundtrips.

Visual Impacts

Staff's preliminary determination of HECA would likely result in unmitigable significant impacts to visual resources.

Water Supply

The applicant has estimated that the HECA project will use 7,500 acre feet of groundwater per year. Applicant believes that the water is high in total dissolved solids (TDS) and therefore acceptable for process use in accordance with SWRCB Resolution

75-58. However local farmers argue the groundwater has greater beneficial uses for irrigation of pistachio crops. Buena Vista Water Storage District (BVWSD) developed a Brackish Groundwater Remediation Plan, which indicates the HECA project could play a large role in its implementation. Staff has been unable to confirm that the plan for HECA to use this groundwater has any beneficial effect on water quality in the aquifer. In fact staff believes, given current data, that there could be a significant impact on water quality that could affect other users. In addition, staff has concluded that the planned well field extraction rate (7,500 AF/yr) may exceed the annual storage increase characterized by historical water level trends. This would be a significant impact for which no mitigation has been identified. The applicant and BVWSD have indicated there is additional information staff has not considered in the analysis. Staff has repeatedly requested this information and to date has not received it.

Staff is in the process of investigating the feasibility of dry cooling the facility, which would reduce project water demand by approximately 90 percent of the proposed amount and could reduce water costs by approximately $76,000,000 over the 25-year life of the project. Such an analysis could mitigate potential impacts from overdraft and to water quality.

Waste Management

A major byproduct of the HECA project will be gasification solids (coal/petcoke/limestone ash and slag). The applicant is researching possible ash and slag markets, including for use in asphalt, sandblasting, or other industrial uses. If no market can be found, however, then it will have to be landfilled, which could cause Kern County to exceed CalRecycle's acceptable waste/recycle ratio. Kern County has requested a modification from CalRecycle that would exempt these wastes from the requirement, but so far CalRecycle has not responded. It would be helpful to get CalRecycle to weigh in on whether it would grant the modification prior to the Final Staff Assessment. The applicant is assessing the economics and logistics of train transportation of ash and slag to out-of-state landfills. It is unclear how this would affect Kern County's CalRecycle compliance. Additionally, as a result of previous site activities, recent soil sampling and analytical testing indicated elevated concentrations of petroleum hydrocarbons and other contaminants. Prior to publication of the FSA/FEIS staff recommends that the project owner develop a Soils Management Plan (SMP) to describe procedures to be followed during soil disturbance so workers can be protected from soil contamination that may be encountered. Staff proposes Condition of Certification **WASTE-1** to ensure the applicant has procedures in place to properly handle and dispose of contaminated soil.

PREPARATION AND USE OF A JOINT-ENVIRONMENTAL DOCUMENT

The Energy Commission has exclusive permitting jurisdiction for the siting of thermal power plants of 50 megawatts (MW) or more and their related facilities in California. The Energy Commission also has responsibility for ensuring compliance with the California Environmental Quality Act (CEQA) through the administration of its certified regulatory program and as the lead agency under CEQA. Through the Energy Commission's certified regulatory program, this document is functionally equivalent to an

Environmental Impact Report (EIR), and examines engineering, environmental, public health and safety aspects of the proposed HECA project, based on the information provided by the applicant and additional independent information available from other sources at the time the PSA/DEIS was prepared.

The U.S. Department of Energy (DOE) proposes to provide financial assistance to Hydrogen Energy California, LLC to design, construct and demonstrate the HECA. DOE selected HECA for funding through a competitive process under the Clean Coal Power Initiative program (CCPI), round three. Because DOE proposes to award funding to the HECA project, DOE's proposed action is subject to the National Environmental Policy Act (NEPA) process which, in this case, requires preparation of a Draft Environmental Impact Statement (DEIS) followed by a Final Environmental Impact Statement (FEIS).

The Energy Commission staff and the DOE have cooperated to complete an assessment of the project's engineering design and identify the potential impacts on the environment, the public's health and safety, as well as determine whether the project conforms to all applicable laws, ordinances, regulations and standards (LORS). Additionally, upon identifying any potentially significant environmental impacts, Energy Commission staff recommends mitigation measures in the form of conditions of certification for construction, operation and eventual closure of the project, in order to comply with CEQA.

This PSA/DEIS is not a decision document for DOE or the Energy Commission, nor does it contain findings of the Energy Commission related to environmental impacts or the project's compliance with local/state/federal legal requirements. This document serves as a precursor to the Final Staff Assessment/Final Environmental Impact Statement (FSA/FEIS).

Energy Commission and DOE staff will hold a joint PSA/DEIS public workshop to receive public and agency comment on the PSA/DEIS after its publication. The workshop is used to receive comments from individuals and organizations, to identify and resolve areas of disagreement and to discuss additional informational requirements. In addition, DOE and Commission staff will accept comments on the PSA/DEIS for at least 45 days after publication of the U.S. Environmental Protection Agency's notice of availability of the PSA/DEIS.

After close of the comment period on this PSA/DEIS, DOE and Energy Commission staff will prepare and publish the FSA/FEIS, the FSA portion of which will serve as Energy Commission staff's formal testimony in evidentiary hearings to be held by the Energy Commission Committee assigned to hear this case. The Committee will hold evidentiary hearings and will consider the recommendations presented by the staff, applicant, intervenors, government agencies, and the public, prior to issuing a proposed decision. Following a 30-day comment period and a public hearing(s), the full Energy Commission will make a final decision. The FSA/FEIS will also be used by the DOE to inform its decision on whether to award funding to Hydrogen Energy California, LLC. DOE's decision will be announced in a Record of Decision.

PROJECT HISTORY

The original Application for Certification (08-AFC-8) was filed with the Energy Commission on July 31, 2008; and a Revised AFC was submitted in 2009 to reflect a change of the project site to an alternative location. In 2011, Hydrogen Energy California, LLC was acquired from the previous owners by SCS Energy California, LLC. On May 2, 2012, SCS Energy, LLC, submitted an Amended Application for Certification (08-AFC-8A) reflecting several changes to the original project design.

The new Amended AFC has been assigned a separate distinguishing docket number, 08-AFC-8A. The Amended AFC for the project supersedes and replaces all previous filings from the earlier proceeding (08-AFC-8).

PROJECT LOCATION

The proposed project would be located on a 453 acre site (currently used for agricultural production of alfalfa, cotton, and onions). The applicant has an option (contract) to purchase an additional 653 acres adjacent to the project site, which would allow for controlled access and land use. The project site would be located in an unincorporated portion of Kern County, approximately 7 miles west of the western border of the city of Bakersfield. The proposed site is 1.5 miles northwest of the unincorporated community of Tupman, and approximately 4 miles southeast of the unincorporated community of Buttonwillow. Refer to **Project Description Figure 1** for a map showing the location of the project. An irrigation canal (California State Water Aqueduct) lies to the south, and the Elk Hills Oil Field is located approximately 3 miles southwest of the project site. The project would have a 13-mile long natural gas pipeline, 1-mile long potable water pipeline, 2-mile long transmission line interconnecting to a new Pacific Gas and Electric (PG&E) switching station east of the project site, approximately 3-mile long CO_2 pipeline, a 15-mile long process water pipeline and a 5-mile long rail spur.

The western border of the Tule Elk State Natural Reserve (California State Park) is located approximately 1,700 feet to the east of the project site. The nearest residential dwellings are located approximately 370 feet to the northwest, 1,400 feet to the east, 3,300 feet to the southeast of the proposed project site, and 4,000 feet to the north.

PROJECT DESCRIPTION

HECA would use an integrated gasification, combined-cycle power system to produce and sell electricity, carbon dioxide, and fertilizer. Coal and petroleum coke (a refinery byproduct), would be gasified with oxygen (obtained from the air separation unit - ASU) to produce synthesis gas (syngas). The ratio of coal and petroleum coke used would be approximately 75 percent and 25 percent, respectively. The syngas would be cleaned via scrubbers and absorbers to filter out chlorides, sulfur, mercury, particulates, and impurities. Lastly, the syngas would be stripped of carbon dioxide, leaving a hydrogen-rich gas.

The hydrogen rich gas would either be combined with air and used as fuel in a combustion turbine combined cycle facility to produce electricity (similar to a natural gas fired combined cycle) or sent to an integrated manufacturing complex to produce over 1,000,000 tons per year of nitrogen-based fertilizer. The manufacturing complex would manufacture anhydrous ammonia and nitric acid to produce urea ammonium nitrate (UAN) and urea pastilles. The anhydrous ammonia and nitric acid would only be intermediate products used to produce fertilizers and would not be sold as stand-alone products.

The project would capture up to 90 percent of the carbon dioxide in the syngas stream, which would then be piped a little over 3 miles to the Elk Hills Oil Field, where it would be used by Occidental of Elk Hills, Inc. (OEHI) for enhanced oil recovery (EOR). This use of captured CO_2 could result in the eventual sequestration of approximately 2.6 million tons of CO_2 per year. Some of the captured CO_2 and nitrogen from the air separation unit would be used to manufacture urea fertilizer and other nitrogenous compounds. While OEHI has stated that it can use as much carbon dioxide as HECA can produce, the stated lifespan of the OEHI operation (20 years) is shorter than the length of time HECA proposes to operate (25 years).

The project proposes to generate between 405 and 431 MW gross or an average of 416MW gross electrical power and between 151 to 266 MW net after accounting for onsite auxiliary power loads. The lower values apply during the periods of maximum fertilizer production and the higher values apply during periods of maximum electricity production. When considering the air separation unit and the electricity used by OEHI during enhanced oil recovery operations, which are both part of the project as described by the applicant, the net electricity generation available to California consumers drops to 52.5 MW of new electrical capacity added to the grid during periods of maximum electricity production. The project would be a net consumer of 61.8 MW from the grid during periods of maximum fertilizer production. These net power values include all project-wide power generation and power consumption sources, including the power consumption of the third-party owned air separation unit and the power consumption required by OEHI for CO_2 compression/injection/recovery/re-injection for EOR and, ultimately, carbon sequestration.

The coal would be transported from New Mexico via rail. The applicant has requested certification of two options for final transport to the project site. One option would be to construct a 5-mile long rail spur so that trains could go directly to the project site. The other option would be to offload the coal at the Wasco Transloading Facility into trucks for 400 round trips each day for the final 27 miles to the project site. In either case, the petroleum coke would be trucked in from the Santa Maria refinery or other refineries located in Southern California.

In addition to electricity and CO_2, other produced products would include degassed liquid sulfur, gasification solids and nitrogen-based fertilizers. HECA is expected to generate a maximum of 850 tons per day of gasification solids, 200 tons per day of sulfur, 2,800 tons per day of UAN and 1,670 tons per day of urea pastilles. The actual production rates of these intermediate and final products are likely to vary as market conditions dictate.

The gasification solids would accumulate onsite (up to 7 days worth could be stored on site) and made available for appropriate recycling or beneficial use into roofing shingle aggregate and concrete pozzolanic admixtures. If these options are not available, HECA would dispose of these solids in accordance with applicable laws. The sulfur in the feed stocks would be removed and converted to a salable product, which would be transported offsite by truck or rail. The UAN and urea pastilles would also be exported offsite by truck or rail.

A portion of the hydrogen-rich fuel would be used as a feedstock for the ammonia synthesis unit, which would have a capacity of 2,000 tons per day of ammonia. The ammonia would be used as an intermediate for the production of urea for sale. The project's urea production unit would use pastillation technology, which converts urea melt into high quality urea pastilles (small solid pellets). The unit would have a capacity of about 1,670 tons per day.

The applicant proposes to use up to 7,500 acre feet per year of groundwater purchased from the Buena Vista Water Storage District, which is significantly more water per megawatt than other projects recently licensed by the Energy Commission. While the applicant and district refer to this water as brackish, there is evidence that it could be used for other more beneficial purposes.

For more detailed information about the project and its components, please see **Project Description**.

CUMULATIVE EFFECTS

Staff conducted an extensive search of past, present, and reasonably foreseeable "probable" future projects (see **Cumulative Project List Table 14** in the **Socioeconomics** section). Staff reviewed project tracking information and available environmental reports and notices through various resources, including websites of local, regional and state jurisdictions. Additionally, staff queried project managers from various California public agencies to compile a comprehensive list of past, present and probable future projects that resulted in its list of Cumulative Projects. **Table 1** below presents a master list of the projects considered part of the HECA cumulative setting.

CEQA Guidelines define cumulative impacts as "two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts." (Cal. Code Regs., tit. 14, § 15355.) The Guidelines continue: (a) "[t]he individual effects may be changes resulting from a single project or a number of separate projects" and (b) "[t]he cumulative impact from several projects is the change in the environment which results from the incremental impact of the project when added to other closely related past, present, and reasonably foreseeable probable future projects. Cumulative impacts can result from individually minor but collectively significant projects taking place over a period of time." (*Ibid*.)

Accordingly, staff in each technical section of this PSA determined which of the projects from the Cumulative Projects list could create impacts specific to their technical area.

Using unique sets of criteria specific to each area, staff then evaluated whether the cumulative effects were significant, and if so, whether the project's contribution to that combined effect would be "cumulatively considerable". Therefore, this PSA/DEIS will identify and analyze the impacts of all aspects and phases of HECA, including the combined effect the proposed project will have in conjunction with other projects.

Table 1 -- HECA Master List of Cumulative Projects

Project Name	Location	Description
Abajo Transmission	Kern County	Installation of 18-inch diameter pipeline along Abajo Avenue connecting Sage Land and Santa Lucia water tanks.
Barren Ridge Transmission	Kern County; Los Angeles County	Expansion of Barren Ridge Switching Station; and construction of Haskell Canyon Switching Station; construction of 230 kV transmission lines and reconductoring of existing lines.
Berry Petroleum Steam Injection	Kern County	Construction of cyclic steam injection facilities for enhanced oil recovery.
Biodiesel Refinery	City of Fresno	Three phase construction of industrial biodiesel refining facility.
Borax Co-gen Plant Replacement	Kern County	Construct replacement co-generation plant with two natural-gas-fired turbine generators and steam recovery system.
California High Speed Rail	Fresno County; Kern County; Los Angeles County	Construction of dedicated, electrified high-speed rail system. If developed, Merced to Palmdale sections may utilize area labor.
Calnev Pipeline Expansion	San Bernardino County	Construction of a new 233-mile 16-inch diameter pipeline.
Crystal Geyser Bottling Plant	Inyo County	Construct water-bottling facility with associated warehouse and 8.3-acre solar photovoltaic power array.
Fremont Valley Preservation	Kern County	Construction of tertiary wastewater treatment and disinfection facility.
Fresno Tertiary Water Treatment	City of Fresno	Construct tertiary wastewater treatment and disinfection facility.
Lehigh Alternative Fuels	Kern County	Install equipment necessary to use alternative fuels to provide heat for cement production.
Liberty Energy Center	Kern County	Construct 19.5-megawatt gasification facility to supplement existing composting operation.
Northern Area Water	Kern County	Convert 18-miles of earthen canals to 25-miles of pipeline in Buttonwillow Service Area.
Red Rock Bridge Replacement	Kern County	Replace existing bridge on SR 14 at Red Rock Canyon Wash.
Sierra View Hospital Laboratory	City of Porterville	Construct new hospital laboratory facility.
Tulare County Sherriff Detention Facility	Tulare County	Construct new Tulare County detention facility.

Sources: Fresno County 2012, Kern County 2012b, Kern County 2012c, Kern County 2012d, OPR 2012.

In addition to the projects listed above, staff identified 132 solar photovoltaic power projects and 11 wind power projects that are planned, proposed, or under development in the defined labor market area for staff's socioeconomics analysis. Over half of the solar projects are proposed in Kern County, while the remaining projects are primarily in Fresno County. The photovoltaic projects range in size from one MW or less, to over 1,000 MW, in the case of the Kern Solar Ranch project. The majority of the proposed wind power projects are located in eastern Kern County. They range in size from 40 to 750 MW.

PUBLIC AND AGENCY COORDINATION AND OUTREACH EFFORTS

Energy Commission certification is in lieu of any permit required by state, regional, or local agencies, and federal agencies to the extent permitted by federal law (Pub. Resources Code, §25500). However, the Energy Commission seeks comments from and works closely with other regulatory agencies that administer LORS that may be applicable to proposed projects. These agencies may include, but are not limited to, the U.S. Environmental Protection Agency, U.S. Fish and Wildlife Service, U.S. Army Corps of Engineers, State Water Resources Control Board, Central Valley Water Quality Control Board, California Department of Fish and Wildlife, the California Air Resources Board, California Public Utilities Commission, California Department of Conservation (including the Division of Oil, Gas, and Geothermal Resources), California Department of Parks and Recreation (including the Office of Historic Preservation), California Department of Toxic Substances Control, the San Joaquin Valley Air Pollution Control District, Buena Vista Water Storage District, and Kern County.

On May 15, 2012, the Energy Commission staff sent a notice of receipt and a copy of the HECA Amended Application for Certification to a comprehensive list of all local, state, and federal agencies that administer LORS applicable to the project, as well as to other agencies that may have an interest in the proposed project and public libraries. Additionally, the notice of receipt of the Amended AFC was sent to property owners within 1,000 feet of the proposed project and those located within 500 feet of the linear facilities. In addition to providing notice of receipt of the AFC, the notices provided a brief description of the project, discussion of the Energy Commission's siting certification process, and information on how agencies and the public can comment and participate in the proceeding. Staff continues to seek cooperation and comments from regulatory agencies that administer LORS that are applicable to the proposed project as well as comments from the public. Staff also mailed notices on May 15, 2012, informing elected officials of the Commission's receipt and availability of the application 08-AFC-8A. Each notice contained a link to the Commission-maintained HECA project website (http://www.energy.ca.gov/sitingcases/hydrogen_energy/index.html).

On June 19, 2012 the U.S. Department of Energy placed in the *Federal Register* an Amended Notice of Intent Modifying the Scope of the Environmental Impact Statement for the Hydrogen Energy California's Integrated Gasification Combined Cycle Project.

LIBRARIES

On May 11, 2012, (08-AFC-8A) the Energy Commission staff sent the HECA Amended AFC to libraries in the city of Taft, Tehachapi, Boron, Bakersfield, and Buttonwillow. In addition, the Amended AFC was also sent to state libraries in Eureka, Fresno, Los Angeles, Sacramento, San Diego, and San Francisco.

PUBLIC WORKSHOPS

Energy Commission staff conducted several public workshops to facilitate public, agency, and intervenor participation. Furthermore, these workshops allowed a transparent and comprehensive discussion of several technical issues related to the proposed project and allowed for further staff, agency, and public understanding. The Energy Commission issued notices for all these workshops at least 10 days prior to each meeting. These workshops were conducted on the following dates:

On June 20, 2012, Energy Commission staff facilitated a workshop on the Amended AFC (08-AFC-8A), data requests, and the revised Monitoring, Reporting and Verification Plan (MRVP). The purpose of the workshop was to allow staff, the applicant, intervenors, interested agencies, and the public to discuss several technical disciplines related to the HECA Amended AFC, including but not limited to the project description, air quality, carbon capture and storage, coordination between local, state and federal agencies, traffic and transportation, water resources and other topics as needed.

On July 12, 2012, DOE and CEC held a joint publicly noticed meeting at the Elk Hills Elementary School, 501 Kern Street, Tupman, CA 93276. For the Energy Commission, this meeting constituted its Site Visit and Informational Hearing, which provided an opportunity for members of the community in the project vicinity to obtain information about the project and included a site visit and brief presentation at the proposed project site.

On September 27, 2012, staff conducted a publicly noticed data response workshop in Sacramento and discussed the topics of air quality, greenhouse gas, carbon capture and storage, land use, biology, cultural resources, socioeconomics, traffic and transportation, public health and safety, visual resources, public health, hazardous materials, hazardous waste, and soil and water resources. Participating in the workshop were the applicant, US DOE, California Department of Fish and Wildlife, U.S. Fish and Wildlife Service, Sierra Club, and the public.

On November 7, 2012, staff conducted a publicly noticed data response workshop in Bakersfield with the applicant, intervenors and public with discussions on air quality, greenhouse gas, carbon capture and storage, land use, biology, public health and safety and hazardous materials. Participating agencies in the workshop included the California Department of Fish and Wildlife, California Department of Conservation - Division of Oil, Gas, and Geothermal Resources (DOGGR), and Kern County.

On February 20, 2013, Energy Commission staff conducted a water supply issues resolution workshop at the California Energy Commission office in Sacramento, California. The applicant, Buena Vista Water Storage District staff, intervenors, interested agencies, and public where in attendance.

After the PSA/DEIS has been published, PSA/DEIS Workshops (CEQA)/Public Meetings (NEPA) will be held in Buttonwillow (Kern County, California).

CONSULTATION WITH LOCAL NATIVE AMERICAN COMMUNITIES

The following is intended as a narrative record of Native American consultation for the project. Updates will be added as appropriate and dated. A separate list of participants in the Native American consultation process is kept by the Energy Commission team and U.S. Department of Energy.

Consultation with local Native American communities regarding the proposed HECA project was initiated by three entities: URS Corporation (consultant to the applicant), the U.S. Department of Energy (DOE), and Energy Commission staff.

URS contacted the California Native American Heritage Commission on four occasions from 2008 through 2009, requesting a records search of the Sacred Lands File, and a list of local Native American contacts (individuals and/or organizations) that might have knowledge of cultural resources within the project area of analysis. The Native American Heritage Commission provided lists of individuals and organizations that might have knowledge of cultural resources in the project area of analysis. URS sent letters to the listed contacts; the letters described the proposed project and contained a map depicting the proposed project. Letters were sent to the identified parties on March 14, 2008; June 24, 2008; and April 1, 2009. The letters inquired whether the recipients had any concerns regarding the proposed project or wished to provide input regarding cultural resources in the project area of analysis. URS also corresponded with Native American contacts by telephone between 2008 and 2010. Native American input consisted of recommendations for cultural resources monitoring during construction and preparation of a monitoring plan and burial agreement.

On May 10, 2012, DOE mailed consultation letters to three federally recognized Indian tribes in partial fulfillment of its obligations to consult with Indian tribes under Section 106 of the National Historic Preservation Act, among other federal laws, orders, regulations, and guidelines. These tribes were the Tejon Indian Tribe, Santa Rosa Rancheria of Tachi Yokuts, and Tule River Indian Tribe. The Tejon Indian Tribe responded by letter on June 5, 2012, indicating that it had no knowledge of specific cultural resources in the project area nor any conflict with the proposed project. Tejon Indian Tribe later indicated that it was interested in more information about the proposed project (see below).

Energy Commission staff consulted with Native American tribes and individuals regarding the proposed HECA project. Staff obtained a list of local Native American contacts from the State of California's Native American Heritage Commission on June 13, 2012. Staff mailed letters to these 10 contacts (representing eight tribes and Native American organizations) on June 21, 2012. The letters briefly described the proposed project, outlined the Energy Commission's siting review process, and requested comments and information concerning cultural resources. On July 17, 2012, staff met with Dr. Donna Begay, then-tribal chairwoman of the Tubatalabals of Kern Valley, to discuss tribal concerns with the proposed project. Staff also had telephone conversations with several Native Americans and DOE staff.

Correspondence between staff, tribes, and DOE culminated in a September 26, 2012 meeting to examine the enhanced oil recovery area in Elk Hills. The meeting was attended by Energy Commission staff, members of the Tejon Indian Tribe, DOE personnel, and personnel from Occidental of Elk Hills. The purpose of the meeting was to acquaint the Tejon Indian Tribe with the setting of the proposed enhanced oil recovery facilities, the proposed HECA project as a whole, and discuss tribal concerns. Although the Tejon Indian Tribe did not share information about specific cultural resources in the project area of analysis, the tribe indicated that it is concerned about the proposed project's potential to damage Native American archaeological sites and human remains. All parties present discussed the level of effort needed to identify cultural resources in the proposed Occidental of Elk Hills enhanced oil recovery area, and the Tejon Indian Tribe requested information about how it can continue to participate in the siting review process.

During the weeks of October 8 and 15, 2012, staff mailed packets of information to the tribes and individuals that asked to participate further in the siting review process. Packets were sent to the Tejon Indian Tribe, Santa Rosa Rancheria of Tachi Yokuts, Kitanemuk & Yowlumne Tejon Indians, and Ron Wermuth. These packets contained information on how to participate in the siting process, project descriptions and associated maps.

DOE had a follow-up telephone conversation with the Tejon Indian Tribe on October 3, 2012, during which the tribe stated that it would be requesting confidential archaeological resource maps from the Energy Commission. Staff has not yet received the specific requests.

Participants in the meetings are on file with the Energy Commission and DOE.

ENERGY COMMISSION'S PUBLIC ADVISER'S OFFICE

The Energy Commission's outreach program is also facilitated by the Public Adviser's Office (PAO), which conducts an ongoing, consistent outreach process apart from the efforts of the applicant or other parties. The PAO ensures full and adequate public participation in the HECA project through a variety of activities, including:

- advising interested groups and the public about how to participate;
- requesting that organizations post public service announcements;
- distributing notices about the Energy Commission's receipt of the HECA Amended Application for Certification (AFC); and

- placing advertisements in local newspapers and distributing bilingual notices regarding the Public Site Visit and Informational Hearing/DOE Scoping Meeting held on July 12, 2012 at the Elk Hills School in Tupman (Kern County), California.

RESPONSE TO COMMENTS

Energy Commission staff endeavored to respond to all comments pertaining to the proposed project received to date. As this document was being finalized for publication, however, it could not be continually updated to respond to comments still coming in. Therefore, any comments already made but not addressed in this document will be addressed in the appropriate technical section in the FSA/FEIS. All comments received in response to DOE's Notice of Intent have been addressed as a standard part of the analyses or considered, called out and addressed within the PSA/DEIS. Please see the attached, Appendix 1 of the Executive Summary, for a list of all comments received and addressed within the PSA/DEIS. Responses can be found in the "Response to Comments" subsection of most technical sections. The FSA/FEIS will also contain staff responses to all comments filed on the PSA/DEIS up to the end of the noticed public comment period.

ENVIRONMENTAL JUSTICE

California law defines environmental justice as "the fair treatment of people of all races, cultures, and income with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies" (Government Code Section 65040.12 and Public Resources Code Section 72000).

All Departments, Boards, Commissions, Conservancies and Special Programs of the California Natural Resources Agency must consider environmental justice in their decision-making process if their actions have an impact on the environment, environmental laws, or policies. Such actions that require environmental justice consideration may include:

- adopting regulations;
- enforcing environmental laws or regulations;
- making discretionary decisions or taking actions that affect the environment;
- providing funding for activities affecting the environment; and
- interacting with the public on environmental issues.

In considering environmental justice in energy facility siting cases, staff uses a demographic screening analysis to determine whether a low-income and/or minority population exists with the potentially affected area of the proposed site. The demographic screening is based on information contained in two documents: Environmental Justice: Guidance Under the National Environmental Policy Act (Council on Environmental Quality, December, 1997) and Guidance for Incorporating

Environmental Justice Concerns in EPA's Compliance Analyses (U.S. Environmental Protection Agency, April, 1998). Due to the change in the sources and methods of collection used by the U.S. Census Bureau, the screening process relies on Year 2010 U.S. Census data to determine the number of minority populations and data from the 2007-2011 American Community Survey (ACS) to calculate the population below-poverty-level. Staff's demographic screening is designed to determine the existence of a minority or below-poverty-level population or both within the area of the proposed project.

Environmental Justice: Guidance Under the National Environmental Policy Act, defines minority individuals as members of the following groups: American Indian or Alaskan Native; Asian or Pacific Islander; Black, not of Hispanic origin; or Hispanic. A minority population is identified when the minority population of the potentially affected area is:

1. greater than 50 percent;
2. or when the minority population percentage of the area is meaningfully greater than the minority population percentage in the general population or other appropriate unit of geographic analysis.

In addition to the demographic screening analysis, staff and DOE follow the steps recommended by the U.S. EPA's guidance documents in regard to outreach and involvement; and if warranted, a detailed examination of the distribution of impacts on segments of the population.

Staff and DOE have followed each of the above steps for the following thirteen sections in the PSA: **Air Quality, Cultural Resources, Hazardous Materials Management, Land Use, Noise and Vibration, Public Health, Socioeconomics, Soil and Water Resources, Water Supply, Traffic and Transportation, Transmission Line Safety and Nuisance, Visual Resources,** and **Waste Management**. Over the course of the analysis for each of these technical disciplines, staff considered potential impacts and mitigation measures, and whether there would be a significant impact on an environmental justice population.

To assess the potential presence of an environmental justice population in the project area, staff first estimated two radii encompassing areas equal to 6-miles from the center points of the HECA power plant site and the CO_2 processing facility site, respectively. Staff then merged the two radii to create a combined buffer area. **Socioeconomics Table 2** presents data on the minority population within the buffer area, as well as for a variety of surrounding communities and for an assortment of comparison geographies.

According to the latest decennial census, the 2010 resident population of the census blocks located within the buffer area was 3,663 persons. The minority population was 1,850 persons, which equaled roughly 51 percent of the total population.

Notable population centers located within the buffer area include Buttonwillow, Dustin Acres, Tupman, and Valley Acres. Buttonwillow had a total population of 1,508 and a minority population of 1,254, equal to nearly 83 percent minority. Dustin Acres had a total population of 652, with a minority population of 159, or around 24 percent. Tupman had a smaller population with 161 residents, and a minority population of 22 residents, equal to around 14 percent. Valley Acres had a total population of 527, with a minority population of 148, or around 28 percent.

Other notable communities located in the general project area include Bakersfield, Derby Acres, Fellows, Ford City, Maricopa, McKittrick, South Taft, Taft, Taft Heights, and Wasco. Of these, Bakersfield had a 62 percent minority population, while Ford City was 50 percent minority and Wasco was nearly 86 percent minority. Kern County as a whole showed a minority population equal to more than 61 percent of the total population. The HECA project site and the CO_2 processing site are located within two different Census County Divisions (CCDs). The Buttonwillow CCD had a minority population of nearly 67 percent, while the West Kern CCD had a minority population of only around 36 percent. **Socioeconomics Table 2** provides additional data for these geographies for comparison purposes.

Below-Poverty-Level-Populations as discussed in the **Socioeconomics** section - **Socioeconomics Table 3** shows estimates of the population living below-poverty-level from the 2007-2011 ACS Five-Year Estimates. According to this data, approximately 1,390 people in the combined census tracts intersecting the project buffer area, about 21 percent, lived below the federal poverty threshold between 2007 and 2011.

Because the minority population located within the buffer area was greater than 50 percent of the total population, staff and DOE conclude that the minority population located within the buffer area does constitute an environmental justice population, as defined above. Construction and operation of the proposed HECA project, including the associated EOR operation, could therefore have adverse or disproportionate impacts on an environmental justice population. Please refer to each technical section to identify whether the project has significant, unmitigated impacts on the above identified environmental justice population.

DEPARTMENT OF ENERGY'S SUMMARY STATEMENT

Preamble

The National Environmental Policy Act (NEPA)

PURPOSE AND NEED FOR DEPARTMENT OF ENERGY ACTION

This chapter introduces the Proposed Action of the Department of Energy (DOE), describes the purpose and need for DOE's action, and outlines the scope of the DOE's NEPA analysis contained in this Preliminary Staff Assessment and Draft Environmental Impact Statement (PSA/DEIS) . This section also summarizes DOE's process, project objectives, and the public scoping process undertaken for this PSA/DEIS.

INTRODUCTION

DOE proposes to provide federal financial assistance to Hydrogen Energy California, LLC (HECA) for its proposed project (the “project”), which would demonstrate integrated gasification combined cycle (IGCC) technology with carbon capture in a new electricity generating plant in Kern County, California. DOE has prepared this PSA/DEIS in accordance with NEPA (42 United States Code [U.S.C.] §§ 4321 et seq.), regulations implementing NEPA promulgated by the Council on Environmental Quality (Title 40, Code of Federal Regulations [C.F.R.] Parts 1500–1508), and DOE’s NEPA procedures (10 C.F.R. Part 1021). This PSA/DEIS describes the potential environmental impacts associated with DOE’s proposed action (providing financial assistance), the project itself (including aspects of the project that DOE would not fund), and alternatives to and options for the project, including the No Action Alternative. DOE will use this PSA/DEIS to inform its decision on whether to provide financial assistance for construction and demonstration of the project and, if so, whether it should impose environmental mitigation measures as a condition of its financial assistance for these activities.

HECA would construct its electricity and fertilizer production facility on a site currently used for agriculture in Kern County. The 1,106 acre site (453 acres of which would be used for the project and 653 acres for a controlled buffer area) is in south-central California near the unincorporated community of Tupman, approximately 7 miles west of the western border of the city of Bakersfield. The site’s topography is relatively flat, low-lying terrain that gently slopes from southeast to northwest. The site and surrounding areas are used for agricultural purposes, including cultivation of cotton, alfalfa, and onions. HECA’s facility would capture about 90 percent of the carbon dioxide (CO_2) produced by the gasification process. Most of this captured CO_2 would be transported via a new pipeline to a nearby oil field owned by Occidental of Elk Hills, Inc. (OEHI), where it would be sequestered through its use for enhanced oil recovery (EOR). HECA would use a small portion of the captured CO_2 to produce urea fertilizer and other nitrogenous compounds.

CLEAN COAL POWER INITIATIVE

Since the early 1970s, DOE and its predecessor agencies have pursued research and development programs that include large, technically complex projects in order to spur innovation in a wide variety of coal technologies through the proof-of-concept stage. However, helping a technology reach the proof-of-concept stage does not ensure its continued development or commercialization. Before a technology can be considered seriously for commercialization, it must be demonstrated at a sufficient scale to prove its reliability and economic competitiveness. The financial risk associated with such large-scale demonstration projects is often too high for the private sector to assume in the absence of strong incentives.

The Clean Coal Power Initiative (CCPI) program was established in 2002 as a government and private sector partnership to implement the recommendation in President Bush's National Energy Policy to increase investment in clean coal technology. Through cooperative agreements with its private sector partners, the program advances clean coal technologies to commercialization. These technologies involve combustion improvements, control systems advances, gasifier design, pollution reduction (including greenhouse gas reduction), efficiency increases, fuel processing, and others.

Congress established criteria for projects receiving financial assistance under this program in Title IV of the Energy Policy Act of 2005 (Pub. L.109-58) (EPACT 2005). Under this statute, CCPI projects must "advance efficiency, environmental performance, and cost competitiveness well beyond the level of technologies that are in commercial service" (Pub. L. 109-58, § 402(a)). In February 2009, the American Recovery and Reinvestment Act of 2009 (Pub. L. 111-5, 123 Stat. 115 (Feb. 17, 2009)) (ARRA) appropriated $3.4 billion to DOE for "Fossil Energy Research and Development;" the Department is using a significant portion of these funds to provide financial assistance to CCPI projects.

DOE's CCPI program selects projects for its government-private sector partnerships through an open and competitive process. Potential private sector partners may include developers of technologies, utilities and other energy producers, service corporations, research and development firms, software developers, academia and others. DOE issues funding opportunity announcements that specify the types of projects it is seeking, and invites submission of applications. Applications are reviewed according to the criteria specified in the funding opportunity announcement; these criteria include technical, financial, environmental, and other considerations. DOE selects the projects that demonstrate the most promise when evaluated against these criteria, and enters into a cooperative agreement with the applicant. These agreements set out the project's objectives, the obligations of the parties, and other features of the partnership. Applicants must agree to provide at least 50 percent of their project's cost; for most CCPI projects, the applicant's cost share will be much greater if the project proceeds to completion.

To date, the CCPI program has conducted three rounds of solicitations and project selections. The first round sought projects that would demonstrate advanced technologies for power generation, improvements in plant efficiency, economics, and environmental performance. Round 2 requested applications for projects that would demonstrate improved mercury controls and gasification technology. Round 3, which DOE conducted in two phases, sought projects that would demonstrate advanced coal-based electricity generating technologies which capture and sequester (or put to beneficial use) carbon dioxide emissions. DOE's overarching goal for Round 3 projects was to demonstrate technologies at commercial scale in a commercial setting that would: (1) operate at 90 percent capture efficiency for CO_2; (2) make progress towards capture and sequestration at less than a 10 percent increase in the cost of electricity for gasification systems and a less than 35 percent increase for combustion and oxycombustion systems; and (3) make progress toward capture and sequestration of 50 percent of the facility's CO_2 output at a scale sufficient to evaluate the full impacts of carbon capture technology on a generating plant's operations, economics and performance.

The HECA project was one of two selected in the first phase of Round 3. DOE entered into a cooperative agreement with HECA on September 30, 2009, and began the NEPA process. HECA had already begun to seek the regulatory authorizations needed for the project, including certification by the Energy Commission and environmental permits from other agencies before its project was selected to receive financial assistance from DOE. It continued to seek these approvals and permits until September 2, 2011, when SCS Energy California LLC (SCS Energy) acquired HECA from BP Alternative Energy North America Inc. (BP), and Rio Tinto Hydrogen Energy LLC (Rio Tinto). Because SCS Energy intended to make several modifications to the project – including the addition of fertilizer production capabilities – the NEPA and regulatory processes were suspended until HECA submitted an Amended Application for Certification (AFC) to the Energy Commission on May 2, 2012.

DOE'S NEPA STRATEGY

In compliance with NEPA, this PSA/DEIS will be used by DOE decision-makers to inform their decision on whether to provide financial assistance for detailed design, construction, and operation of the project. This PSA/DEIS evaluates the environmental impacts of alternatives and connected actions and provides a means for the public to participate in the decision-making process.

DOE developed an overall strategy for compliance with NEPA for its CCPI program consistent with CEQ regulations (40 CFR 1500 through 1508) and DOE regulations (10 CFR 1021). The strategy has two principal steps. The first step consists of an open solicitation and competitive selection process to obtain a set of projects that best meets program needs. Applications are screened for compliance with a number of basic eligibility requirements that are defined by the program. The set of applications that meet the mandatory eligibility requirements constitutes the range of reasonable alternatives available to DOE to meet the program's purpose and needs. Recognizing that the range of reasonable alternatives in the context of competitive financial assistance programs is in large part determined by the number and nature of the proposals submitted to DOE for consideration, section 216 of DOE's NEPA regulations requires the Department to prepare an "environmental critique" that assesses the environmental impacts and issues relating to each of the proposals that the DOE selecting official considers for an award. See 10 C.F.R. § 1021.216. This official considers these impacts and issues, along with other aspects of the proposals (such as technical merit and finance ability) and the program's objectives, in making awards. DOE prepared a critique of the proposals that were deemed suitable for selection in this round of awards for the CCPI program. Because the critique contains confidential business information, it is not made available to the public; a synopsis of the critique is included as **U.S. Department of Energy Documents**, **Appendix 1**, located in section 7-1 of the PSA/DEIS.

The second element of DOE's NEPA strategy consists of preparing a more detailed NEPA evaluation for each selected project. For this project, DOE determined that providing financial assistance for the proposed project would constitute a major federal action that may significantly affect the quality of the human environment. Therefore, DOE has prepared this PSA/DEIS to assess the potential impacts on the human environment of the proposed action and reasonable alternatives. DOE has used information provided by HECA for the proposed project, as well as information provided by state and federal government agencies, subject-matter experts, and others. This PSA/DEIS has been prepared in accordance with Section 102(2)(C) of NEPA, as implemented under regulations promulgated by CEQ (40 CFR 1500 through 1508) and as provided in DOE regulations for compliance with NEPA (10 CFR 1021).

The original Notice of Intent (NOI) to prepare an EIS for this project was published by DOE in the Federal Register on April 6, 2010 (75 FR 17397). The Amended Notice of Intent (ANOI) was published by DOE in the Federal Register on June 19, 2012 (77 FR 36519). A public scoping meeting was conducted on July 12, 2012, at the Elk Hills Elementary School in Tupman, California, and comments were accepted through August 3, 2012 (one week after July 27, 2012, the date the comment period closed).

Scope of DOE's NEPA Analysis

The PSA/DEIS will inform DOE's decision on whether to provide financial assistance under its CCPI Program for the construction and demonstration of HECA's project, which has an estimated capital cost of over $4 billion. DOE's financial assistance (or "cost share") would be limited to $408 million, about 10 percent of the project's total cost. DOE's financial assistance is also limited to certain aspects of the power and manufacturing plants, carbon capture, and sequestration. The PSA/DEIS evaluates the potential impacts of DOE's proposed action, the project proposed by HECA and any connected actions, cumulative impacts, and reasonable alternatives to DOE's proposed action.

Connected and Cumulative Actions

Under the cooperative agreement between DOE and HECA, DOE would share the costs of the gasifier, syngas cleanup systems, combustion turbine, steam generator, steam turbine, fertilizer production facilities, supporting facilities and infrastructure, and a demonstration phase in which the project would use captured CO_2 for EOR. Under this agreement, DOE would not share in the cost of the air separation unit, CO_2 EOR and sequestration facilities, or certain other facilities. Accordingly, DOE's NEPA process considers these aspects of HECA's project as connected actions. The impacts of these connected actions are evaluated in the same manner as the impacts of the parts of the project funded by DOE.

In addition to the impacts of the project and its connected actions, DOE's analysis of cumulative impacts such as greenhouse gas emissions and global warming, other air emissions, and other incremental impacts that, when added to past, present, and reasonably foreseeable impacts, may have significant effects on the human environment are separately discussed in the Carbon Sequestration and Green House Gas section of this document.

PURPOSE AND NEED

The purpose and need for DOE action – providing limited financial assistance for the construction and operation of HECA's project – is to advance DOE's CCPI program by funding projects that have the best chance of achieving the program's objective as established by Congress. The objective of the CCPI program is the commercialization of clean coal technologies that improve efficiency, environmental performance, and cost competitiveness well beyond those of technologies that are currently in commercial service.

DOE selected HECA's proposed project under the CCPI program as one in a portfolio of projects. That portfolio represents the most appropriate mix of projects to achieve CCPI program objectives and meet legislative requirements. Specifically, DOE's purpose and need for selecting the HECA project is to promote the commercialization of IGCC technologies that improve efficiency, environmental performance, and cost competitiveness.

PROPOSED ACTIONS

DOE's proposed action is to provide financial assistance for the detailed design, construction and operation of HECA's project, which would produce and sell electricity, carbon dioxide and fertilizer.

OVERVIEW OF HECA'S PROPOSED PROJECT

HECA's project would use integrated gasification combined cycle (IGCC) and carbon capture technology to meet market demands for producing and selling electricity, carbon dioxide, and fertilizer. The basic components and attributes of the project include:

- The use of an IGCC power system to demonstrate pre-combustion carbon dioxide capture and sequestration technology on a commercial scale that provides dependable, low-carbon electricity from a plant whose output can be adjusted so as to back up intermittent renewable power sources, increasing the reliability of the grid;
- capture of 90 percent of the CO_2 generated by the facility;
- transportation of most of the CO_2 to the Elk Hills Oil Field for use in EOR, resulting in its sequestration;
- advanced air emissions controls;
- use of brackish water for process water needs;
- zero liquid discharge;
- an integrated manufacturing plant producing approximately 1 million tons per year of nitrogenous compounds such as urea, urea ammonium nitrate (UAN) and anhydrous ammonia to be used in agricultural, transportation and industrial applications;
- use of a single Mitsubishi Heavy Industries' (MHI) oxygen-blown dry feed gasifier and an MHI 501 GAC© combustion turbine;

- use of a blend of 75 percent coal and 25 percent petcoke as fuel throughout the life of the facility;
- use of natural gas for start-up, shut down and equipment outages only, not for routine operation of the turbine.

The project would capture approximately 3 million tons per year of CO_2; 2.6 million tons would be permanently sequestered as a result of its use for EOR. While most of the captured CO_2 (about 90 percent of the amount captured) would be used for EOR at the nearby Elk Hills Oil Field, about 0.4 million tons per year of the captured CO_2 would be used to manufacture fertilizer; DOE does not considered this CO_2 to be sequestered.

Proposed Generating Plant

The HECA project would demonstrate IGCC and carbon capture technology on a commercial scale in a new power plant consisting of a single gasifier with gas cleanup systems, a hydrogen-rich fired combustion turbine, a heat recovery steam generator, a steam turbine, and associated facilities.

The plant would gasify coal and petcoke to produce syngas, which would then be processed and purified to produce a hydrogen-rich fuel. The hydrogen would be used to drive the gas combustion turbine. Hot exhaust gas from the gas combustion turbine would generate steam from water in the heat recovery steam generator to drive the steam turbine; both turbines would generate electricity. At full capacity, the plant is expected to use about 4,580 tons of coal and about 1,140 tons of petcoke per day (about 162 million tons and 400,000 tons per year, respectively).

Combined, the gas combustion and steam turbines would have the capacity to generate between 405 and 431 MW (gross) of electricity, compared to the 390 MW gross and 288 MW net anticipated from the plant as originally proposed by British Petroleum (BP) and Rio Tinto. However, the net new capacity added to the electrical grid is lower due to the additional products generated by the current design. This combined-cycle approach (using gas and steam turbines in tandem) increases the amount of electricity that can be generated from the feedstock, but the additional products reduce the net generation.

The proposed facility would minimize emissions of sulfur dioxide, nitrogen oxides, mercury, and particulates compared to conventional coal-fired power plants. The local air pollution control district is requiring additional mitigation in the form of emissions reductions with the intent that the facility would emit no more nitrogen oxide pollution than a natural gas fired power plant.

The facility would incorporate state-of-the-art air emission controls that reflect or exceed Best Available Control Technology. It is expected that these controls would remove in excess of 99 percent of the sulfur dioxide produced by the plant and would also limit emissions of nitrogen oxides, carbon monoxide and volatile organic compounds. In addition, over 99 percent of the mercury in the feedstock would be removed and over 99 percent of the particulates in the syngas would be removed using liquid scrubbing. Solids generated by the gasifier would be accumulated onsite (up to 7 days worth) and made available for appropriate recycling or beneficial use. If these options were not available, HECA would dispose of these solids in accordance with applicable laws. Unlike the gasifiers that BP and Rio Tinto originally planned to use, the MHI gasifier would not produce solids with fuel value, and therefore solids would not be returned to the gasification process as had been originally planned.

In addition to the gasifier and turbines, the power plant's equipment would include exhaust stacks, mechanical-draft cooling towers, syngas cleanup facilities, and particulate filtration systems. The height of the tallest proposed structure would be approximately 305 feet above ground (a flare stack). Flares are designed for combusting emissions resulting from startups or outages, or during emergencies. The plant would also require systems for feedstock handling and storage, as well as on-site roads, administration buildings, water and wastewater treatment systems, and facilities for handling gasification solids.

Proposed Fertilizer Production Facilities

A portion of the clean hydrogen-rich fuel would be used as a feedstock for the ammonia synthesis unit, which would have a capacity of 2,000 tons per day of ammonia. The ammonia would be used as an intermediate for the production of urea for sale. The project's fertilizer manufacturing complex would convert urea into urea ammonium nitrate and urea pastilles (small solid pellets). The pastilles unit would have a capacity of about 1,700 tons per day.

Proposed Linear Facilities

Linear facilities are the pipelines, electrical lines, and railways used to transport materials and power to and from the plant. The plant's process water would be brackish groundwater supplied by the Buena Vista Water Storage District; approximately 4,600 gallons per minute (average annual basis) would be required for cooling water makeup, steam cycle makeup, and other processes. The process water pipeline would be approximately 15 miles in length. Potable water for drinking and sanitation would be supplied by the West Kern Water District. The potable water line would be approximately 1 mile in length. The project would recycle water and would incorporate zero liquid discharge (ZLD) technology for process and other wastewater from plant operations. Therefore, there would be no industrial wastewater discharge. Sanitary wastewater would be disposed of in an onsite leach field (e.g., a septic system) in accordance with applicable law.

HECA would connect to the PG&E Midway Substation via a 230 kV Midway-Wheeler Ridge transmission line and a new PG&E switching station. A 230 kV, single pole, double circuit capacity transmission line would be built to transmit the plant's electricity. The line would be approximately 2 miles in length.

An approximately 13-mile natural gas pipeline would connect with an existing PG&E pipeline north of the project site, and an approximately 3-mile CO_2 pipeline would extend from the site to the Elk Hills Oil Field. HECA has proposed two alternatives for coal transportation to the site. Alternative 1 consists of an approximately 5-mile new railroad spur that would connect the site to the San Joaquin Railroad's Buttonwillow line. Alternative 2 would use the 27-mile truck route proposed by BP and Rio Tinto to transport coal using 400 round trips each day from an existing coal transloading facility in Wasco, California.

Proposed Use of CO_2 for EOR and Sequestration

The project would result in the sequestration of about 2.6 million tons of CO_2 per year during the demonstration phase that DOE would fund rather than the two million tons originally proposed by BP and Rio Tinto. HECA anticipates this rate of sequestration would continue for the operational life of the power plant due to the requirements of California law and the value created by the use of the CO_2 for EOR. The captured CO_2 would be compressed and transported via pipeline to the Elk Hills Oil Field approximately 3 miles from the power plant. The CO_2 would enhance domestic oil production, contributing to the nation's energy security. An additional small amount of the CO_2 produced by the facility would be used to manufacture urea.

The EOR process involves the injection and reinjection of CO_2 to reduce the viscosity and enhance other properties of trapped oil in order to facilitate its flow through the reservoir, improving extraction. During EOR operations, the pore space left by the extracted oil is occupied by a portion of the injected CO_2, sequestering it in the geologic formation. The remainder of the CO_2 is produced with the oil, and it must be separated from the oil, recompressed, and then re-injected into the formation.

Proposed Project Schedule

The project proposed by HECA includes engineering and design, permitting of the plant and associated facilities, equipment procurement, construction, startup, operations, and demonstration of the IGCC technology and CO_2 sequestration. HECA anticipates that it would take about four years to construct, commission, and commence operation of the plant. The estimated project schedule would be start of construction activities in January 2014 and commencing commercial operation by February 2018. This schedule is contingent upon HECA receiving the necessary regulatory authorizations (which would be preceded by the hearings and other events mandated by the regulatory agencies' procedures) and upon DOE deciding to provide financial assistance for the construction and demonstration phases of the project (a decision that would occur after completion of DOE's NEPA and Energy Commission's certification processes).

PROPOSED PROJECT AND ALTERNATIVES

PROPOSED PROJECT

DOE's proposed action is to provide financial assistance for the construction and operation of HECA's project, which would produce and sell electricity, carbon dioxide and fertilizer. DOE selected this project for an award of financial assistance through a competitive process under the Clean Coal Power Initiative (CCPI) program.

HECA's project would demonstrate integrated gasification combined cycle (IGCC) technology with carbon capture in a new electricity generating plant in Kern County, California. The plant would use a blend of 75 percent coal and 25 percent petroleum coke (petcoke) and would capture, sell and sequester carbon dioxide on a commercial scale. It would also produce and sell fertilizer and other nitrogenous compounds.

The project would gasify the coal and petcoke to produce synthesis gas (syngas), which would then be purified to produce a hydrogen-rich fuel for a combustion turbine that would generate electricity while minimizing emissions of sulfur dioxide, nitrogen oxides, mercury, and particulates compared to conventional coal-fired power plants. In addition, the project would achieve a carbon dioxide (CO_2) capture efficiency of approximately 90 percent at steady-state operation. The captured CO_2 would be compressed and transported via pipeline to the adjacent Elk Hills Oil Field (owned and operated by Occidental of Elk Hills, Inc. (OEHI)) for injection into deep underground oil reservoirs for enhanced oil recovery (EOR), resulting in geologic sequestration.

Project Site Location and General Description

HECA would construct its electricity and fertilizer production facility on a site currently used for agriculture in Kern County, California. The 1,106 acre site (453 acres of which would be used for the project and 653 acres for a controlled buffer area) is in south-central California near the unincorporated community of Tupman, approximately 7 miles west of the western border of the city of Bakersfield. The site's topography is relatively flat, low-lying terrain that slopes very gently from southeast to northwest. The site and surrounding areas are used for agricultural purposes, including cultivation of cotton, alfalfa, and onions.

ALTERNATIVES

NEPA requires that a federal agency evaluate the range of reasonable alternatives to its proposed action. The range of reasonable alternatives encompasses those alternatives that would satisfy the underlying purpose and need for agency action. The purpose and need for DOE action – providing limited financial assistance to the HECA IGCC project – are to advance the CCPI program by selecting projects that have the best chance of achieving the program's objective as established by Congress: the commercialization of clean coal technologies that advance efficiency, environmental performance, and cost competitiveness well beyond the level of technologies that are currently in service.

DOE's NEPA regulations include a process for identifying and analyzing reasonable alternatives in the context of providing financial assistance through a competitive selection of projects proposed by entities outside the federal government. The range of reasonable alternatives in competitions for grants, loans and other financial support is defined in large part by the range of responsive proposals DOE receives. Unlike projects undertaken by DOE itself, the Department cannot mandate what outside entities propose, where they propose to do it, or how they propose to do it beyond establishing requirements in the funding opportunity announcement that further the program's objectives. DOE's decision is limited to selecting among the applications submitted by project sponsors that meet CCPI's goals.

Recognizing that the range of reasonable alternatives in the context of financial assistance and contracting is in large part determined by the number and nature of the proposals submitted, section 216 of DOE's NEPA regulations requires the Department to prepare an "environmental critique" that assesses the environmental impacts and issues relating to each of the proposals that the DOE selecting official considers prior to making a selection. See 10 C.F.R. § 1021.216. This official considers these impacts and issues, along with other aspects of the proposals (such as technical merit and financial ability) and the program's objectives, in making awards. DOE prepared a critique of the proposals that were deemed suitable for selection in this round of awards for the CCPI program.

Once DOE selects a project for an award, the range of reasonable alternatives becomes the project as proposed by the applicant, any alternatives still under consideration by the applicant or that are reasonable within the confines of the project as proposed (e.g., the particular location of the generating plant on the 1,106-acre site or the rights-of-way (ROWs) for linear facilities), and a no action alternative. Regarding the no action alternative, DOE assumes for purposes of the PSA&DEIS that, if it were to decide to withhold financial assistance for construction and operation of the project, it would not proceed. DOE currently plans to analyze the project as proposed by HECA (with and without any mitigating conditions that DOE or the Energy Commission may identify as reasonable and appropriate); alternatives to HECA's project that it is still considering (e.g., the rights of way for linear facilities or methods of transporting coal to site); and the no action alternative.

DOE'S No-Action Alternative

Under the no action alternative, DOE would not provide funding to HECA for construction and operation of its project. In the absence of financial assistance from DOE, HECA could reasonably pursue two options. It could build the project without DOE funding; the impacts of this option would be essentially the same as those of DOE's proposed action. Or, HECA could choose not to pursue its project, and there would be no impacts from the project. This option would not contribute to the goal of the CCPI program, which is to accelerate commercial deployment of advanced coal technologies that provide the United States with clean, reliable, and affordable energy. However, as required by NEPA, DOE analyzes this option as the no action alternative in order to have a meaningful comparison between the impacts of DOE providing financial assistance and withholding that assistance.

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA) ALTERNATIVES SUMMARY

Staff evaluated a number of potentially feasible alternatives, ruled out most in the initial screening process, carried others forward and continues to further develop those alternatives to reach conclusions under CEQA.

- Alternative sites evaluated in the subsection "Alternatives Eliminated from Detailed Consideration" focused on locations proximate to the EHOF.

- As described in the subsection "Alternatives Eliminated From Detailed Consideration," staff has eliminated the Natural Gas Project Alternative which consists of a conventional natural gas-fired electric generation facility that would generate electricity but would not meet the DOE goal of demonstrating an advanced coal-based electricity generating technology which would include CO_2 capture or storage, EOR at the Elk Hills Oil Field, or the applicant's goals of production of any fertilizer or other nitrogen-based products. A natural gas alternative with CO_2 capture and storage will be analyzed in the FSA/FEIS.
- A Dry Cooling or Wet-Dry Hybrid Cooling Alternative will be evaluated in the FSA/FEIS to determine if it can reduce HECA's water consumption.
- Staff is considering an alternative that would consist of a biomass-fired boiler that would provide the same net new electrical capacity and energy as HECA. This alternative may not provide carbon capture and storage, but would provide a new, local renewable energy facility with a low-carbon footprint, depending on how far the biomass would have to be transported to the facility site.
- Based upon staff's analysis, the No Project Alternative would eliminate potentially significant environmental impacts associated with the HECA project, while the No Fertilizer Manufacturing Complex Alternative (Reduced Project Alternative) would lessen impacts in a number of environmental issue areas.
- The HECA project includes both rail and truck options for coal delivery from the rail transfer point. These options are analyzed in the **Traffic and Transportation** and **Land Use** sections of this PSA/DEIS.
- The identification of a CEQA environmentally superior alternative and NEPA environmentally preferred alternative will be identified in the FSA/FEIS.

NOTEWORTHY PUBLIC BENEFITS

Noteworthy public benefits that would result from the HECA project are as follows:

SOCIOECONOMICS

Public benefits include the changes in local economic activity and tax revenue that would result from project construction and operation.

The applicant estimated that the total construction cost for the whole of the project would be around $4 billion. The total direct labor costs for construction would equal roughly $1.37 billion. The remaining $1.78 billion includes other non-labor expenditures, such as project engineering and materials procurement. Note that these are gross figures, which do not account for economic leakage. Based on these direct expenditures, the applicant anticipates that the project would generate roughly $843 million in indirect and induced economic output, as well as $294 million in additional labor income.

For operations, the applicant estimated that the project as a whole would generate around $30 million in direct labor income. The indirect and induced impacts of project operations, including both HECA and the OEHI EOR projects, would reportedly include the annual maintenance of 430 jobs, $21 million in labor income, and $68 million in economic output.

Property Tax

Staff estimates that the capital cost attributable to the construction of the HECA power plant would equal roughly $2.6 billion. At the applicable 1.09 percent property tax rate, this would generate nearly $28.7 million in annual property tax revenue. The rail spur, likewise, would account for around $26 million in capital costs, which would translate to between $278,000 and $285,900 in annual property tax revenue. Together, the HECA power plant and rail spur could generate upwards of $28.9 million in annual property tax revenue.

According to the California Department of Conservation (CDC), the State of California does not levy severance taxes on oil and natural gas production (CDC 2012a). The state does levy an assessment on the value of oil and natural gas produced. The Oil and Gas Assessment rate for fiscal year 2012-2013 is 14.06207 cents per barrel of oil or 10 million cubic feet (Mcf) of natural gas produced (CDC 2012b). An increase in the amount of oil produced due to implementation of the EOR project would correlate to an increase in the assessed value of oil and natural gas production and in the revenues received by the CDC's Division of Oil, Gas, and Geothermal Resources.

PRELIMINARY CONCLUSIONS

Energy Commission staff briefly highlights those technical sections that have identified potential significant, unmitigated impacts or those sections requiring additional information below.

Air Quality

The Hydrogen Energy California Project should comply with all applicable air quality laws, ordinances, regulations, and standards and should not result in significant air quality impacts provided the recommended conditions of certification are adopted by the Commission and implemented by the project owner. The project has secured emission reduction credits in sufficient quantity to meet San Joaquin Valley Air Pollution Control District requirements. The applicant has also agreed to provide funding to the San Joaquin Valley Air Pollution Control District's Emission Reduction Incentive Program to create additional emissions reductions necessary for General Conformity.

These emission reduction credits and emissions reductions created from the mitigation agreement funding would fully offset all onsite project emissions of nonattainment pollutants and their precursors that occur within the San Joaquin Valley Air Basin at a minimum offset ratio of 1:1, and would fully offset the offsite NOx emissions as required for General Conformity. If built and operated as described in the Amended AFC, and if the permitting authority implements construction and operating conditions equivalent to those recommended by Energy Commission staff, the Occidental Petroleum Carbon Dioxide Enhanced Oil Recovery component would also comply with all applicable air quality laws, ordinances, regulations, and standards. Energy Commission staff is requesting additional information from the applicant prior to publishing the FSA/FEIS.

Carbon Sequestration and Greenhouse Gas Emissions

HECA's likely operating profile is not known although the applicant has described the facility's expected operation using more than one potential operating profile. Different operating profiles may need to be evaluated to determine which set of operating conditions represent actual operations and worst case impacts. Some operating profiles may result in the facility not complying with certain regulatory requirements. For example, a profile provided by the applicant indicated reduced electricity production for eight hours each day, reducing the portion of the hydrogen-rich gas used to produce electricity and increasing that used to produce fertilizer. Under this operating profile, the project may not comply with California's Greenhouse Gases (GHG) Emission Performance Standard (EPS) during early operating years. Staff has asked for additional information in order to resolve this issue.

Assuming the above issue is resolved, the project could meet the EPS that applies to long-term utility purchases of base load power from power plants (Title 20, California Code of Regulations, section 2900 et seq.), if the majority of HECA's CO_2 emissions are permanently sequestered. Staff is in the process of designing conditions of certification that would enforce the carbon sequestration that is necessary for this project to comply with this regulation. Staff has provided preliminary conditions of certification that outline the type of requirements that will be recommended by staff; however, significant additional detail will be added to these conditions in the FSA and additional conditions may be required for the facility to comply with the EPS so they could sell electricity to a California electric utility under a long-term contract.

BIOLOGICAL RESOURCES

Blunt-nosed leopard lizard (BNLL) is a California fully protected species under California Fish and Game Code Section 5050 and therefore, incidental take of the species is not legally permitted as defined by Section 86 of the Fish and Game Code. This species is present at the Elk Hills Oil Field and has a high potential to occupy the proposed carbon dioxide pipeline route as well as disturbed allscale scrub areas along the natural gas pipeline. The construction of the project would impact approximately 192 acres of natural allscale scrub and disturbed lands which provide small mammal burrow habitat for BNLL; this poses a threat to BNLL in the form of mortality from vehicles and equipment on roadways, entrapment in construction-related trenches or pipes, burial in burrows by equipment, avoidance of certain habitats, modification to breeding and/or foraging behaviors, and reduced carrying capacity of natural scrub habitat and neighboring lands known to be occupied by BNLL. Staff has proposed a condition of certification to mitigate this impact to the extent feasible, but even with the implementation of staff's proposed take avoidance and minimization measures, incidental take of blunt-nosed leopard lizard would likely occur over the life of the project. Therefore, staff considers this impact significant and unavoidable under CEQA even with the incorporation of mitigation. It is also unclear whether the project would comply with Fish and Game Code Section 5050 relating to Fully Protected Reptile and

Amphibian Species and the California Endangered Species Act since avoiding take of this species cannot be guaranteed for the life of the project.

During protocol-level surveys performed for Swainson's hawk, 12 active raptor nests were found within the survey area, six of which were confirmed Swainson's hawk nests. All six Swainson's hawk nests appear to be within a 0.25 mile of either the project site or a proposed linear facility and therefore could be affected by construction noise or other construction disturbances during the nesting season. The majority of these nest trees occur along canal levees of the Kern River Flood Control Channel, West Side Canal and other smaller unnamed agricultural canals and ditches and are likely supplied to some extent by irrigation runoff that accumulates in irrigation canals as well as groundwater. In addition, valley sink scrub, a sensitive vegetation community identified by the California Natural Diversity Database, potentially occurs in these same areas in association with the Kern River Flood Control Channel. Staff believes that a more definitive analysis is needed on the water source of the nest trees that occur in the project area and pre- and post-project groundwater drawdown around the proposed well field.

Staff also believes the loss of approximately 571 acres of agricultural lands including alfalfa, wheat, onion fields, and other low-growing crop types that provide forage value is a significant loss of foraging habitat for Swainson's hawk. More definitive analysis is needed on the baseline groundwater levels and water source of the nest trees and sensitive vegetation communities that occur in the project area. Until additional data is provided regarding the project's impacts and overall mitigation strategy, staff cannot determine if the project's impacts to Swainson's hawk habitat would be reduced to below a level of significance. If groundwater drawdown from HECA's proposed well field and along the 15-mile processed water pipeline is consistent enough over the course of several years, staff believes the decrease in water supply to the root system of the trees could result in gradual decline and eventually nest tree failure which may constitute take under the California Endangered Species Act, the Migratory Bird Treaty Act, and California Fish and Game Code 3503; therefore, it is unknown if HECA complies with these LORS at this time.

The applicant has proposed to mitigate for permanent and temporary habitat impacts to federally and state listed species at a 0.1:1 and 2.1:1 ratio, respectively, which staff believes would not suffice as adequate habitat compensation for project impacts to special-status species (HECA 2012b, URS 2013b). The applicant has also proposed to purchase habitat credits from the Kern Water Bank as mitigation for the project, which the wildlife agencies have indicated is not a feasible option for mitigating HECA's impacts to special-status wildlife species. The CDFW and USFWS have indicated that while it may be possible to purchase some mitigation credits for a portion of the listed species that would be impacted, it is not feasible to mitigate HECA entirely at the Kern Water Bank, given the nature of the project's impacts to listed wildlife species from project traffic road mortality and habitat loss.

During May 2013, the applicant submitted a Section 2081 Incidental Take Permit application for project impacts to state-listed wildlife species for which the applicant would be seeking incidental take coverage which staff has preliminarily reviewed (URS 2013d). Staff has inserted Condition of Certification BIO-20 (Compensatory Habitat Mitigation for Upland Species) as a placeholder. Staff will continue to work with the applicant, CDFW, and USFWS to develop an appropriate mitigation strategy for HECA that is consistent with the goals and objectives of the Recovery Plan for Upland Species of the San Joaquin Valley. Additional conditions of certification, and modifications to currently proposed conditions of certification including Condition of Certification BIO-20, are likely to be necessary based on further consultation with the wildlife agencies and information provided by the applicant. With the implementation of staff's proposed Conditions of Certification BIO-1 through BIO-20, impacts to special-status species would be reduced; however, without an adequate mitigation proposal, staff cannot make a determination whether the project would comply with all applicable LORS or that project impacts to sensitive biological resources would be reduced to less than significant levels in accordance with CEQA.

CULTURAL RESOURCES

Staff tentatively concludes that the proposed HECA project would have a significant direct impact on historical resources and historic properties, as defined by the California Environmental Quality Act and Section 106 of the National Historic Preservation Act. Significant impacts may be incurred upon as many as 21 known, significant archaeological resources and as many as four known, significant historic built environment resources. Additionally, the proposed project could result in significant adverse changes to an unknown number of as-yet-unidentified, buried archaeological resources. Field work and limited archeological excavations are ongoing at this time.

Staff believes HECA and related OEHI components would result in direct and indirect impacts to National Register of Historic Places/California Register of Historical Resources (NRHP/CRHR)-eligible cultural resources. However, staff requires additional information about cultural resources in order to complete its analysis.

LAND USE

While the project would be a conditionally permitted use pursuant to the county zoning ordinance, one finding that must be made by the Energy Commission's Committee is that "the proposed use will not be detrimental to the health, safety, and welfare of the public or to property and residents in the vicinity" (19.104.040(E)). Staff cannot recommend whether this finding should be made by the Committee, until the outstanding information identified in other technical areas is provided. Staff also needs additional information to determine project compliance with Sections 19.12.070 (setbacks) and 19.12.100 (parking) of the Kern County Zoning Ordinance.

POWER PLANT EFFICIENCY

There is a discrepancy in the applicant's documents concerning the gross output of the project. The AFC indicates it will be 405 MW while later filed documents appear to assume it will be 431 MW. Staff has requested additional information from the applicant to clarify.

POWER PLANT RELIABILITY

The applicant predicts an equivalent power block availability factor of at least 91.3 percent, which staff believes is possible upon the successful completion of the requisite one to two years of pilot to mature operations. The applicant has failed to: 1) demonstrate adequate reliability of the project's industrial water supply, and 2) assign availability to the gasification system and ancillary systems upon which the power block is dependent. Staff has requested additional information to address these issues.

TRAFFIC AND TRANSPORTATION

Although potentially significant impacts associated with implementation of the proposed HECA project can be reduced with recommended conditions of certification, staff has concerns that the project has the potential to substantially increase traffic levels on farming roads not currently intended for heavy truck traffic and heavy load capacities. This substantial increase in traffic also has the potential to impact traffic associated with existing farming activities (e.g., tractors traveling on public roadway) thereby potentially resulting in safety issues and increased accidents to the public. Based on a recent Board of Supervisor's meeting held on February 26, 2013, the Board instructed the Public Works Department to review the roadways intended for heavy truck and worker traffic and report back at their June 2013 Board meeting as to recommendations for improvements to the local roadway system. Staff will address the concerns and/or recommendations by Kern County in the FSA.

Staff has also requested additional information from the applicant concerning the capacity of the Wasco transloading facility to handle the amount of coal anticipated, the applicant's recent proposal to truck in limestone fluxant, and information necessary to analyze the proposed at-grade rail crossings.

TRANSMISSION SYSTEM ENGINEERING

The Transition Cluster Phase II Interconnection Study Report (Phase II Study) for HECA is scheduled to be issued by early July, 2013. Staff expects to analyze the Phase II Study to determine the downstream distribution impacts and any required mitigation. The Phase I study indicated that no additional new transmission facilities that would require a CEQA review other than those proposed by the applicant are needed for the interconnection of the HECA project.

VISUAL RESOURCES

The HECA project would cause a significant visual impact at Key Observation Point (KOP) 1 (HECA). KOP 1 is located on Station Road, approximately 2,600 feet east of the middle of the HECA project site. Viewers at or near KOP 1 include residents at two adjacent properties near the intersection of Station Road and Tule Park Road and motorists on Station Road. The applicant intends to prepare and submit an off-site conceptual landscape plan to mitigate the significant impact at KOP 1, but staff is uncertain whether an offsite plan would be sufficient to mitigate to less than significant.

WASTE MANAGEMENT

The HECA project would produce thousands of tons per year of waste during the operation of the facility. The majority of the waste would be gasification solids. HECA is expected to generate a maximum of 850 tons per day of gasification waste (vitrified slag). HECA is currently investigating three potential markets for beneficial reuse of this material; 1) roofing granules, 2) blasting grit, 3) pozzolanic admixtures in cement manufacture. The large quantity of waste would significantly impact Kern County landfills and possibly compromise the county's compliance with Public Resources Code section 40000 et seq. and Senate Bill (SB) 1016 (Stats. 2008, ch. 343.) and implementing regulations (requiring jurisdictions such as Kern County to divert 50 percent of their waste from landfill disposal).

The gasification waste could be excluded from hazardous waste regulations (i.e., 40 C.F.R. § 261.4 (b) (7) (ii) (F) and Cal. Code Regs, tit. 22, § 66261.4(b) (5) (A)). However, prior to acceptance of the gasification solids into a Kern County owned and operated landfill the solids must be analyzed and classified as non-hazardous or hazardous waste. The HECA project owner has not produced a comprehensive plan for the reuse and disposal of the gasifier solids. HECA tested the gasification solids and they are considered non-hazardous according to federal standards. California testing standards should be used to determine if the HECA gasification solids are non-hazardous.

If the solids are determined to be hazardous, the amount of hazardous waste would be burdensome to the State of California and disposal would be costly to the applicant. If they are determined to be non-hazardous according to Title 14 regulations, nonhazardous waste quantities generated and/or disposed of in Kern County would count against the county's waste diversion goals. The expected volume of waste would likely result in the Kern County exceeding their state mandated waste diversion goals. The applicant has proposed to export waste for disposal so the diversion goals can be met. However, CalRecycle has indicated Kern County would still be responsible for the waste generated in the county. To avoid significant waste management impacts the project owner would have to work with Energy Commission, Kern County and CalRecycle staff to establish an operational waste diversion program. This plan must be completed and approved by the coordinating agencies prior to staff's publication of the Final Staff Assessment.

The results of soil sampling and analytical testing at the HECA project site indicate there are elevated concentrations of petroleum hydrocarbons and other contaminants affected by previous site activities. Staff is recommending the site be appropriately characterized prior to the Final Staff Assessment.

Staff has reviewed the waste management aspects of the Occidental of Elk Hills, Inc. CO_2 Enhanced Oil Recovery (OEHI CO_2 EOR) component of the project for construction and operation, as described in the Supplemental Environmental Information (SEI) report (HECA 2012e, Volume II). Nonhazardous and hazardous waste would be generated during construction and operation of the OEHI CO_2 EOR. In order to verify that Kern County has enough landfill capacity to accommodate the project's solid waste disposal needs, staff requires the project owner to provide information on the quantity of project waste that would be disposed of in local landfills.

WATER SUPPLY

Staff has preliminarily concluded the following regarding the project's proposed water use:

1. The project pumping could result in well interference and lower water levels in neighboring wells.
2. The proposed industrial supply wells may induce the inflow of relatively poor quality groundwater into a zone of relatively higher water quality within the water-supply aquifer beneath the Buttonwillow Service Area.
3. The project's pumping could exacerbate overdraft in the Kern County subbasin.
4. The project pumping could reverse local water level increases and increase the threat to the California Aqueduct from subsidence.
5. The project use of the proposed water supply may not be consistent with Energy Commission and other state water policies.
6. Staff cannot verify a persistent source of saline water flowing eastward towards the Buttonwillow Service Area.
7. Applicant dismisses potentially feasible water alternatives because proposed use is so high.

Therefore, staff proposes to investigate in more detail alternative cooling options in the FSA/FEIS.

The **Executive Summary Table 2** below illustrates Energy Commission staff's preliminary assessment of the proposed HECA project and also identifies the areas where staff has requested additional information. These preliminary conclusions are subject to change in the FSA/FEIS depending upon additional information received.

Executive Summary - Table 2
Environmental and Engineering Assessment

Technical Area	Complies with LORS	Impacts Mitigated	Additional Information Requested
Air Quality	Yes	Yes	**Yes**
Biological Resources	Undetermined	Undetermined	**Yes**
Carbon Sequestration and GHG Emission	Undetermined	Undetermined	**Yes**
Cultural Resources	Undetermined	Undetermined	**Yes**
Hazardous Materials	Yes	Yes	No
Land Use	Undetermined	Undetermined	**Yes**
Noise and Vibration	Yes	Yes	**Yes**

Technical Area	Complies with LORS	Impacts Mitigated	Additional Information Requested
Public Health	Yes	Yes	No
Socioeconomics	Yes	Yes	No
Soil and Surface Water Resources	Yes	Yes	**Yes**
Traffic & Transportation	Undetermined	Undetermined	**Yes**
Transmission Line Safety/Nuisance	Yes	Yes	No
Visual Resources	**No**	**No**	No
Waste Management	Undetermined	Undetermined	**Yes**
Water Supply	Undetermined	Undetermined	No
Worker Safety and Fire Protection	Yes	Yes	No
Facility Design	Yes	N/A	No
Geology & Paleontology	Yes	Yes	**Yes**
Power Plant Efficiency	N/A	N/A	**Yes**
Power Plant Reliability	N/A	N/A	**Yes**
Transmission System Engineering	Yes	Yes	**Yes**
Alternatives	N/A	N/A	No

ADDITIONAL INFORMATION THAT ENERGY COMMISSION STAFF REQUIRES FROM THE APPLICANT IN ORDER TO COMPLETE THE FINAL STAFF ASSESSMENT

Below is a list, arranged by technical area, of outstanding information staff requires prior to issuing an FSA/FEIS. Please refer specifically to each technical section for a detailed discussion and the context for which the information is required.

AIR QUALITY

A revised emissions estimate for HECA that matches the current project description, including but not necessarily limited to: the removal of the ammonia product shipping emissions; and the addition of the limestone fluxant. The revised emissions estimate should include the shipping, handling, and storage emissions from the fluxant and should address the shipping emissions for potential alternative shipping locations for the gasifier solids that have been provided to staff in other data responses.

Carbon Sequestration and Greenhouse Gas Emissions

A binding contract between SCS Energy LLC and Occidental of Elk Hills, Inc., provided to the Energy Commission, that:

1. Identifies the responsibilities of each party to demonstrate and document permanent sequestration of the supplied carbon dioxide.
2. Documents Hydrogen Energy California's rights to the entire carbon dioxide sequestration emissions reductions as necessary for SB 1368 EPS and other regulatory compliance.

3. Clearly states that the carbon dioxide sequestration emissions reductions shall not be used for any other purpose than providing for the compliance obligation needs for HECA.
4. Requires Occidental of Elk Hills, Inc. to provide a Carbon Dioxide Emissions Sequestration Plan to the Energy Commission for review and approval as detailed under the preliminary staff Condition of Certification **GHG-3**.
5. Clearly states the duration of the contract agreement.

Additionally, the applicant needs to provide:

1. A complete electrical energy balance estimate for HECA that includes the complete gross electrical production and complete parasitic load for the plant by major functional area, including the air separation unit, in MWh for both hydrogen rich fuel and natural gas operation. Staff cannot complete its determination of compliance with the SB 1368 EPS without this information.
2. A revised greenhouse gases emissions estimate for HECA that matches the current project description, including but not necessarily limited to: the removal of the ammonia product shipping emissions; the addition of the limestone fluxant shipping and use; and that addresses the shipping emissions for potential alternative shipping locations for the gasifier solids.
3. The District's FDOC that addresses staff's comments on the PDOC, specifically revising the combined-cycle power generating permit unit condition 86 to be based on the District's CO_2 BACT determination rather than the SB 1368 EPS.
4. Further information describing how OEHI would abate CO_2 if it leaks to the surface and escapes into the atmosphere.
5. Information detailing how the applicant would comply with the proposed allowable CO_2 venting hours without a back-up CO_2 injection zone.
6. Provide all of the following (some of the terms below such as "Power", Fertilizer" and "Common" refer to computations in the new material presented in spreadsheets provided by e-mail on May 10, 2013.):
    a. A carbon balance for HECA demonstrating the complete flow of carbon from the introduction of feedstock to the coal dryer to the products (including carbon dioxide [CO_2]) and waste streams. Please provide this carbon balance for both the oon- and ooff-Peak operating cases. This carbon balance should be more detailed than what was previously provided in the Amended AFC and data responses, clearly identifying the carbon in all the streams between major processes and process units where carbon flows changes.
    b. Detailed background information supporting the latest applicant- sponsored SB 1368 calculations. Please provide the following:
        - A detailed list of the project equipment indicating each piece of equipment's power consumption value; and

- Project equipment allocation (Power, Fertilizer or Common) for each listed piece of project equipment.

c. The gross and net megawatt (MW) assumptions for the three available ambient cases (39, 65 and 97 degrees F). Include the on-Peak, off-Peak and Daily Average categories.

d. Describe how the fertilizer power generation values, which appear to be different than the previously presented 5 MW value, were determined for the on-Peak and off-Peak cases.

e. Detailed calculations and rationale for the syngas allocation percentages allocated to power block and fertilizer in the HECA Power Generation for SB 1368 Emission Performance Standard Table for each project case (on-peak, off-peak, and Daily Average).

f. Detailed calculations and rationale for the calculations used to determine the syngas allocation to power and fertilizer that were used to determine the CO_2 emissions by emissions source. Please confirm this value is for the daily average case, and provide the values for the on-peak and off-peak cases.

g. Additional background information explaining the syngas allocation method used to determine CO_2 emissions from the fertilizer plant. This additional detail should explain the methodology sufficiently to ensure that CO_2 emissions from the fertilizer plant are not double counted when CO_2 emissions are sequestered in the urea produced.

h. The syngas allocation by section (see spreadsheet provided by applicant for May 10, 2013 meeting, attached to TN 70829) does not include a value for the common allocation. The CO_2 emissions from components identified elsewhere in the spreadsheet designated as "Common" are calculated using the power allocation percentage in the spreadsheet. Confirm or provide the correct common allocation percentage.

i. The air separation unit's power consumption value expected for the on-peak, off-peak on-peak, off-peak, and daily average cases. This can be presented with apportionment to the power block and fertilizer plant if detailed calculations and rationale for that apportionment basis (based on use of the produced oxygen and nitrogen and its later products, hydrogen and CO_2, used for power and fertilizer production) are provided.

j. The applicant stated that the power consumption for initial CO_2 compression that is completed at the HECA site was sufficient to provide CO_2 at a pressure necessary for geologic sequestration.

   - Confirm that means that the compression completed at the HECA site and the power consumed by the compressors on the HECA site is adequate to provide a level of compression that is sufficient to provide pressure necessary for geologic sequestration, or if the power consumption calculations include additional compression power consumption beyond that which is actually done at the HECA site that would be needed to obtain the desired pressure.

- Indicate if the assumed pressure necessary for geologic sequestration is the same pressure that is required by Oxy Elk Hills (OEHI) to inject the CO_2 into the Stevens formation.
- Indicate how much pressure is lost in terms of equivalent power consumption from the CO_2 custody transfer point to the point of receipt at the OEHI central EOR facility for initial injection into the oil reservoir.

k. A review of the emissions tables indicates that there are changes to some of the emissions calculation assumptions provided in Appendix E, such as the fuel consumption in the gas turbine and duct burners.

- Update Appendix E as necessary to include all of these changes as well as the other recent changes to the project (addition of fluxant, removal of ammonia export).
- Provide emissions calculations (AQ and GHG) for both the on-peak and off-peak cases clearly showing fuel flow to the combustion turbine and duct burners for each case.
- Show how HECA off-peak operations would impact other emission sources and provide information on changes to the major component stream flows that may occur during these operating conditions (such as, does amount of CO_2 shipped to OEHI go up during off-peak operations, or does the CO_2 concentration in the hydrogen rich fuel go up to maintain a constant CO_2 emissions profile for the HRSG and coal dryer stacks for on- and off-peak operations?).

l. Based on Table 2-10 provided in the Amended AFC, during maximum ammonia production, referred to as off-peak operation, production of the other fertilizer components do not increase.

- Provide data/calculations confirming the plant will have adequate ammonia storage facilities capable of handling the increased ammonia that would be produced during off-peak operations.
- Indicate if the rate of ammonia consumed by the plant varies with respect to the fertilizer products during on-peak and off-peak operations, and if so please provide the on- and off-peak operation case production rates for nitric acid, urea, and UAN production.
- Clearly indicate if HECA's ammonia use is higher than its production rate during on-peak operations, or if other components of fertilizer production, including the intermediate products like nitric acid, would increase with the increase in ammonia production during off-peak periods of operation.

m. Provide a detailed list of the monitoring and recordkeeping methods and procedures that are proposed to be used to demonstrate ongoing compliance with the SB 1368 emission performance standard (EPS) during facility operations. This should include:

- Monitoring methods and locations to establish CO_2 emissions from all onsite project sources, including fugitive emissions sources.
- Monitoring methods and locations to establish net electricity generation values for all electricity consumed and generated.
- Recordkeeping measures to ensure completeness and accuracy of data collected.
- Coordination with OEHI to obtain necessary data on carbon sequestration to support the value of the sequestered CO_2 that can be used to account for the amount of CO_2 shipped to OEHI.

n. As an adjunct to GHG, confirm the current planned and unplanned outage as the basis for reliability. Currently, our understanding is as follows:

- Planned: Two 1-week planned maintenance outages with 15-hour ramping allowance for 351 hours
- Planned: Two cold-start cycles, each 4 days long for a total of 192 hours
- Unplanned: 219 hours of outage based on 91.3% equivalent availability factor (EAF), calculated as follows: (1-0.913) x 8760 = 762 hours of total outage. 762 (hours of total outage) –351 (maintenance outage hours) – 192 (cold start-up hours) = 219 hours (unplanned outage hours).

BIOLOGICAL RESOURCES

1. Comprehensive mitigation strategy for project impacts to San Joaquin kit fox, giant kangaroo rat, Tipton kangaroo rat, San Joaquin antelope squirrel, blunt-nosed leopard lizard, Swainson's hawk, burrowing owl and HECA's incremental contribution to cumulative effects to these species that are covered in the *Recovery Plan of Upland Species of the San Joaquin Valley*. Specifically, identify which species and acreage the applicant is proposing to mitigate through purchase of mitigation credits from the Kern Water Bank and which species and acreages would be mitigated through offsite land acquisition. For offsite land acquisition, please identify the species-specific habitat criteria for offsite mitigation lands and cost estimates for determining security (eg. cost estimates for land acquisition, start-up activities and initial habitat improvements, funding during the three-year interim management period, and long-term management).
2. Additional focused protocol-level botanical surveys (CDFG 2009) along all linear routes and additional baseline botanical data, primarily the proposed carbon dioxide pipeline route;
3. Jurisdictional determination from CDFW regarding state waters (ephemeral drainages) in the project area, including all linear routes and ephemeral drainages that may occur along the proposed carbon dioxide pipeline route;

4. Jurisdictional determination from the U.S. Army Corps of Engineers Section 404 for the project area, including all linear routes and ephemeral drainages that may occur along the proposed carbon dioxide pipeline route;
5. Habitat mitigation strategy for habitat loss impacts from OEHI component of HECA at the Elk Hills Oil Field. Please identify whether species impacts including habitat loss for the OEHI component would be included under the Section 10 Habitat Conservation Plan currently under preparation or if habitat loss for the OEHI component of HECA would be mitigated under separate consultations with CDFW and USFWS;
6. Western spadefoot toad habitat assessment along project linear routes including upland refugia and aquatic habitats preferably during the wet season (defined as October 15 to April 15 of any given year) and following sufficient winter or spring rains in order to identify potential depressional areas and upland refugia that may provide habitat for western spadefoot toad. All potential ponding areas should be identified and mapped with a GPS unit including the single pond where this species was identified previously. Information to be collected at each mapped potential breeding area includes, but is not limited to: the specific numbering system of each potential breeding area, presence of tadpoles and species (if any), habitat community, microhabitat features, observed plant species, observed wildlife species including invertebrates, water temperature, approximate depth and surface area, and level of disturbance;
7. Vehicle-fox strike and incidental take analysis considering the project's contribution to existing traffic volumes and intersections of the proposed construction and operation routes with other linear right-of-ways that occur within and outside of San Joaquin kit fox core recovery areas. The applicant should calculate vehicle mortality rates to kit fox and other mammals over the life of the project; and
8. Water supply analysis and the effects of groundwater pumping to the sensitive vegetation communities and raptor nest trees which occur in the project area. The applicant must provide an analysis of the baseline groundwater levels and water source of raptor nest trees and alkali sink scrub habitat along HECA's linear routes, primarily the natural gas pipeline, processed water pipeline, and well field.

CULTURAL RESOURCES

For the EOR components: all of the information required for cultural resources in the Energy Commission Siting Regulations, Appendix B (20 Cal. Code Regs., §1704(b)(2), App. B).

1. Complete pedestrian survey results for all of HECA's linear alignments.
2. Results of test excavations and evaluations of CRHR/NRHP eligibility for all archaeological sites that staff has identified as having the potential to be directly impacted by HECA or OEHI.
3. Results of geoarchaeological field sampling.

LAND USE

A site plan drawn to scale of all proposed structures demonstrating compliance with the sections of the zoning ordinance cited above.

NOISE

Due to potential noise impacts to receptors from project-related traffic, soundwalls may be necessary along the truck route. Prior to preparing the FSA/FEIS, the applicant needs to inform staff of the potential locations of the soundwalls.

SOILS AND SURFACE WATER

Additional Information for the draft DESCP:

- Show all potential locations of horizontal directional drilling (HDD) activities in the DESCP and update the disturbed soil estimates of entry/exit pits. If HDD sites are not yet finalized, please be conservative and include all potential sites.
- Staff notes that some of the lined retention basins at the HECA site are calculated to have drawdown times that exceed the Kern County maximum of seven days (Kern County Hydrology Manual – Section 408.08.01). Please adjust the basin design and/or operations to comply with the Kern County basin standard. Also revise the DESCP and hydrology report to reflect these changes.

Proposed Rail Spur Impacts to Offsite Flooding:

- Maps and drawings that show locations where construction would cross drainages, canals, and other water bodies. Identify what local and/or permits would be required for these crossings.
- Description of typical methods proposed for accommodating flows under or around the rail bed. Include maps that show locations of drainage features and indicate what flows they would be designed to handle.
- Identify whether the rail bed would be constructed in or near a FEMA 100-year floodplain Zone A. If so, discuss the measures that would be required to ensure no upstream or downstream impacts.

TRAFFIC AND TRANSPORTATION

The applicant recently proposed adding storage of limestone and ammonium nitrate at the project site. These revisions would change the number of truck trips to and from the project site. Staff needs additional information from the applicant regarding how this revision in the number of truck trips could also change the potential impacts related to traffic and transportation. Specifically, staff requests the applicant provide revised truck trip numbers for both with the rail spur and without the rail spur and identify changes to the level of service (LOS) at intersections and roadway segments that would occur with the revised truck trips. This issue will be addressed in the FSA/FEIS.

Along with the revision to the on- site storage of limestone and ammonia nitrate used for the HECA project, staff has raised a question regarding the need to expand the Wasco coal servicing facility to serve the project's demand. Potential components of the coal servicing facility initially considered by staff include the possible need for additional storage silos and/or receiving lane for trains and/or haul trucks. Staff requests the applicant identify specific components that would need to be expanded at the coal servicing facility in Wasco. The project's potential demand for expanding the Wasco coal servicing facility will be addressed in the FSA/FEIS.

Under a proposed alternative, HECA would construct and operate a rail spur for delivery of fuel and products to and from the project site. Because the CPUC traditionally has jurisdiction over such facilities, staff will continue to coordinate closely with the CPUC to ensure appropriate design of the rail line for safe operation. In order to ensure that CPUC staff has sufficient information in order to assist in analyzing the proposal, the applicant must submit all the information otherwise required for a formal application pursuant to Title 20, California Code of Regulations, section 3.1 for all public at-grade rail crossings needed for the proposed rail spur. This information is outlined in the CPUC Rules of Practice and Procedure 3.7 to 3.11 under Section 1001 of the Public Utilities Code and should be submitted, to both the CPUC and Energy Commission staff.

Additionally, the applicant must provide an analysis discussing the need for each of the private at-grade crossings proposed, the potential risks involved in proposing this many private crossings in such a small area, and whether, upon further examination, any crossings can be eliminated. This analysis should also discuss potential impacts to the movement of farm machinery and equipment due to reducing the crossings, and should identify to what extent lands on either side of the proposed spur are owned and maintained by the same person or entity, and, thus, could possibly be impacted by reduced connectivity.

Waste Management

- Staff was not provided a breakdown of types and quantities of nonhazardous and hazardous waste that will be generated from the OEHI component of HECA to confirm that the project will not have an impact on Kern County landfills. This data would be needed for staff to complete an assessment of potential impacts
- Staff needs the results of waste characterization tests in accordance with Title 22, California Code of Regulations, Division 4.5, section 66262.10 on coal and petcoke mixes using the Mitsubishi gasifier in Japan using processing methods representative of those to be used for project operation. The purpose of the testing is to determine whether the gasification solids would be hazardous or non-hazardous. This information is needed to further evaluate how the waste can be disposed of and whether it is feasible to market the solids for other uses. The information should include a description of the waste stream, an evaluation of where the residual material is suitable for disposal, identification of facilities that would accept the volume of waste generated, a letter from the facility demonstrating they would accept the waste, and evidence the disposal of the waste would be in compliance

with Kern County waste disposal requirements. If the project owner proposes to market the solids for use as supplementary cementitious materials or other purposes, then a detailed report indicating what uses can be marketed and letters of intent from prospective purchases should be included.

- The project owner should enter into an agreement with DTSC for the purpose of fully characterizing and if necessary remediating the site property so that it is in the appropriate condition to allow for future use. In addition based on the type of agreement with DTSC the applicant should conduct the necessary site characterization to determine if site remediation is needed and if so what the scope of remediation would be prior to the FSA.

Staff needs information on additional waste streams that would result from the addition of the limestone fluxant such as total tons and cubic yards. The applicant shall also provide information on the increased amount of gasification solids in tons and cubic yards.

GEOLOGY AND PALEONTOLOGY

Limestone would be mined and transported to the site to be used as a fluxant to reduce sulfur emissions. Currently it is unknown where the limestone is being mined, the entity that permitted the mine's operation, the capacity of the mine's resource and the estimated consumption of limestone during the project's design life. Staff requests that this information be provided as its evaluation is necessary to complete the analysis for the completion of the FSA/FEIS.

POWER PLANT EFFICIENCY

1. Reconciliation of the 405 MW gross power generation originally submitted in the AFC and the 431 MW power level currently under discussion elsewhere in this document;
2. Update of the mass and energy balance for the *entire* project boundary that uses *all* contemporaneous conditions, including the enhanced oil recovery (EOR) field, air separation (ASU), and the introduction of calcium carbonate to the feedstock blend, based on the various MW ratings.
3. Identification and description of the major power block components, including the gasifier, based on the various MW ratings.

POWER PLANT RELIABILITY

The applicant has failed to assign an AF (availability factor) to the gasification system and ancillary systems upon which the power block is dependent. The applicant needs to assign this AF, demonstrate how it was derived, and explain how it affects the 91.3 percent AF assigned to the power block.

TRANSMISSION SYSTEM ENGINEERING

The Transition Cluster Phase II Interconnection Study Report (Phase II Study) for HECA.

Appendix 1 of Executive Summary
Response to Comments

HYDROGEN ENERGY CALIFORNIA

DATE	DOCUMENT	WEBLINK	General Opposition	Support for the Project	Air Quality	GHG	CO2 Sequestration & Oil Recovery	Purpose and Need	Alternatives	Project Description	Public Health	TLS/Nuisance/Transmission Systems Engineering/EMF-RF	Facility Design	Engineering Facility Reliability	Generating Efficiency	Haz Mat, Toxins, Safety	Waste Management	Pollution Prevention	Land Use/LORS	Geological Hazards	Soil/Agricultural Resources	Water Resources	Recreational Resources	Traffic, Trans & Air	Noise	Visual Resources	Cultural Resources	Consultation with Tribes	National Historic Preservation Act	Paleontological Resources	Socioeconomic/Growth Inducing/Property Values	Environmental Justice	Biological Resources/Endangered Species	Funding/Cost	Suggestions/Requests
10/21/2010	Parks and Rec, PSA Part 1	TN #58852			X											X								X	X	X	X								
1/10/2011	Kern County	TN #59460														X	X							X											
5/8/2012	DOE/NETL to SHPO Initiate Sect 106 Consultation	TN #65602																					X				X						X		
5/25/2012	SHPO response to DOE re: Consultation	TN #65607																					X				X						X		
5/25/2012	Federal Aviation Administration	TN #66029																	X					X											
6/7/2012	CVRWQCB Comment letter	TN #65731														X	X					X													
6/11/2012	Kern County Planning Letter to CEC	TN #65840																																	
6/11/2012	Kern County Planning Letter to HECA	TN #65837																																	
7/12/2012	Kern County Planning Development Dept.	TN #66243																	X																
7/12/2012	Kern Tax	TN #66244		X																															
7/26/2012	EPA Region IX	TN #66381			X		X	X									X	X	X	X	X	X	X				X	X				X			
9/1/2010	Kern County Waste Management	TN #66008														X	X																		
9/18/2012	SJVAPCD Correspondence	TN #67016			X	X																													
10/16/2012	State Parks, Techachapi District Ltr.	TN #67800																	X				X				X								
10/31/2012	Toxic Sub Control Board Consent Agreement	TN #68274														X	X			X	X	X										X			
12/10/2012	US EPA Ltr Re PSD permit	TN #68841			X													X																	
12/10/2012	US EPA Ltr Re PSD permit-SJVUAPCD	TN #68843			X													X																	
12/19/2012	PUC Proposed Rail Alignment	TN #68923																						X									X	X	
2/14/2013	San Joaquin Valley Air Pollution District PDOC	TN #69525			X	X																													
2/21/2013	SJVAPCD Letter	TN #69622			X																														
2/25/2013	Letter From Kern Co Advance Planning Division	TN #69650																	X																
3/1/2013	DOE Letter Regarding Proposed Schedule	TN #69749																																	
3/5/2013	Kern Co Objection to Schedule Modification	TN #69811	X																																
3/6/2013	Kern County Response to AFC	TN #69831			X				X							X	X		X		X	X													
3/14/2013	SJVAPCD Letter to Staff Status Report #5	TN #69917			X	X																													
3/14/2013	Shafter-Wasco Irrigation District	TN #69925																				X													
3/19/2013	Kern Co Planning Dept, WAC Cancellation	TN #69957																	X																

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3/22/2013	Buena Vista Water Storage Dist Response	TN #70025																				X													
4/4/2013	Kern Co Planning Dept Info Request	TN #70218																						X											
4/8/2013	SJVAPCD Notice of Extension	TN #70250																																	
4/26/2013	SJVAPCD Mitigation Agreement-Emissions	TN #70496			X	X																													
4/26/2013	DOE Letter to Parks and Rec	TN #70485																											X						
5/2/2013	US EPA Bio Assessment	TN #70659																															X		
5/6/2013	Kern Co and DOGGR Permitting	TN #70631					X																												
5/9/2013	US EPA-Determination of Compliance	TN #70732			X	X																													
5/17/2013	Notice of Public Hearing-Kern Co.	TN #70840																	X																
5/30/2013	Natural Resources Defense Council Comment	TN #71052			X				X																										
RESPONSE FROM CEC HECA TEAM																																			
TOTALS			1	1	8	3	1	1	1	0	0	0	0	0	0	4	5	3	7	2	3	6	4	3	0	0	4	1	0	0	0	2	3	1	0

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3/23/2012	AIR Data Requests	TN #64367			X		X															X												X	
5/11/2012	Concerned Neighbors of HECA	HECARES	X																																
6/13/2012	Sierra Club letter re: AFC	TN #65756																																	
6/29/2012	AIR Letter-June 29	TN #66072			X		X																	X											
7/12/2012	Kern County Farm Bureau, Inc.	TN #66242			X														X			X													
7/27/2012	AIR-Tom Frantz Letter	TN #66342	X		X	X												X				X		X										X	
7/27/2012	Sierra Club Scoping Comments	TN #66370			X		X			X	X						X	X	X	X		X		X											
7/28/2012	Kern Minority Contractors Association	TN #66401																														X			
8/3/2012	Sierra Club Data Request #1	TN #66429																																	
8/10/2012	Sam Ackerman Comment	TN #66543		X																															
9/18/2012	Kern Co. Farm Bureau P.T.I.	TN #66783																																	
9/18/2012	Sierra Club Status Report #1	TN #66966																																	
9/24/2012	Kern Co. Farm Bureau Objection	TN #67286	X																																
10/11/2012	Sierre Club Motion to Compel	TN #67239			X	X	X		X					X		X		X	X	X		X		X								X			
10/17/2012	Tehachipi Letter to CEC	TN #67800																					X				X						X		
10/23/2012	Kern County Sheriff's Office	TN #68040																																	
10/30/2012	Sierra Club Data Request #2	TN #68264			X																	X													
10/31/2012	Support from Buena Vista Water Dist	TN #68269		X																		X													
10/24/2012	AIR Letter-October 24	TN #68276																			X	X													
11/1/2012	TSC & DOE Corrective Action Agree	TN #68274														X	X			X	X	X												X	
11/2/2012	C. Romanini-WebEx Issue	TN #68312																																	X
11/2/2012	CHP Needs Assessment	TN #68222																						X											
11/2/2012	AIR Status Rpt & Data Requests	TN #68076	X				X		X		X					X		X	X		X	X					X							X	
11/2/2012	Sierra Club Status Report #2	TN #67843																																	X
11/2/2012	Ltr from Kern County Sheriff	TN #68040																													X				
11/2/2012	Ltr from Building Trades Council	TN #67427																						X							X				
11/7/2012	Bakersfield Chamber of Commerce	TN #68471		X			X																												
11/13/2012	C. Romanini Petition to Intervene	TN #68356																																	
11/13/2012	Correction to AIR Status Report	TN #68276																																	
12/19/2012	Sierra Club Status Report #3	TN #68929																																	

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12/20/2012	Sierra Club Motion to Ext Disc	TN #68942																																	
1/14/2013	C. Romanini Correction	TN #69126																																	
1/16/2013	Redacted Sierra Club DR Set 3	TN #68945		X													X																		
1/22/2013	Law Enforce Needs Assess-Sheriff	TN #69212																																	
1/22/213	Law Enforce Needs Assess-CHP	TN #69213																																	
3/1/2013	Sierra Club Status Report #5	TN #69742																																	
3/4/2013	AIR Status Update	TN #69776																																	
3/4/2013	HECA Neighbors Petition	TN #69773	X																																
3/4/2013	HECA Neighbors Status Report	TN #69788																																	
3/19/2013	HECA Neighbors, Brackish Water	TN #69950																				X													
3/25/2013	Trespass Email, Romanini	TN #70043																																	
4/5/2013	Sierra Club Ltr re: GreenAction	TN #70244																														X			
4/9/2013	HECA Neighbors Support Letter	TN #70253																																	
4/9/2013	Sierra Club Status Report #6	TN #70255																																	
4/10/2013	HECA Neighbors Status Report	TN #70258																																	
4/11/2013	AIR Status Report #6	TN #70272																																	
4/12/2013	AIR Audio Recording	TN #70249																																	
4/17/2013	HECA Neighbors Comments	TN #70378			X																														
4/26/2013	HECA Neighbors Mitigation Agree	TN #70529			X																														
4/26/2013	AIR Protest	TN #70501			X																														
4/26/2013	Sierra Club PM10 Modeling	TN #70503			X																														
5/8/2013	AIR PDOC Response	TN #70671			X																														
5/16/2013	YouTube Coal on Tracks	TN #70911																																	
5/29/2013	AIR PDOC and Mitigation	TN #71015		X	X																														
5/30/2013	Sierra Club Prelim Determination	TN #71051			X				X							X		X																	
6/12/2013	Kern County Staff Report	TN #71273																																	
6/14/2013	Sierra Club Status Report #7	TN #71277																																	

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RESPONSE FROM CEC HECA TEAM																																			
TOTALS			5	5	14	2	6	0	3	1	2	0	0	1	0	4	3	5	4	3	3	11	1	6	0	0	2	0	0	0	2	3	1	4	2

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6/20/2012	Trudy Douglass Comment-June 20	TN #65878			X						X																								
7/5/2012	Trudy Douglass Comment-July 5	TN #66096			X						X																								
7/12/2012	Trudy Douglass Comment-July 12	TN #66245					X									X																			
7/12/2012	Chris Romanini Comment-July 12	TN #66249									X											X		X											
7/16/2012	Richard O'Reilly Comment	TN #66504																																	X
7/16/2012	C. Harding Comment	TN #66250																																	X
7/16/2012	Chris Romanini Email Comment	TN #66258																																	X
7/19/2012	Linda Wilson Comment	TN #66503	X																																
7/19/2012	Maggie Mincher Comment	TN #66500	X																																
7/19/2012	Sarah Goatcher Comment	TN #66351																																X	
7/24/2012	Kathleen Fanucchi Parsa Comment	TN #66385					X													X															
7/26/2012	Chris Romanini Comment	TN #66382			X																X	X		X											
7/26/2012	Arthur Unger Comment	TN #66357			X	X															X														
7/26/2012	Brad Bittleston Comment	TN #66348			X																														
7/26/2012	Majorie Bell Comment	TN #66347			X																X	X													
7/26/2012	Dean Clason Comment	TN #66349	X		X		X																												
7/26/2012	Bonnie Kempner Comment	TN #66388			X																														
7/27/2012	Alfino Cavazous Comment	TN #66501	X		X																														
7/27/2012	Kendell Heck Comment	TN #66496			X																	X		X											
7/27/2012	Daniel Bell Comment	TN #66248			X		X																												
7/30/2012	Richard and Jan Wolfe Comment	TN #66386			X																	X		X	X										
7/30/2012	Beau Antongiovanni Comment	TN #66397	X																																
7/30/2012	Trudy Douglass Comment-July 27	TN #66389				X	X														X			X											
8/2/2012	Trudy Douglass Comment Letter	TN #66427			X		X				X					X		X																	
8/3/2012	Cindy Stiles Comment	TN #66497			X		X															X		X											
8/3/2012	Debbie Shepherd Comment	TN #66498	X		X																	X													
8/15/2012	Mark Romanini Comment	TN #66705			X																														
9/21/2012	Trudy Douglass Comment-Sept. 20	TN #67235	X		X																	X													
9/21/2012	LaRee Snow Comment-Sept. 20	TN #67236	X																																
9/21/2012	Chris Romanini Comment-Sept. 20	TN #67234	X																																
9/26/2012	Processes Unlimited Comment	TN #67309		X			X							X																					
9/26/2012	B. Willow Comment-Sept. 26	TN #67320	X																																
12/13/2012	C. Romanini Email Comment	TN #68871																	X		X														
2/25/2013	T. Douglass Comment	TN #69653																																	
2/25/2013	T. Douglass Comment	TN #69652																																	
3/25/2013	C. Romanini Email Comment	TN #70043																																	
3/26/2013	T. Douglass Comment	TN #70011																																	
3/26/2013	T. Douglass Comment on 2410 Rule	TN #70012																																	
4/4/2013	T. Douglass Comment	TN# 70210			X																														

HYDROGEN ENERGY CALIFORNIA

DATE	DOCUMENT	WEBLINK	General Opposition	Support for the Project	Air Quality	GHG	CO2 Sequestration & Oil Recovery	Purpose and Needs	Alternatives	Project Description	Public Health	TLS/Nuisance/Transmission Systems Engineering/EMF-R	Facility Design	Energy Facility Reliability	Generating Efficiency	Haz Mat, Toxins, Safety	Waste Management	Pollution Prevention	Land Use/LORS	Geological Hazards	Soil/Agricultural Resources	Water Resources	Recreational Resources	Traffic, Trans & Air	Noise	Visual Resources	Cultural Resources	Consultation with Tribes	National Historic Preservation Act	Paleontological Resources	Socioeconomic/Growth Inducing/Property Values	Environmental Justice	Biological Resources/Endangered Species	Funding/Cost	Suggestions/Requests
4/12/2013	Betty Foley Comment	TN #70283	X																																
4/12/2013	T. Douglass Comment	TN #70282																																	
4/15/2013	Jan Burnett Comment	TN #70313			X																														
4/18/2013	T. Douglass Emissions	TN #70379			X	X																													
4/23/2013	Karen Wright Complaint	TN #70433	X																																
5/6/2013	Pete Parson Comment	TN #70616	X																																
5/17/2013	C. Romanini Email Comment	TN #70859																																	
5/20/2013	Sarah Goatcher Comment	TN #70952																																	
5/23/2013	C. Romanini Email Comment	TN# 70940																																	
6/3/2013	Sarah Goatcher Comment	TN #71077																																	
RESPONSE FROM CEC HECA TEAM																																			
TOTALS			11	1	19	2	8	0	0	0	4	0	0	1	0	2	0	1	1	1	5	8	0	6	1	0	0	0	0	0	0	0	0	1	3

INTRODUCTION

PURPOSES OF THIS DOCUMENT

This Preliminary Staff Assessment and Draft Environmental Impact Statement (PSA/DEIS) is a joint document presenting the California Energy Commission and Department of Energy staffs' independent review and analysis of the Hydrogen Energy California project (HECA). The Energy Commission uses this document along with other information obtained during the course of the proceeding to decide whether to certify the HECA project; this certification is in lieu of any permit required by state, regional, or local agencies, and federal agencies to the extent permitted by federal law (Pub. Resources Code, §25500). The Warren-Alquist Act (Pub. Resources Code §25500 et seq.), Title 20, California Code of Regulations section 1701 et seq., and the California Environmental Quality Act (CEQA) (Pub. Resources Code, §21000 et seq.) guide Energy Commission staff in its analysis.

The U.S. Department of Energy (DOE) will use this document to inform its decision on whether to provide financial assistance for the construction and demonstration of the project; it must comply with the National Environmental Policy Act (42 United States Code [U.S.C.] §§ 4321 et seq.) in making this decision.

As the CEQA and NEPA processes are similar, the Energy Commission and DOE decided to cooperate in complying with the requirements applicable to each agency to the extent practicable in order to facilitate public involvement and conserve agency resources. CEQA encourages state agencies to combine environmental documents with federal agencies where possible and appropriate and Executive Order 13604 (Obama, March 22, 2012) directs federal agencies to avoid environmental reviews that are duplicative of reviews conducted by state agencies or other entities whenever possible. Preparation of a combined Preliminary Staff Assessment and Draft Environmental Impact Statement is consistent with this objective. Energy Commission staff and DOE also believe that this combined effort is in the best interest of stakeholders and interested parties, as it allows them to participate in a single, coordinated process, avoiding their needing to review multiple documents that contain similar information about the project. Accordingly, this document constitutes Energy Commission staff's PSA and DOE's DEIS. The Energy Commission and DOE worked closely with other agencies in preparing this PSA/DEIS – the U.S. Environmental Protection Agency, U.S. Fish and Wildlife Service, U.S. Army Corps of Engineers, California State Lands Commission, State Water Resources Control Board/Regional Water Quality Control Board, California Department of Fish and Wildlife, the California Air Resources Board, and Kern County.

While each agency has distinct missions and regulatory requirements, the proposed project, the affected environment, and the potential impacts are the same. Accordingly, the sections of this document that deal with these topics do not contain specific reference to a particular agency. On the other hand, this document contains separate sections discussing each agency's mission, the alternatives it must consider, the regulatory requirements applicable to it, and the decisions it will make based on the information in this document, as these are different for the Energy Commission and DOE. Both NEPA and CEQA share the goal of ensuring government agencies make informed decisions regarding proposed actions subject to their jurisdiction.

For the Energy Commission, this PSA/DEIS is a staff document; it is neither a Committee document, nor a draft decision. The Energy Commission Committee overseeing the project will hold evidentiary hearings, then prepare a Presiding Member's Proposed Decision, which will be presented to the full Energy Commission for a vote to approve or deny that proposed decision. For DOE, this PSA/DEIS serves as a NEPA document; it will be followed by a Final Environmental Impact Statement. At this time, DOE anticipates that the Final Environmental Impact Statement would be issued in conjunction with the Energy Commission's Final Staff Assessment. If DOE decides to provide financial assistance for construction of the HECA project, this will be followed by a Record of Decision (ROD).

The PSA/DEIS describes the following:

- the proposed project;
- the project alternatives (which may be somewhat different for each agency as a result of their differing roles and statutory regimes);
- the existing environment;
- whether the project's facilities can be constructed and operated safely and reliably in accordance with applicable laws, ordinances, regulations and standards (LORS);
- the environmental consequences (impacts) of the project including potential public health and safety impacts;
- the potential cumulative impacts of the project in conjunction with other existing and reasonably foreseeable developments;
- mitigation measures proposed by the applicant, Energy Commission staff, DOE, other interested agencies, local organizations, the public, and intervenors that may lessen or eliminate potential impacts; and
- the proposed conditions under which the project should be constructed and operated if it is certified by the Energy Commission and provided financial assistance by DOE.

The analyses in this PSA/DEIS are based upon information from the: (1) Amended Application for Certification (AFC), (2) responses to data requests, (3) supplementary information from local, state, and federal agencies, interested organizations and individuals, (4) existing documents and publications, (5) independent research, and (6) comments from the public. The analyses for most technical areas include proposed conditions of certification; some may also include mitigation measures DOE could impose as a condition of it providing financial assistance. Each proposed condition of certification is followed by a proposed means of "verification." This document presents preliminary conclusions about potential environmental impacts and conformity with

LORS, as well as proposed conditions that apply to the design, construction, operation and closure of the facility.

This document was prepared in accordance with Public Resources Code section 25500 et seq. and Title 20, California Code of Regulations section 1701 et seqCEQA (Pub. Resources Code, § 21000 et seq.), NEPA (42 U.S.C. § 4321 et seq.), the regulations implementing NEPA promulgated by the Council on Environmental Quality (CEQ) (Title 40, Code of Federal Regulations [C.F.R.] Parts 1500–1508), and DOE's NEPA procedures (10 C.F.R. Part 1021).

ORGANIZATION OF THE DOCUMENT

Resource areas are examined in individual sections and are followed by a discussion of project construction, operation, and required conditions of certification for each resource analyzed. In addition there are a set of standard Energy Commission requirements that apply to the project called "General Conditions". These contain the facility closure plans. At the end of the document there is also a list of the Energy Commission staff that assisted in preparation of the document.

Each of the resource assessments includes section authors and a discussion of:

- laws, ordinances, regulations and standards (LORS);
- the regional and site-specific setting;
- project specific and cumulative impacts;
- mitigation measures;
- conclusions and recommendations; and
- conditions of certification (and perhaps mitigation measures) for both construction and operation (if applicable).

ENERGY COMMISSION SITING PROCESS

The Energy Commission has the exclusive authority to certify the construction, modification and operation of thermal electric power plants 50 megawatts (MW) or larger in California. The Energy Commission certification is in lieu of any permit required by state, regional, or local agencies, and federal agencies to the extent permitted by federal law (Pub. Resources Code, § 25500). The Energy Commission must review power plant AFCs to assess potential environmental impacts including potential impacts to public health and safety, potential measures to mitigate those impacts [Pub. Resources Code, § 25519), and compliance with applicable governmental laws or standards (Pub. Resources Code, § 25523 (d)].

The Energy Commission's siting regulations require staff to independently review the AFC and assess whether the list of environmental impacts contained is complete, and whether additional or more effective mitigation measures are necessary, feasible and available [Cal. Code Regs., tit. 20, §§ 1742 and 1742.5(a)]. In addition, staff must assess the completeness and adequacy of the measures proposed by the applicant to ensure compliance with health and safety standards, and the reliability of power plant operations [Cal. Code Regs., tit. 20, § 1743(b)]. Staff is required to develop a compliance plan (coordinated with other agencies) to ensure that applicable laws, ordinances, regulations and standards are met [Cal. Code Regs., tit. 20, § 1744(b)].

Staff conducts its environmental analysis in accordance with the requirements of CEQA. No additional Environmental Impact Report (EIR) is required because the Energy Commission's site certification program has been certified by the California Resources Agency as meeting all requirements of a certified regulatory program [Pub. Resources Code, § 21080.5 and Cal. Code Regs., tit. 14, § 15251 (j)]. The Energy Commission is the CEQA lead agency.

The staff prepares a PSA that presents for the applicant, intervenors, organizations, agencies, other interested parties and members of the public, the staff's analysis, conclusions, and recommendations. Where it is appropriate, the PSA incorporates comments received from agencies, the public and parties to the siting case, and comments made at the workshops.

Staff will provide a comment period to resolve issues between the parties and to narrow the scope of adjudicated issues in the evidentiary hearings. During the period after the publishing of the PSA, staff will conduct one or more community workshops to discuss its findings, proposed mitigation, proposed compliance-monitoring requirements, and acquire the missing information needed for a final analysis. Based on the workshops and written comments, staff may refine its analysis, correct errors, and finalize conditions of certification to reflect areas where agreements have been reached with the parties, and publish a Final Staff Assessment (FSA).

The FSA is only one piece of evidence that will be considered by the Committee (two Commissioners who have been assigned to this project) in reaching a decision on whether or not to recommend that the full, five-member Energy Commission approve the proposed project. At the public hearings, all parties will be afforded an opportunity to present evidence and to rebut the testimony of other parties, thereby creating a hearing record on which a decision on the project can be based. The hearing before the Committee also allows all parties to argue their positions on disputed matters, if any, and it provides a forum for the Committee to receive comments from the public and other governmental agencies.

Following the hearings, the Committee's recommendation to the full Energy Commission on whether or not to approve the proposed project will be contained in a document entitled the Presiding Member's Proposed Decision (PMPD). Following publication, the PMPD is circulated in order to receive written public comments. At the conclusion of the comment period, the Committee may prepare a revised PMPD if necessary. At the close of the comment period for the revised PMPD, the PMPD is submitted to the full Energy Commission for a decision.

DOE NEPA PROCESS

DOE proposes to provide federal financial assistance to the applicant for its proposed project ("HECA" or "the project"), which would demonstrate integrated gasification combined cycle (IGCC) technology with carbon capture in a new electricity generating plant. DOE does not have regulatory jurisdiction over the project, nor would it own or operate the project. Its decisions are limited to whether and under what circumstances it would provide financial assistance for the construction and demonstration of the project. After the demonstration period called for in DOE's financial assistance agreement with the applicant -- which would last for two years once the project is in operation – DOE would have no further role in funding or other aspects of the project.

This DEIS describes the potential environmental impacts associated with DOE's proposed action (providing financial assistance), the project itself (including aspects of the project that DOE would not fund), and alternatives to and options for the project, including the No Action Alternative. Public comments will be solicited and considered prior to the development of the final environmental impact statement (FEIS).

DOE will use the NEPA process to inform its decision on whether to provide financial assistance for construction and demonstration of the project and, if so, whether it should impose environmental mitigation measures as a condition of its financial assistance for these activities. DOE's decisions will be announced in a Record of Decision (ROD). The Council on Environmental Quality's (CEQ) NEPA regulations require that DOE wait at least 30 days after the publication of an FEIS before it issues a ROD. DOE anticipates that it would not issue a ROD for HECA until after the Energy Commission's Presiding Member's Proposed Decision has been published, and possibly until the full Energy Commission votes to determine whether the project will be approved.

INTEGRATION OF THE NEPA AND CEQA PROCESSES

Energy Commission staff and DOE have integrated the environmental review processes required under CEQA with those required under NEPA. This PSA/DEIS is one aspect of that coordination. The agencies anticipate that they will prepare and issue a second coordinated document that would constitute the FSA and FEIS. After that the agencies anticipate that they will proceed independently in making their respective decisions regarding the HECA project. As noted above, DOE anticipates it will wait for the Energy Commission's Presiding Member's Proposed Decision, or possibly the final Commission Decision, before issuing a Record of Decision.

PROJECT DESCRIPTION

John Heiser

INTRODUCTION

In September of 2011, SCS Energy California LLC (SCS Energy) acquired the Hydrogen Energy California (HECA) project from BP Alternative Energy North America Inc., and Rio Tinto Hydrogen Energy LLC. Because SCS Energy intended to make several modifications to the project – including the addition of fertilizer production capabilities – the National Environmental Policy Act (NEPA) and the California Energy Commission's regulatory processes were suspended until HECA submitted the Amended Application for Certification to the Energy Commission on May 2, 2012.

HECA, if approved, would be partially funded by the U. S. Department of Energy (DOE) as a demonstration project under the Clean Coal Power Initiative Round 3 (CCPI-3). The CCPI-3 solicitation sought projects that would demonstrate advanced coal-based electricity generating technologies which capture and sequester (or put to beneficial use) carbon dioxide emissions. The HECA project was selected in the first phase of Round 3. The agreement with DOE includes possible funding support through the design, construction and the first two years of commercial operations.

SCS Energy California, LLC, the new owner of Hydrogen Energy California, LLC, submitted an Amended Application for Certification (AFC) to the Energy Commission on May 2, 2012. Public Resources Code section 25540.6 exempts certain types of projects from filing a notice of intention prior to filing an application for certification. This project qualifies for such an exemption as a "thermal powerplant designed to develop or demonstrate technologies which have not previously been built or operated on a commercial scale" pursuant to subsection 25540.6(a)(5). Pursuant to this exemption, the project may not exceed 300 megawatts unless the Energy Commission has authorized a greater capacity pursuant to regulation. As of the date of publication of this document, the Energy Commission has not authorized a greater capacity. HECA LLC is proposing to construct and operate a polygeneration project. HECA would use Western sub-bituminous coal, most likely from New Mexico mines, and petroleum coke (petcoke) from southern California refineries as the basis for producing the synthetic gas (syngas) fuel source for the project. HECA would comprise an advanced integrated gasification combined cycle (IGCC) power plant. The gasification process would rely on a Mitsubishi Heavy Industries oxygen-blown dry feed gasifier, designed to convert petroleum coke and coal into a carbon dioxide and hydrogen-rich synthesis gas (syngas) which would fuel a combustion turbine unit. Through a complex process, mercury, sulfur, hydrogen sulfide and carbon dioxide would be removed from the syngas leaving a hydrogen rich fuel for the combustion turbine. By directing steam produced in this process to a heat recovery steam generator (HRSG) that is connected to the shaft powering the generator, HECA would produce up to 300 megawatts of net electrical output to the grid. The proposed manufacturing complex would produce approximately one-million tons per year of ammonia and nitrogen-based fertilizer products. The plant would produce low carbon ammonia-based agricultural fertilizers by diverting hydrogen and carbon dioxide produced from the gasification process, and nitrogen from the air separation unit, to the manufacture of urea pastilles and urea-ammonium nitrate; both products are agricultural fertilizers. Intermediate products produced to make fertilizer products, but not be sold as products, include anhydrous ammonia and nitric acid.

Additionally, approximately 90 percent of the carbon dioxide ($C0_2$) produced by HECA, estimated to be about 3 million tons per year, would be captured. Approximately 2.6 million tons would be compressed and sent through a three-mile long, 12” diameter pipeline to the Occidental Elk Hills Oil Field $C0_2$ enhanced oil recovery (EOR) Processing Facility where it will be conditioned, and distributed to satellite locations and then to injection wells as part of an on-going enhanced oil recovery project. The CO_2 would be a key component of a water-alternating-gas process that displaces and moves oil and gas from the pore-spaces to the production wells and would result in the eventual sequestration (permanent geologic encapsulation) of the injected CO_2 within the reservoir’s vacated pore-spaces. Approximately 0.4 million tons of CO_2 per year would be used in fertilizer production and not considered to be sequestered. HECA would be expected to have a 25 year life span, and Occidental Elk Hills, Incorporated (OEHI) EOR project would use the CO_2 from HECA for the life of the HECA project (see the **Sequestration and Greenhouse Gas** section of this document).

HECA has proposed two coal transportation alternatives: Alternative 1 is a proposed 5-mile private railroad spur that would connect with the existing San Joaquin Valley Railroad at Buttonwillow to HECA. Alternative 1 would allow for the delivery of coal and the possible transportation of the proposed manufactured products to commercial markets. Alternative 2 would involve transportation of the coal to HECA from the coal transloading facilities in Wasco using trucks, an approximately 27-mile route. Manufactured product would also require truck transport from the project site under Alternative 2. (**Project Description Figures 6, 7,** and **9**).

During construction traffic would range as high as 1230 vehicle round trips per day, with an additional 50 truck deliveries, and 60 soil deliveries to the site. During operations (post-construction) expected traffic levels were estimated for each of the two alternatives. Alternative 1, would likely have 154 vehicle round trips per day for operations staff, 213 truck round trips for process material (fertilizers) and 175 truck round trips for feed stock deliveries (predominantly petcoke and fluxant). Alternative 2 would have 154 vehicle round trips, 399 truck round trips for process materials, and 910 truck round trips delivering feed stock (coal, petcoke and fluxant). The **Traffic and Transportation** and the **Land Use** sections of this document discuss these elements in more detail. Staff also analyzes the associated impacts from each transportation alternative further in the **Air Quality**, **Public Health**, and **Noise** sections of this document.

HECA proposes to use Mitsubishi Heavy Industries equipment to gasify petroleum coke (petcoke) from southern California refineries, bituminous coal from mines in New Mexico and limestone fluxant from California sources, producing a hydrogen-rich synthesis gas (syngas) to be used in a combustion turbine and a steam turbine to drive a single-shaft generator producing between 405 and 431 megawatts (MW) of gross base-load electricity, with up to 300 MW net electrical output, and would connect to the Pacific Gas and Electric (PG&E) 230kV transmission network at a new switchyard to be constructed approximately 2 miles east of the project site. The proposed transmission line would be approximately 2.8 miles in length from the on-site switchyard at the northwest portion of the project, with 0.8 miles of the line traversing eastward across the HECA site and buffer area.

HECA would gasify an approximately 75 percent coal and 25 percent petcoke fuel blend to produce synthesis gas (syngas) that would be processed and purified to produce a hydrogen-rich gas; the syngas would be used to fuel the combustion turbine and the burners that provide supplemental fire to the heat recovery steam generator (HRSG). The HRSG produces steam from the combustion turbine exhaust heat.

The Mitsubishi Heavy Industries (MHI) gasification system selected for this project produces a synthetic gas that is further processed and cleaned to produce both CO_2 and a hydrogen-rich fuel used for power generation and ammonia synthesis to be used at the manufacturing complex, where the syngas would also be used in the manufacturing of low-carbon ammonia-based agricultural fertilizer products in the integrated manufacturing complex. **Project Description Figure 3** displays the principal features of the gasification, power generation, and manufacturing facilities proposed for HECA.

HECA would capture up to 90 percent of the CO_2 produced from these processes, then compress and send this via an approximately 3-mile pipeline to a facility to be developed by Occidental Petroleum Elk Hills, Inc. (OEHI) for use in a planned enhanced oil recovery (EOR) project. HECA would capture approximately 3 million tons sequestering about 2.6 million tons of CO_2 annually for aiding in increasing oil production and eventual geologic sequestration in the Stevens Reservoir of the Occidental Elk Hills Oil Field (EHOF). The EHOF is owned and operated by Occidental Elk Hills, Inc. (OEHI) (**Project Description Figures 4 and 10**). The OEHI EOR project would apply separately for the required permits through the Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR), and has provided initial information and begun discussions with that agency. Additional permits may also be required for certain project elements, such as roads, through Kern County requirements.

The CO_2 EOR Processing Facility would be located approximately 3-miles south of the HECA property, inside the EHOF (**Project Description Figure 10**). The Processing Facility and 13 satellites would be expected to occupy approximately 136 acres within the EHOF and located approximately 3-miles south of the HECA property. The facility would use approximately 720 producing and injection wells, 570 existing wells and 150 new well installations. Approximately 652 miles of new pipeline would also be installed in the EHOF during the 20-year proposed phase of the EOR project. Should HECA be approved, and begin operations, OEHI could extend the planned use of CO_2 in the EHOF's EOR process (HECA 2012a, Vol. I, Appendix A).

PROPOSED CONSTRUCTION TIMELINES

Project construction milestones have been affected by delays in the application process. The projected milestones below are based upon an approximately 7-month delay from those projected by the applicant in the May 2, 2012, AFC (Vol. I, page 2-11):

Table 1: Proposed HECA Construction and Commercial Operation Timeline

Commence preconstruction, construction activities	January 2014
Commence truck deliveries and ground disturbance	March 2014
Completion of construction	September 2017
Commence pre-commissioning activities	September 2016
Commencement of commercial operation	April 2018

PROJECT LOCATION AND JURISDICTION

As proposed, HECA would be located on a total of approximately 1,106 acres of privately-owned land in western unincorporated Kern County, California. The IGCC and the manufacturing complex and storage facilities, as well as the proposed coal, petcoke and fluxant storage facilities would be on 453-acres, with 653 acres adjacent to the project site allowing for a large buffer area with controlled access (**Project Description Figures 2, 3, 5** and **8**).

HECA would be located 20 miles west of the city of Bakersfield. It is 1.5 miles northwest of the unincorporated community of Tupman, and approximately 4 miles southeast of the unincorporated community of Buttonwillow. The project site address is 7361 Adohr Road, Buttonwillow CA 93106 (**Project Description Figure 1**).

The California State Water Project aqueduct lies to the south, and the Elk Hills Oil Field boundary is located approximately 1 mile south of the project site (**Project Description Figure 4**).

The western border of the Tule Elk State Natural Reserve (California state park) is located approximately 1,700 feet to the east of the project site. The nearest single-family dwellings are currently located approximately 370 feet to the northwest, 1,400 feet to the east, 3,300 feet to the southeast, and 4,000 feet to the north of the proposed project site (**Project Description Figure 5**). HECA has an option to purchase the dwelling in the northwest area of the project site (noted as 370 feet to the northeast).

The HECA site is located within Section 10 of Township 30 South, Range 24 East in Kern County. The project site Assessor's Parcel Numbers (APNs) are part of 159-040-02, part of 159-040-16, and part of 159-040-18.The proposed controlled area APNs consist of all of 159-040-04, all of 159-040-11, all of 159-040-17, all of 159-190-09, remnant part of 159-040-02, remnant part of 159-040-16 and remnant part of 159-040-18.

Kern County would require merging the parcels for the proposed project as part of the county's approval process, the Energy Commission would require compliance with this requirement (see the **Land Use** Section of this document).

Current and Adjacent Land Use

The proposed facility site is currently in agricultural production including cultivation of cotton, alfalfa and onions and an approximately 72-acre tract is currently subject to a Williamson Act agricultural land preservation contract; the applicant is pursuing a contract cancellation with Kern County and a hearing scheduled for June 13, 2013, regarding this parcel. The buffer area is proposed to remain in agricultural use. Land use in the vicinity of the project site is primarily agricultural with almond, pistachio, grapes, tomatoes, corn, onions and alfalfa crops.

The West Side Canal (and the Outlet Canal, Kern River Flood Control Channel (KRFCC), and the California Aqueduct (State Water Project) are approximately 500, 700, and 1,900 feet south of the project site, respectively (See **Project Description Figures 5 and 10**).

State and Federal Jurisdiction

The Energy Commission has exclusive permitting jurisdiction for the siting of thermal power plants of 50 MW or more and related facilities in California. The Energy Commission also has responsibility for ensuring compliance with the California Environmental Quality Act (CEQA) through the administration of its certified regulatory program and is the lead agency under CEQA. Additionally, under CEQA, the Energy Commission must conduct an environmental review of the "whole of the action," which may include facilities not licensed by the Energy Commission (California Code of Regulations, title 14, §15378). As a result, the Energy Commission analysis includes an environmental analysis of the proposed Occidental Elk Hills, Incorporated (OEHI) enhanced oil recovery (EOR) project that would be located within the Elk Hills Oil Field (EHOF). This EOR project and the related infrastructure would be the responsibility of the Department of Conservation, Division of Oil, Gas and Geothermal Resources (DOGGR) as Lead Agency. This PSA/DEIS analyzes the proposed EOR as a part of the project, or the whole of the action, pursuant to CEQA.

This PSA/DEIS provides initial analysis of these elements and facilities as part of its CEQA responsibility. The analysis regarding the EOR process and the permitting expectations is discussed in **Land Use, Air Quality, Sequestration and Greenhouse Gas, Socioeconomics, Biological Resources**, and other technical sections of this document.

This Preliminary Staff Assessment/Draft Environmental Impact Statement (PSA/DEIS) is being prepared as part of the coordinated Energy Commission and Department of Energy joint review process. Comments on this document, along with new information gathered by staff, will be included in a Final Staff Assessment/Final Environmental Impact Statement (FSA/FEIS).

Agency Coordination

Energy Commission staff, in cooperation with the Department of Energy, are coordinating with a wide range of federal and state agencies for the analysis of HECA. A brief summary of these efforts follows:

The Department of Energy (DOE) will issue joint documents with Energy Commission staff through the Final Staff Assessment and Final Environmental Impact Statement (FSA/FEIS) prior to issuing the federally-required Record of Decision (ROD) for the proposed HECA. The Amended Notice of Intent (ANOI) was published by DOE in the *Federal Register* on June 19, 2012 (77 FR 36519).

The U.S. Fish and Wildlife Service (USFWS), and the California Department of Fish and Wildlife (CDFW) are working with staff and with the DOE, and HECA, LLC regarding the biological analysis as well as the development of the required Biological Opinion, which will cover HECA and also the OEHI enhanced oil recovery project (EOR) that is planned within the OEHI's Elk Hills Oil Field (EHOF). The EOR would utilize approximately 3 million tons per year of the CO_2 produced by HECA, expecting that the project will result in sequestration of the CO_2 in permanently in the pore space vacated by the produced oil and gas. (See the **Biological Resources** and the **Sequestration and Greenhouse Gas** sections of this PSA/DEIS).

The DOE also has a responsibility under Section 106 of the National Historic Preservation Act to consult with the Native American tribes affected by HECA. This required effort parallels the requirement of the Energy Commission under the terms of the California Environmental Quality Act (CEQA). Efforts include coordination with the California State Historic Preservation Office (SHPO) to insure identification of the appropriate tribal entities, interested Native American individuals, and the possible location of important cultural resources in the vicinity of the proposed project. For detailed information on the process and the status of these efforts please see the **Cultural Resources** section of this document.

Coordination with Kern County will continue through this process, and through construction and operations should the project be approved. Through the efforts of the Kern County Planning and Community Development Department (PCDD) the Energy Commission staff and the applicant have independently sought clarification of the laws, ordinances, regulations and standards (LORS) which would govern the permitting of HECA but for the exclusive jurisdiction of the Energy Commission for powerplant applications proposing capacity of 50 MW or greater. The PCDD continues to provide input to staff, attending Energy Commission workshops and working with the Kern County Board of Supervisors to provide information on the County's LORS and recommended mitigation necessary to insure protection of the health and safety of the County residents. This input to date is reflected in the **Socioeconomics, Land Use, Traffic and Transportation**, and the **Worker Safety and Fire Protection** sections of this document.

The San Joaquin Valley Air Pollution Control District (SJVAPCD) issued a Preliminary Determination of Compliance (PDOC) on February 7, 2013, held a public workshop in Bakersfield on April 2, 2013, and scheduled a second PDOC workshop held in Buttonwillow on May 17, 2013, with a comment period closing on May 30, 2013. Work with the SJVAPCD continues throughout the process, and this also requires coordination with the California Air Resources Board (CARB) and the U.S. Environmental Protection Agency (EPA). For a complete description of these efforts please see the **Air Quality** and the **Sequestration and Greenhouse Gas** sections of this document.

The Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR) is coordinating with OEHI to review OEHI's Class II permit applications for the first phase of its CO_2 EOR proposal. DOGGR is still in the process of obtaining sufficient information regarding the proposal in order to deem the application complete and begin substantive evaluation. It is not likely that DOGGR will have made substantial permitting progress prior to Energy Commission and DOE action on a final Decision and Record of Decision. (See the **Sequestration and Greenhouse Gas** section of this PSA/DEIS).

California State Department of Parks and Recreation, Tehachapi District, Tule Elk State Natural Reserve is monitoring the project, and has provided staff with initial comments and planning its participation as the process moves forward. (See the **Biological Resources** section of this document).

The California State Water Board and the Regional Water Quality Control Board continue to provide information to staff, both agencies participated in the water supply workshop that was held in Sacramento on February 20, 2013.

General Agency Coordination: Staff continues to work with U.S. Environmental Protection Agency (U.S.EPA) staff to host a monthly agency roundtable discussion regarding HECA. The goal is to insure that agencies are kept apprised of the schedule for the project and that agencies may discuss regulatory and process concerns within the agency context. State and federal agencies have continued to make this forum a valuable source for information.

PROJECT DESCRIPTION, DESIGN AND OPERATION

This section describes HECA's conceptual design and various aspects of its proposed operation; **(Project Description Figure 3** shows the Site Plan and on-site project components**).**

FEEDSTOCK STORAGE, DRYING AND THE GASIFICATION UNIT

The petroleum coke and coal feedstock would be stored in separate piles inside a large storage building where it would be blended at a set rate and sent via an enclosed transfer conveyor system to the gasification system. The MHI oxygen-blown gasifier is a two stage design resulting in the production of syngas composed of mainly of (hydrogen and carbon monoxide. A complex syngas treatment system further refines the product prior to its use as fuel for the turbine and chemical plant. Steam produced as the syngas is cooled in this process is directed to the heat recovery steam generator (HRSG) to assist in power generation. The gasification system consists of equipment used to grind and dry the feedstock prior to its entering the two-stage MHI gasifier. The limestone fluxant is added to the feedstock as it moves to the gasifier. Feedstock would enter the gasifier at two stages. One stream is fed into the first stage of the gasifier and oxygen is added. In this lower first stage the feedstock and oxygen are gasified at high heat, sufficient to melt the coal ash, and producing carbon monoxide (CO), H_2, CO_2 and other trace components. The molten coal ash flows down a protective membrane and is quenched in a water bath and then removed via a lock hopper system. The gas produced in the first stage rises to the second stage where the second stream of feedstock enters but no additional oxygen is added. In this second stage the gasification of char to CO occurs. The syngas produced in this stage exits through a syngas cooler, generating steam. This steam is directed to the heat recovery steam generator (HRSG) and used for power generation. Downstream a cyclone and a filter collect the char and recycle the char back to the lower stage of the gasifier to increase the overall carbon conversion efficiency.

The syngas leaving the second stage is at approximately 2200 degrees Fahrenheit, which helps insure that negligible hydrocarbon gases and liquids are formed. This raw syngas would now go through an additional complex series of treatment processes including scrubbing to remove chlorides, minimizing potential for forming ammonium chloride inside downstream equipment as the syngas cools.

There are several complex downstream systems associated with processing the raw syngas so that it would become suitable to fuel the combustion turbine. Processes downstream remove sulphur, and in a Sour Shift Unit, the remaining CO and water go through a water-gas shift reaction which produces CO_2 and hydrogen (H_2). Additional systems remove mercury, acid gases (in a patented Rectisol® system) including hydrogen sulfide and CO_2.

POWER BLOCK CTG AND THE HRSG UNIT

A cold startup of the coal gasifier and transitioning to start up of the combustion turbine and electrical generation system would begin with processing (grinding and drying) of the coal and blending with the petcoke and loading to the gasifier for production of the syngas. The syngas would be routed to the CTG and the HRSG. During startup operations the combustion turbine generator (CTG)/heat recovery steam generator (HRSG) would be fired on natural gas and would transition to the hydrogen-rich fuel (syngas) approximately two and a half hours into the transition process. A startup sequence of the CTG and HRSG operating on natural gas is estimated to require approximately 4.5 hours. A complete system (CTG, HRSG, and gasification system) shutdown sequence is estimated to take 9 hours. The combined cycle power block would generate between 405 and 431 MW. The applicant's engineering team continues to work with the MHI engineering group and results of the final design may increase the efficient use of process excess heat, which may result in increasing the gross CTG output to the higher value. The applicant expects that HECA would be providing baseload electricity using the syngas produced from the project's gasification unit. The power generation equipment is similar to conventional natural gas power plants; however, there is substantial heat integration with the gasification process where heat is recovered as useful energy for additional power generation. The combined cycle block would include a single-shaft MHI 501GAC® G-class, air-cooled combustion turbine/steam turbine generator configured to operate using hydrogen-rich fuel.

The power block also would include a heat recovery steam generator (HRSG) and a water cooled surface condenser. Exhaust gas from the turbine as well as supplemental hydrogen-rich fuel and other process off-gas for duct-firing would be sent to the HRSG to generate additional electricity. The HRSG would be equipped with emission control technology to reduce stack emissions. The HRSG would include a selective catalytic reduction system (SCR) to meet best available control technology (BACT) requirements for nitrogen oxides (NOx). The SCR system would use ammonia injected upstream of the SCR catalyst. The SCR catalyst would be used to convert NOx and ammonia into nitrogen and water.

Proposed Operation of HECA

HECA is designed to balance power production, CO_2 capture and use, and fertilizer manufacturing plant output. The electrical output and availability of maximum electricity production is, in part, balanced with the maximum manufacturing output. HECA, in the AFC, has proposed that the balance would be approximately 16 hour per day at 405 MW, (per amended AFC application) when maximum electricity production may be needed; and 8 hours per day at 295 MW during hours when maximum fertilizer and ammonia production would be possible due to lessened demand for the electrical output.

The HECA assumption is that this variability provides an optimum balance for the combined operations. HECA also assumes that products that would result from operations of the above systems may have commercial value. These include the electricity produced (between 267 MW and 300 MW), the CO_2 (2.6 million tons), the degassed liquid sulphur (up to 100 short tons per day (stpd) and the gasification solids (938 stpd dry basis). Additionally, bi-products from these processes would be diverted to the fertilizer manufacturing facility for the production of fertilizer products, these are discussed in that section.

COOLING TOWERS

The power block cooling tower

The power block cooling tower would be used to facilitate removal of the waste heat from the steam power cycle portion of the combined cycle CTG/HRSG. Approximately 95,500 gallons per minute (gpm) of water would be circulated in the power block cooling tower.

The process block cooling tower

The process block cooling tower would be used for heat rejection from the CO_2 compressor and an acid gas removal (AGR) refrigeration unit. The process block cooling tower circulation rate would be approximately 163,000 gpm of water.

The air separation unit (ASU) cooling tower

The ASU cooling tower would reject waste heat from the ASU. The ASU cooling tower circulation rate would be approximately 45,000 gpm of water and would be equipped with a high efficiency drift eliminator. The ASU, including the ASU cooling tower, would be designed, built, owned, and operated by third party. However, for purposes of the analysis staff considers this unit as part of the HECA facility.

Zero Liquid Discharge System

HECA would rely on a zero liquid discharge system (ZLD) to minimize the discharge of waste water. Plant wastewater, cooling tower blowdown, water treatment reject, evaporative cooler blowdown, and water from plant drains would be evaporated and concentrated using a conventional mechanical vapor recompression brine concentrator followed by a brine crystallizer. Resulting filter cake would be dispose of appropriately. Additional discussion of waste will be found in the **Waste Management** section of this document.

MANUFACTURING PLANT

The proposed manufacturing complex includes an ammonia synthesis unit. The ammonia synthesis unit manufactures ammonia (NH_3) for urea pastilles and urea-ammonium nitrate (UAN) solution production. The ammonia synthesis unit uses nitrogen from the ASU and high purity hydrogen from the Pressure Swing Adsorption unit (PSA) to convert the nitrogen and hydrogen to ammonia. This exothermic conversion occurs over an iron-based catalyst. The effluent is used to generate steam in the waste heat boiler. Cold liquid ammonia is stored in two vertical steel tanks housed in a second vessel and equipped with a vapor recovery system to prevent losses. A leak detection and repair (LDAR) program has been proposed by the applicant to limit fugitive emission from the NH_3 streams.

The proposed urea unit would be used to produce a concentrated urea solution by combining a purified stream of CO_2 recovered in the Acid Gas Removal system with ammonia from the ammonia synthesis resulting in a concentrated urea solution. This solution would be used as feed to produce UAN solution and urea pastilles, commercial agricultural fertilizers. **(**See **Project Description Figure 3)**

LINEAR FACILITIES

Construction of proposed linear facilities would include installation of approximately 32 miles total of underground pipelines, as well as construction of a 2-mile long transmission line and a proposed 5-mile industrial railroad spur that would be built and owned by the applicant (see **Project Description Figure 4, 5, 6, 7, 9** and **10)**.

Construction of the underground pipelines would consist primarily of crews performing the following typical pipeline construction activities: hauling and stringing of the pipe along the route; welding; radiographic inspection; coating of the pipe welds; trenching; lowering of the pipe into the trench; backfill of the trench; hydrostatic testing of the pipeline; purging the pipeline; and cleanup and restoration of construction areas. Grade cuts would be restored to their original contours and affected areas would be restored to their original state to minimize erosion (HECA 2012bb, §A116).

At areas where pipes would cross certain watercourses and roadways, the applicant proposes to use horizontal directional drilling (HDD) to avoid direct disturbances at these locations. HDD involves drilling from the ground surface adjacent to the area of concern, such as a stream, using a technique that guides the direction of the drill to pass under the stream and emerge on the ground surface on the opposite side without disturbing the streambed. Staging areas are required at the entry and exit points of the drill, with each “entry pit” requiring a temporary disturbance area of approximately 120 feet by 100 feet and each “exit pit” requiring an area of approximately 75 feet by 100 feet (HECA 2012bb, §A116).

Construction and installation of the approximately 2.8-mile electrical transmission line would follow a sequence similar to that of underground facilities, with trench excavation being replaced by the augering of holes to facilitate placement of the reinforced concrete foundations for the tubular-steel transmission structures, followed by backfilling and compaction. Grade cuts would be restored to their original contours, and affected areas would be restored to their original state to minimize the potential for erosion. To the extent possible, the material excavated from trenches and auger holes would be used to backfill around the foundations and in the trenches. Additional excess material that cannot be reused along the easement corridor would be transported to another reuse area or disposed of at an offsite landfill facility (HECA 2012bb, §A116).

The means for delivery of coal (200 rail cars per day would require staff to evaluate the applicant's proposal for two Transportation Alternatives: Alternative 1, rail transportation would entail construction of an approximately 5-mile new industrial railroad spur that would connect the project site to the existing San Joaquin Valley Railroad (SJVRR), Buttonwillow railroad line located north of the project site. This railroad spur would also be used to transport HECA manufactured fertilizer products, gasified solids, limestone fluxant and coal from the coal transloading facility located in Wasco, northeast of the project site. The truck route distance is approximately 27 miles. (HECA 2012bb, §A116). Staff and the applicant have initiated discussions with the California Public Utilities Commission (CPUC) staff regarding the appropriate measures for the permitting of two roads that would require lights, signals and other required safety measures, as well as the disruption of several agricultural crossings which would require either developing an alternative routing or a private crossing of the rail line. Staff, the applicant and CPUC continue working on the appropriate means of permitting this spur. Alternative 2 requires use of trucks for these transport needs.

Water Supply

The project would use approximately 6.6 million gallons per day (mgd) of water on a calendar year average basis, or approximately 7,427 acre-feet per year for process water needs. Water usage in the project can be divided into six categories: power block cooling tower, process cooling tower, air separation unit cooling tower, manufacturing complex, gasification solids, and heat recovery steam generator stack. This process water would be supplied from the Buena Vista Water Storage District (BVWSD). Potable water would be supplied by Westland Kern Water District (WKWD) located east of the project site, along Morris Road north of Station Road. (**Project Description Figure 4**). A complete analysis of the proposed water supply is located in the **Water Supply** section of this document.

Electrical Transmission System

An approximately 2.8-mile (0.8 miles are on the HECA site) electrical transmission line using approximately 15 steel poles outside of the project site, would interconnect the HECA switch yard to the future PG&E switching station and then to the first point of interconnection with the 230 kilovolt PG&E grid. The electrical transmission line extends east from the proposed switch yard within the northwest portion of the project site, across Tupman Road, then Morris Road and then eastward to the proposed new PG&E switching station. The majority of the approximately 2-mile route is adjacent to road shoulders and within areas of active agriculture. (**Project Description Figure 4** and **5**).

At this time, HECA does not have a power purchase agreement (PPA), but is in negotiations with PG&E.

Carbon Dioxide Pipeline to Elk Hills Oil Field CO_2 Processing Facility

CO_2 resulting from the above processes would be compressed at HECA and transported by an approximately 3-mile pipeline south to the EHOF CO_2 Processing Facility. The CO_2 pipeline would pass under the Kern River Flood Control Channel, the Buena Vista Water Storage District West Side Canal and the California Aqueduct. (**Project Description Figures 4, 6** and **10**).

Natural Gas Supply System

HECA would complete an approximately 13-mle natural gas interconnection with an existing PG&E pipeline north of the project. The interconnection will consist of one tap as well as a 100-foot by 100-foot metering station. This facility will be surrounded by a chain link fence. Also associated with this natural gas pipeline will be an additional metering station at the receiving end, located on the southwest side of the HECA project site (see **Project Description Figure 8**).

Industrial Rail Spur and Truck Route for Coal Transportation

Two alternative coal transportation routes would be evaluated: Alternative 1 would be a 5-mile private rail spur; Alternative 2 would be the truck route from the Wasco coal facility to HECA.

An approximately five-mile private rail spur, to be owned and maintained by HECA, is proposed to connect with the San Joaquin Valley Railroad in Buttonwillow. This rail spur, if constructed, would greatly reduce truck trips from the coal facility in Wasco to the project, approximately 27-miles one way using existing roads. This rail spur could also transport the fertilizer products from the proposed manufacturing facility to markets. The HECA site would also have a rail loop that would be capable of on-site holding of trains up to 1-mile in length prior to either unloading feed stock or on loading of manufacturing plant products (see **HECA Site Plan, Figure 6 and 9**).

Water Supply Pipelines

The raw water supply pipeline would be approximately 15-miles in length, connecting to to five new BVWSD groundwater wells. Potable water would be supplied by the West Kern Water District, through an approximately one-mile pipeline to the east of HECA **(see Project Description figures 4 and 9).**

SUPPORT INFRASTRUCTURE

Emergency Engines

The facility would have several emergency engines, all would be fueled using ultra-low sulfur diesel fuel. These would include two emergency standby diesel generators, each 2,000-kilowatt unit would be in an outdoor enclosure and connected by a stepdown transformer to supply emergency power to critical infrastructure including lube oil pumps, cooling pumps, gasification and auxiliary steam systems in the event of power loss from the project's generation equipment. Key infrastructure support would include the station battery chargers, uninterruptable power supply, heat tracing, control room, and other critical plant loads. An approximately 600-horsepower standby diesel-driven firewater pump would be located next to the firewater tank (HECA, 2012a).

Fire Protection

A detailed fire protection program is described in the AFC (HECA, 2012a, pps 2-41).The proposed program is evaluated in the **Worker Safety and Fire Protection** section of this PSA/DEIS. The proposed program includes design elements including conservative spacing between project elements. Discreet fire areas are used to identify potential hazards, protect personnel, and to control fire incidents within a confined area. Hard systems including a firewater storage tank, and distribution system, a dedicated fire loop with hydrants, and automatic fire-suppression systems would be in place. The system would include inert gas suppression systems, sprinker and water spray systems depending on the type of risk associated with the fire area. In addition a variety of alarms and personnel training would be utilized to insure fire safety. All elements would be consistent with National Fire Protection Association recommendations. Please refer to the **Worker Safety and Fire Protection** section of this PSA/DEIS for more specifics related to fire response and emergency services proposed for HECA construction and operations.

Hazardous Materials

There would be a variety of hazardous materials used and stored during construction and operation of HECA.

Hazardous materials that will be used during construction include gasoline, diesel fuel, oil, lubricants, and small quantities of solvents and paints, compressed gas cylinders including oxygen, acetylene and argon. All hazardous materials used during construction and operation would be stored on site in storage tanks, vessels and containers that are specifically designed for the characteristics of the materials to be stored; as appropriate, the storage facilities would include the needed secondary containment in case of tank/vessel failure. As part of a risk management plan (RMP), Material safety data sheets (MSDS) for each chemical in use would be required to be on site during construction and operations, and all contractors and staff would be instructed in their use in avoiding associated materials accidents and responding appropriately should an accident or material related incident occur. Maintenance of up to date MSDS books and locations would be the responsibility of each contractor on the site.

Hazardous materials routinely used and stored on site during operation would include methanol, petroleum products, flammable and compressed gases, acids and caustics, ammonia, water treatment and cleaning chemicals. Storage of all hazardous materials would be in appropriately designed storage areas. All bulk tanks would be provided with secondary containment in case of spills or leaks.

The **Hazardous Materials Management** section of this PSA/DEIS provides additional data on the hazardous materials that would be used during construction and operation, including quantities, associated hazards and permissible exposure limits, storage methods, and special handling precautions.

Waste Management

While waste management is primarily the process whereby all wastes produced at the project site are properly collected, treated (if necessary), and disposed of; the technical area is also responsible for evaluating past activities on a proposed site, and the potential impacts associated with additional proposed actions at that site. For the HECA proposed property a series of Environmental Site Assessments (ESAs) were completed for the proposed project site. The last Phase I ESA was dated April 2012, prepared by URS for the 453 acre project proposed HECA site. The results of the preliminary soil sampling and analytical testing indicate that there are elevated concentrations of petroleum hydrocarbons and other contaminants affected by previous site activities on a former wash area immediately north of the HECA site. There is soil staining in various areas on the project site that is likely caused by handling of fuel, lubricating oils, and pesticides. Residual contaminants at the site include organochlorine pesticides, dieldrin, endrin, and endosulfan (HECA 2012e, page 5.13-3). Soil samples taken at the site indicate that concentrations of the pesticides dieldrin, endrin, and endosulfan exceed the Regional Water Quality Control Board (RWQCB) Environmental Screening Levels, but did not exceed the California Human Health Screening Levels (CHHSLs) (HECA 2012e, page 5.13-3)). The Department of Toxic Substances Control (DTSC) has indicated that additional site characterization is required to further define the level of contamination at the proposed site. Energy Commission staff is currently working with the applicant and DTSC to develop the necessary characterization information and a plan for addressing the potential issues associated with the past contamination.

Waste management for the proposed project would also insure that all wastes produced at the project site are properly collected, treated (if necessary), and disposed of. Wastes include process and sanitary wastewater, nonhazardous waste, and hazardous waste, both liquid and solid. These include the gasification solids comprised of vitrified (glass-like) material produced by melting the mineral matter in the feedstock with small amounts of unconverted carbon. These gasification solids would be stored for off-site transportation by rail or truck. The applicant is exploring potential markets for this material which would reduce the impact of landfilling, the associated transport and disposal costs. Among the potential uses being explored are uses in cement production, as sand blasting grit and possibly as roofing granules. The **Soils and Surface Water** section of this PSA/DEIS discusses process wastewater and sanitary wastewater. For all other wastes, the **Waste Management** section of this PSA/DEIS would detail the process by which both hazardous and nonhazardous wastes from HECA construction and operation would be appropriately stored, transferred and disposed.

HECA AND THE ELK HILLS ENHANCED OIL RECOVERY AND CO_2 SEQUESTRATION PROJECT

As noted above, HECA is dependent upon the sale of CO_2 to Occidental of Elk Hills (OEHI), who plans to utilize CO_2 resulting from HECA operations to increase the effectiveness of its enhanced oil recovery program (EOR) by adding an injected CO_2 component to its existing waterflood method of sweeping the oil shale to increase oil production. HECA CO_2 production and delivery to OEHI, utilized in a water alternating gas (WAG) process, would potentially result in the permanent geologic sequestration of substantial quantities of CO_2, and important greenhouse gas. (see the **Sequestration**

and Greenhouse Gas section): Some key features of the proposed EOR program that would utilize the CO_2 from HECA are noted below.

The proposed HECA sequestration and enhanced oil recovery project would:

- Utilize CO_2 from HECA for enhanced oil recovery and carbon sequestration purposes;
- Utilize a water-alternating gas (WAG) technique for oil recovery;
- Develop a CO_2 EOR processing facility connecting with 13 satellite injection facilities that would be expected to occupy approximately 135.6 acres;
- Utilize an estimated total length of phased new pipeline of 652 miles, located in existing pipeline corridors and sited on disturbed acreage. At-grade pipelines would be up to 26 inches in diameter;
- The EOR may include approximately 720 producing and injection wells;
- Require well installation footprints of 130' x 280' (36,400 square feet or 0.84 ac.);
- The EOR proposes to use 107 million standard cubic feet/day (mmscfd) of CO_2 delivered from HECA (up to approximately 2.6 million tons per year from HECA);
- This process would require OEHI to seek approval from DOGGR for the miscible gas injection project to use methane/ethane recovered gases from oil production combined with the CO_2 mixture;
- The project would employ injection wells drilled to approximately 5,000 feet below ground surface, sealed by the "Reef Ridge Shale" and within the "Monterey Formation" 4,500 to 10,000 feet below surface.
- The project proposes at least 20 years of CO_2 capture/delivery from HECA. This is equivalent to less than 5 percent of the useable reservoir pore volume above the free water level.
- The project would employ a closed loop fluid and gas recycle/reuse/reinjection process.

Energy Commission staff evaluates the EOR program in this PSA/DEIS as a part of the whole project (CEQA reference). It is an integral part of the HECA planned project, and the means by which geologic sequestration of a greenhouse gas (CO_2) is potentially accomplished. The actual permits associated with the EOR project will be issued by other agencies, including The Department of Conservation, Division of Oil, Gas and Geothermal Resources (DOGGR), Kern County, and the San Joaquin Valley Air Pollution Control District (SJVAPCD), each agency with specific regulatory authorities over the activities on the EHOF.

DOGGR would separately permit the wells, pipelines and associated structures, including the proposed CO_2 handling facility, with the OEHI EOR project. DOGGR has statutory responsibility under Division 3 of the Public Resources Code to regulate all oilfield operations in the state of California. DOGGR is authorized by law to approve the injection and extraction wells and associated well facilities, to regulate down-hole operations, and to be responsible for appropriate regulation of surface activities relating to the OEHI CO_2 EOR. The wells to be used for injection of the CO_2 would be permitted as Class II injection wells under the Underground Injection Control (UIC) program in the Federal Safe Drinking Water Act (SDWA), 42 United States Code § 300h-4. DOGGR has primacy to approve Class II injection wells in the state of California under Section 1425 of the SDWA, see U.S. Environmental Protection Agency (USEPA, 1983). The wells and associated well facilities for the OEHI CO_2 EOR will be permitted pursuant to authority provided to DOGGR in the Public Resources Code and the SDWA and in accordance with applicable DOGGR regulations.

PROJECT CONSTRUCTION AND CLOSURE

An Engineering, Procurement, and Construction (EPC) contractor would be responsible for the engineering, procurement, and construction of the project. The EPC contractor would select subcontractors for certain specialty work as required.

Mobilization: The EPC contractor would be expected to commence truck deliveries and ground disturbance as soon as possible should the project secure Energy Commission approval and a final Record of Decision (ROD) from the DOE. Project site preparation work would include site grading and storm water/erosion control. Gravel and road base material would be used for temporary roads, laydown, parking, and work areas. Construction planning would include the evaluation of existing county roads. The roads would be upgraded as necessary to handle the increased loads and traffic.

Project Site Construction: Construction activities for the project would occur throughout the 42-month construction period. All construction laydown and parking areas would be located within the project site and the controlled area. On-site construction activities include clearing and grubbing, grading, hauling, layout of equipment, delivery and handling of materials and supplies, and Project construction and testing operations.

Commencement of commissioning activities would occur beginning at 34 months, and commercial operation would be expected at approximately 51 months.

Site Access: Construction site access would be via Dairy Road for truck deliveries and Adohr Road for construction craft vehicles arriving and departing the site. Dairy Road currently ends at Adohr Road, but would be extended during project construction. This extension would be permanent and would also be used for personnel access during operations. The peak construction site workforce levels and operations workforce estimates can be reviewed in the **Socioeconomics** section of this **PSA/DEIS.**

PROJECT CONSTRUCTION

General Grading, Leveling and Construction Facility Installation

The project site occurs in an area of relatively flat topography. Site grading would occur as necessary to form level building pads for major process units. Initial site preparation operations would include construction of temporary access roads, craft parking, laydown areas, office and warehouse facilities, installation of erosion control measures, and other improvements necessary for construction.

Storm Drainage System

Existing drainage patterns outside the site boundary would remain undisturbed. No runoff from outside the site boundary would flow onto the project site. All surface runoff during and after construction would be controlled in accordance with the requirements of the Drainage, Erosion, and Sedimentation Control Plan, and all other applicable LORS.

Erosion and Sediment Control Measures

Protection of soil resources would be an important factor in the design of the erosion and sedimentation controls. Erosion control measures would include construction of storm water retention basins and related site drainage facilities to control runoff within the site boundary. Additional project site erosion control would be accomplished during construction through the use of strategically placed berms, swales, and culverts to redirect runoff toward the storm water retention basins. Sandbags, filter bales, silt fences, and/or temporary dams would be installed, as needed, to minimize the volume of sediment carried by storm runoff and to prevent the erosion of slopes and temporary drainage facilities. Grades would be designed to prevent the effects of ruts and ponding.

Following each significant precipitation event, a site review of the effectiveness of the erosion control plan would take place. Storm water would be retained on site for impoundment in the storm water retention basins (please see the **Soils and Surface Water** section of this **PSA/DEIS** for full analysis).

Restoration of Temporary Disturbance

As proposed, temporarily disturbed areas will be restored to their preconstruction conditions. Temporary access roads used during construction will also be re-graded and restored to pre-existing function and grade.

PROJECT CLOSURE

At some point in the future, the project will cease operation and close down. At that time, it will be necessary to ensure that the closure occurs in such a way that public health and safety and the environment are protected from adverse impacts. Although the setting for this project does not appear, at this time, to present any special or unusual closure problems, it is impossible to foresee what the situation will be in 30 years or more when the project ceases operation. Therefore, provisions must be made that provide the flexibility to deal with the specific situation and project setting that exist at the time of closure. Laws, Ordinances, Regulations and Standards (LORS) pertaining to facility closure are identified in the sections dealing with each technical area. Facility closure will be consistent with LORS in effect at the time of closure. Facility closure of the project can be either temporary or permanent. Facility closure would include plans for all structures on the 453 surface acres, underground objects, and associated linear facilities such as transmission lines, pipelines, and the railroad spur previously described.

The project closure process is described in detail in the **Compliance Conditions** section of this PSA/DEIS. This section describes at least three circumstances in which a facility closure can take place: planned closure, unplanned temporary closure and unplanned permanent closure. The section also details what would be required by the Energy Commission to protect public health and safety and the environment from adverse impacts in each of the above instances.

Recent Information Affecting the Project

As is often the case in a complex proceeding, ongoing project design produces features and information that could not be included in the Application for Certification, or was being developed in the ongoing process of project refinement. Recent information that staff has attempted to incorporate into this PSA/DEIS, but may require additional information from the applicant and a fuller discussion in the Final Staff Assessment/Final Environmental Impact Statement (FSA/FEIS), is noted below:

Proposed addition of limestone fluxant

- Limestone fluxant will be added to the coal and petroleum coke feedstock; on average 175 ton/day or 59,000 tons/year of fluxant would be used;
- The average gasification solids flow rate increases from 850 tons/day to 938 tons/day. The properties of the gasification solids will not change. The options for eventual disposition of the gasification solids will not change due to the addition of fluxant;
- Fluxant will be delivered by truck and would be either tarped or enclosed, to eliminate potential fugitive dust from the material as it travels to the site;
- The fluxant will be stored in a silo that will be approximately 30 feet in diameter and 80 feet tall, to be located to the north of the proposed feedstock barn;
- The fluxant unloading and silo area would have a baghouse to control dust.
- The flux would be added to the feedstock on the conveyor at the point where it exits the feedstock storage barn;
- In the gasifier the limestone splits into two components, calcium oxide and carbon dioxide. The calcium oxide becomes part of the gasification solids. The carbon dioxide becomes part of the syngas stream and is captured in the Rectisol Unit;
- The additional CO_2 would flow to the EHOF enhanced oil recovery stream from HECA, and the CO_2 emitted from the turbine/feedstock dryer and CO_2 vent would also increase proportionally.
- Carbon capture would be expected to remain at 90 percent or greater of the CO_2 in the syngas exiting the gasifier;
- Maximum daily trucks increase by 10 fluxant trucks and 2 gasification solids trucks under Alternative 1-with the rail spur;
- Maximum daily trucks increase by 10 fluxant trucks and 9 gasification solids trucks under Alternative 2-no rail spur.

Inclusion of electrical demand for the Air Separation Unit

The Air Separation Unit (ASU) is proposed by the applicant to be owned and operated by a separate company, and as such, the applicant did not originally provide detailed information about its electrical demand. Staff considers the ASU to be part of the proposed project, subject to the Energy Commission's jurisdiction, and therefore included in staff's evaluation of project impacts and LORS conformance. On April 10, 2013, the applicant provided staff with the unit's electrical demand. Technical staff have incorporated the new information and developed preliminary assumptions that are reflected in the **Powerplant Efficiency** and the **Sequestration and Greenhouse Gas** sections. Staff now assumes that the proposed ASU power use should be factored into the project's anticipated parasitic load. The following information is being evaluated by staff:

- ASU On-Peak Power Demand: 109 MW
- ASU Off-Peak Power Demand: 103 MW

Final Design Criteria for the Electrical Generation Equipment

Staff will need final design criteria and a clear statement regarding the equipment's heat rate and a complete listing of all parasitic loads to be attributed to the project. The applicant's statement of the gross and net electrical production from HECA continues to fluctuate based on continued design refinement by the applicant and the equipment manufacturer, Mitsubishi Heavy Industries. The information is reflected in a variable assessment of the gross and net electrical output for HECA. Gross output may vary as noted in information provided to the SJVAPCD and in the April 10, 2013 email to Energy Commission staff (URS, 2013):

- Gross electrical output 405 MW as noted in the AFC, and 431 MW in other documents;
- Net electrical output may vary from 300 MW as noted in the AFC, and 267 MW.

No information on the overall project heat rate and breakdown of auxiliary loads based on the 431MW figure has been provided to staff at this time. Staff evaluation of this preliminary information has a variable affect on the analysis contained in the **Powerplant Efficiency**, **Sequestration and Greenhouse Gas** and the **Air Quality** sections of this PSA/DEIS. A clear statement of the project information will be required prior to completion of the Final Staff Assessment/Final Environmental Statement. (See the sections noted above for additional analysis).

REFERENCES

HECA 2012e – SCS Energy California/Hydrogen Energy California, LLC /J. L. Coyle (tn 65049). Amended Application for Certification, Vols. I, II, and III (08-AFC-8A), dated 05/02/12. Submitted to CEC Docket Unit on 05/02/2012.

URS 2013. Shileikis, D. to R. Worl, CEC. (tn: 70376) Response Regarding MW and Limestone Fluxant. Dated 4/10/2013. Posted: April 17, 2013. (PDF File, 2 Pages, 82.9 kb)

PROJECT DESCRIPTION - FIGURE 1

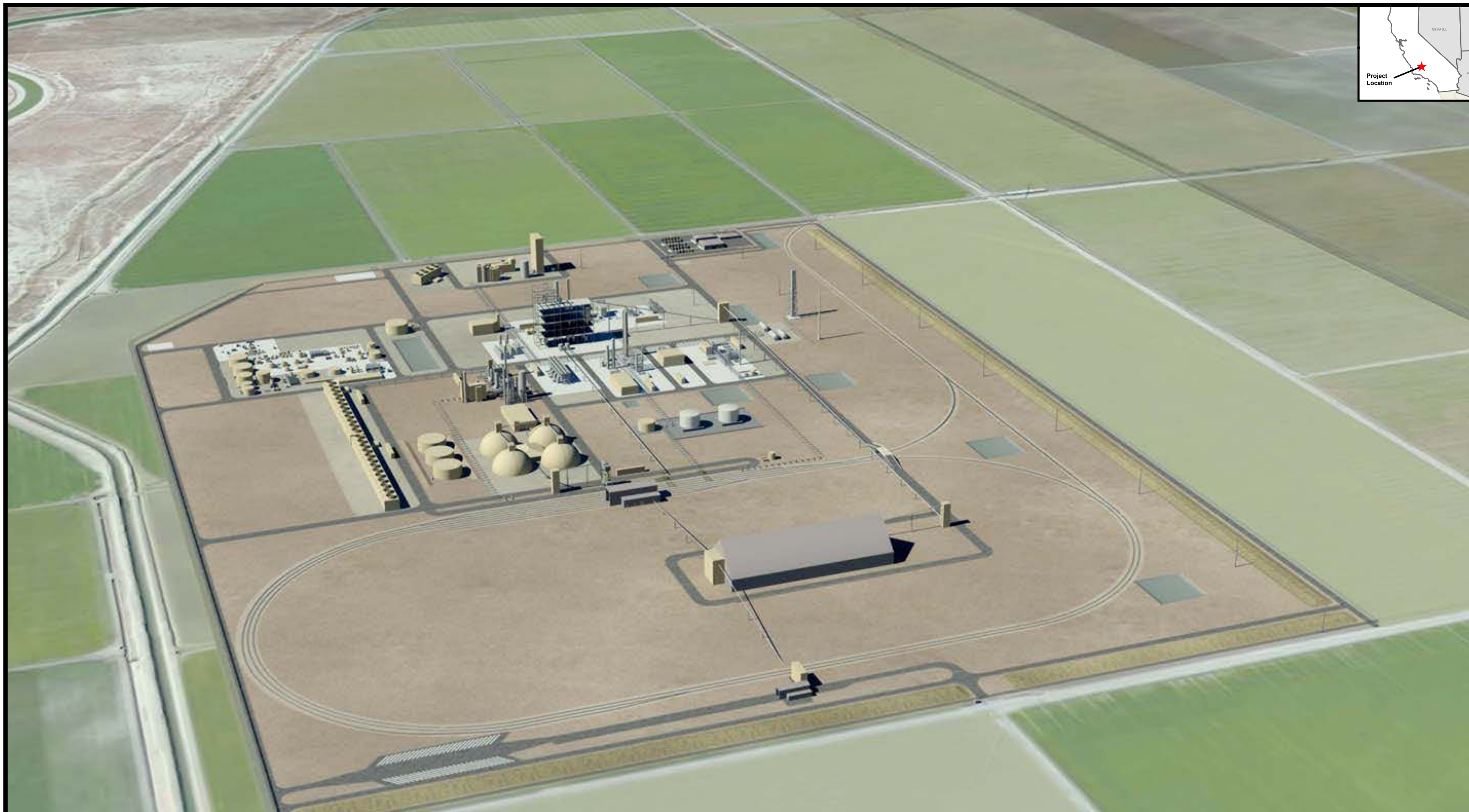
Hydrogen Energy California - Project Vicinity

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: 08 AFC-8A

PROJECT DESCRIPTION - FIGURE 2

Hydrogen Energy California - Project Site - Project Rendering

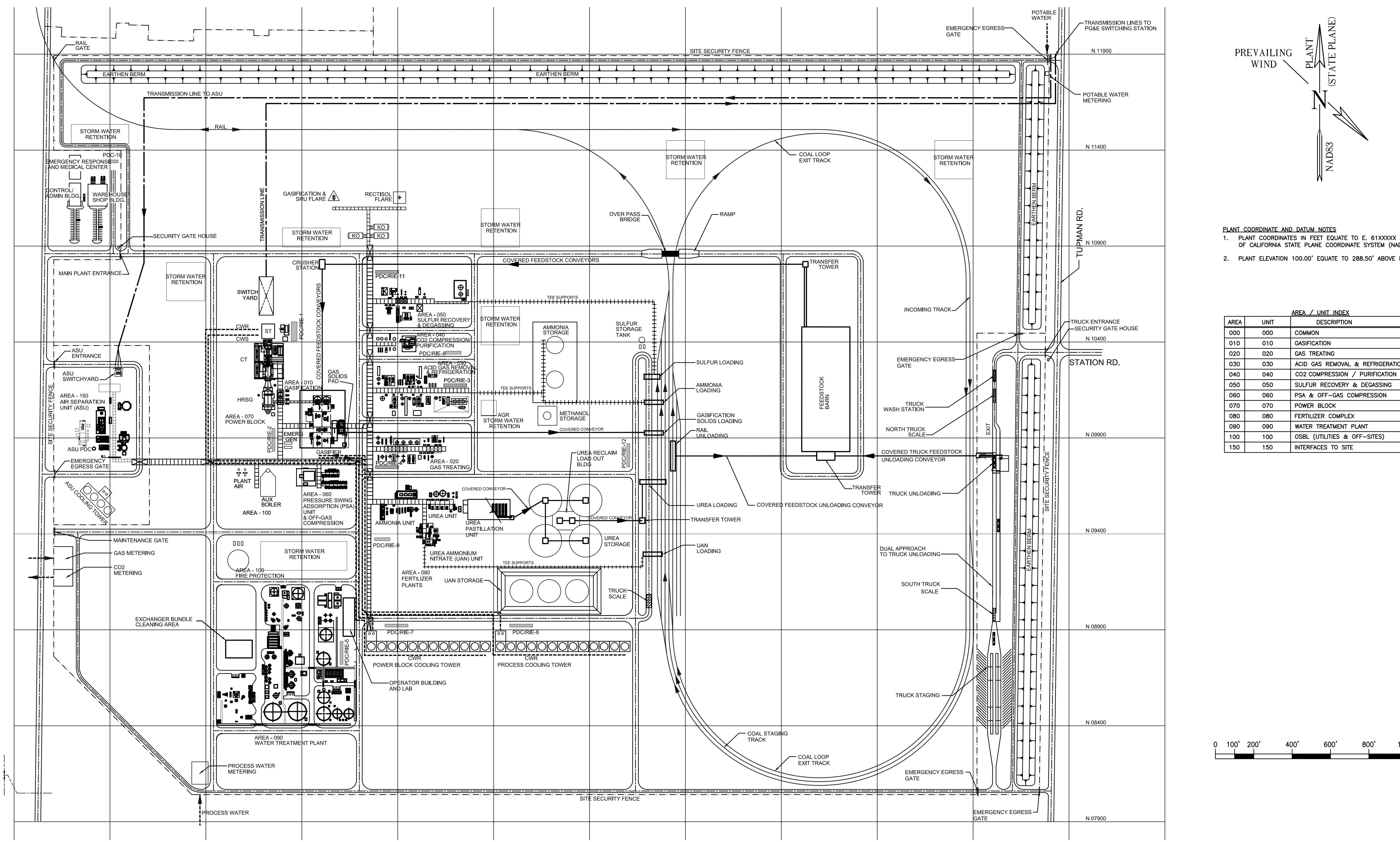


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: 08 AFC -8A

PROJECT DESCRIPTION - FIGURE 3

Hydrogen Energy California - Preliminary Temporary Construction Facilities



PLANT COORDINATE AND DATUM NOTES

1. PLANT COORDINATES IN FEET EQUATE TO E. 61XXXXX AND N. 23YYYYY OF CALIFORNIA STATE PLANE COORDINATE SYSTEM (NAD 83 ZONE V.)
2. PLANT ELEVATION 100.00' EQUATE TO 288.50' ABOVE MSL (NAVD88.)

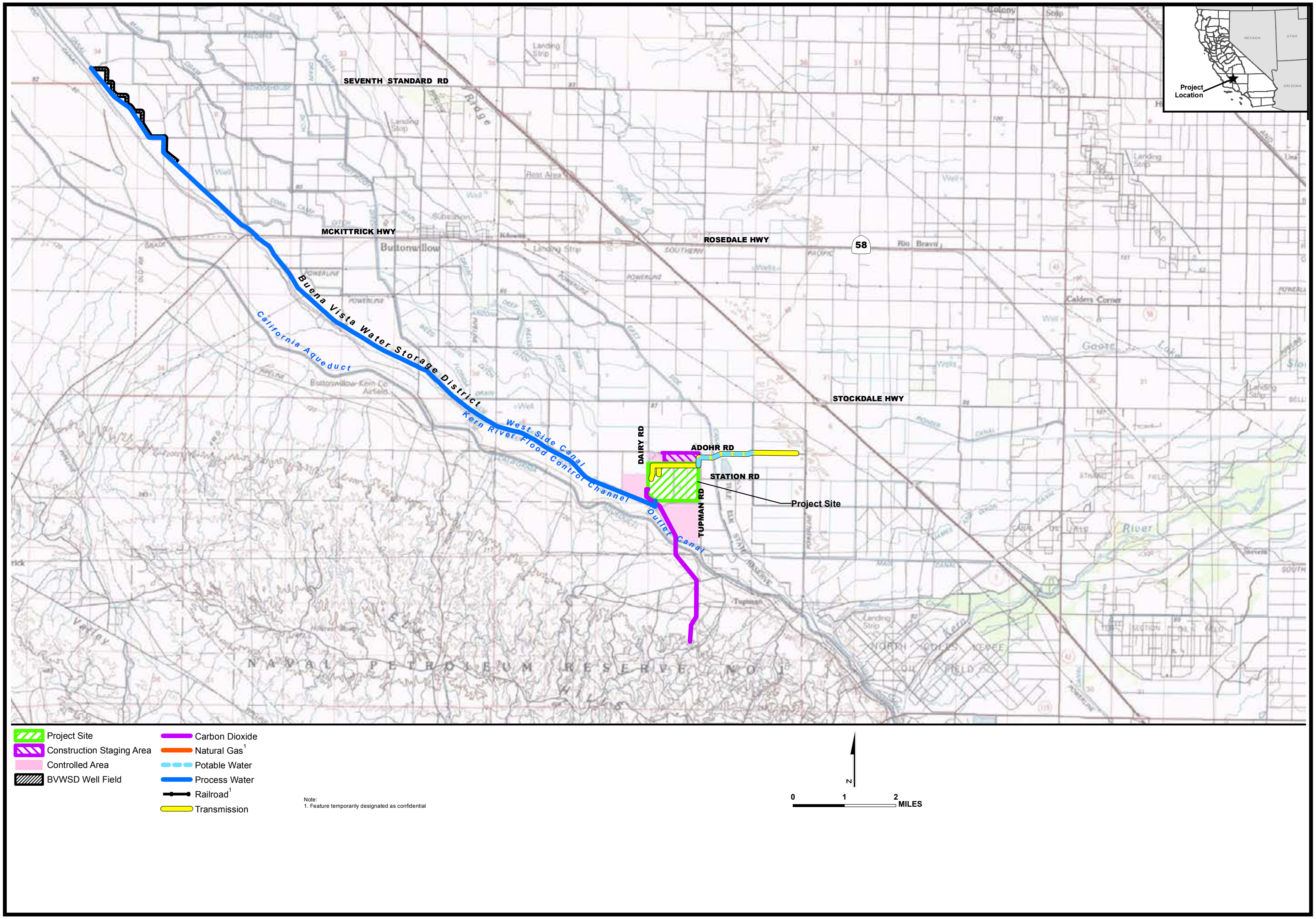
AREA / UNIT INDEX

AREA	UNIT	DESCRIPTION
000	000	COMMON
010	010	GASIFICATION
020	020	GAS TREATING
030	030	ACID GAS REMOVAL & REFRIGERATION
040	040	CO2 COMPRESSION / PURIFICATION
050	050	SULFUR RECOVERY & DEGASSING
060	060	PSA & OFF-GAS COMPRESSION
070	070	POWER BLOCK
080	080	FERTILIZER COMPLEX
090	090	WATER TREATMENT PLANT
100	100	OSBL (UTILITIES & OFF-SITES)
150	150	INTERFACES TO SITE

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: 08 AFC -8A

PROJECT DESCRIPTION - FIGURE 4
Hydrogen Energy California - Site and Linear Facilities

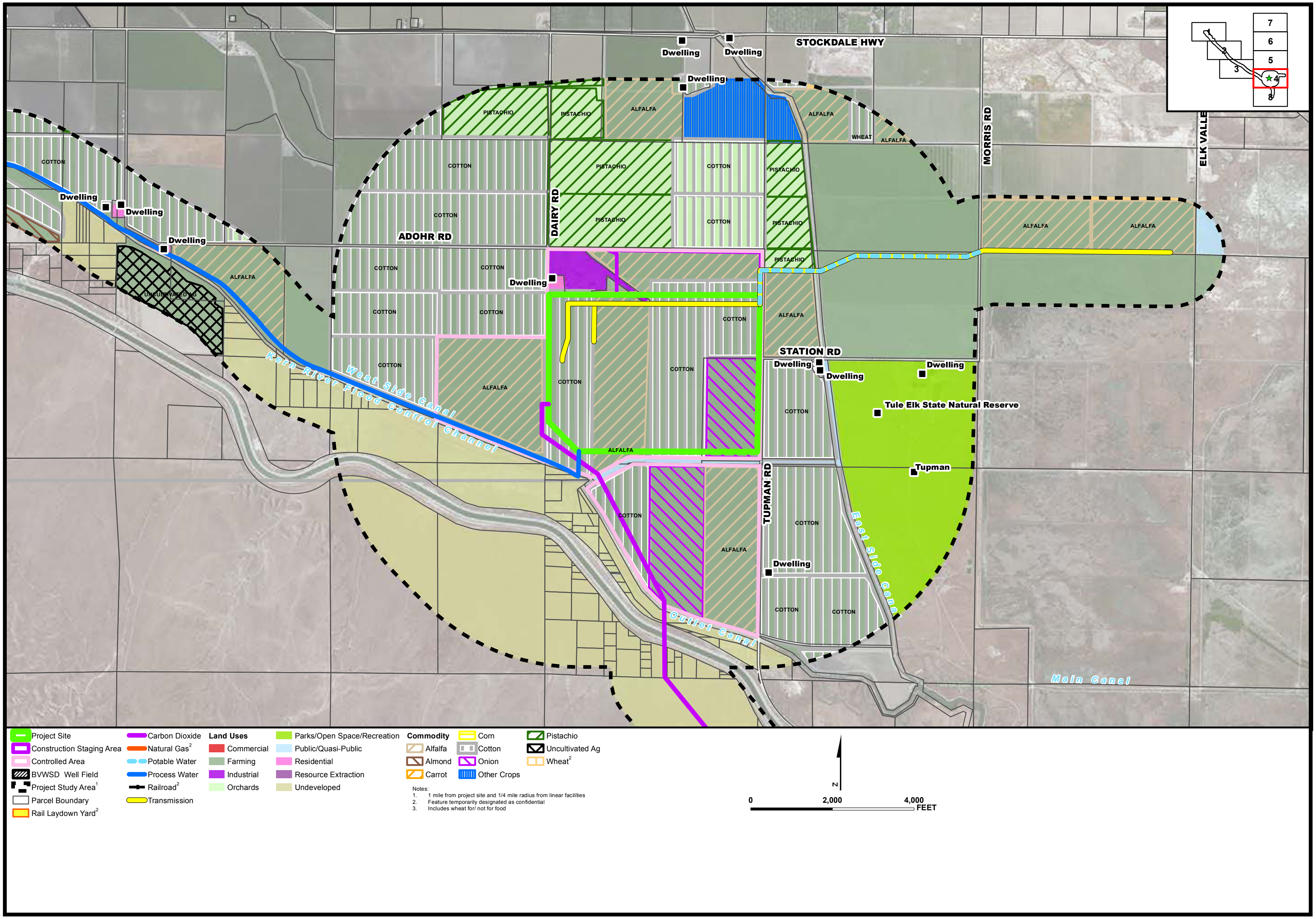


PROJECT DESCRIPTION

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: 08 AFC -8A

PROJECT DESCRIPTION - FIGURE 5

Hydrogen Energy California - Overview - Existing Land Uses

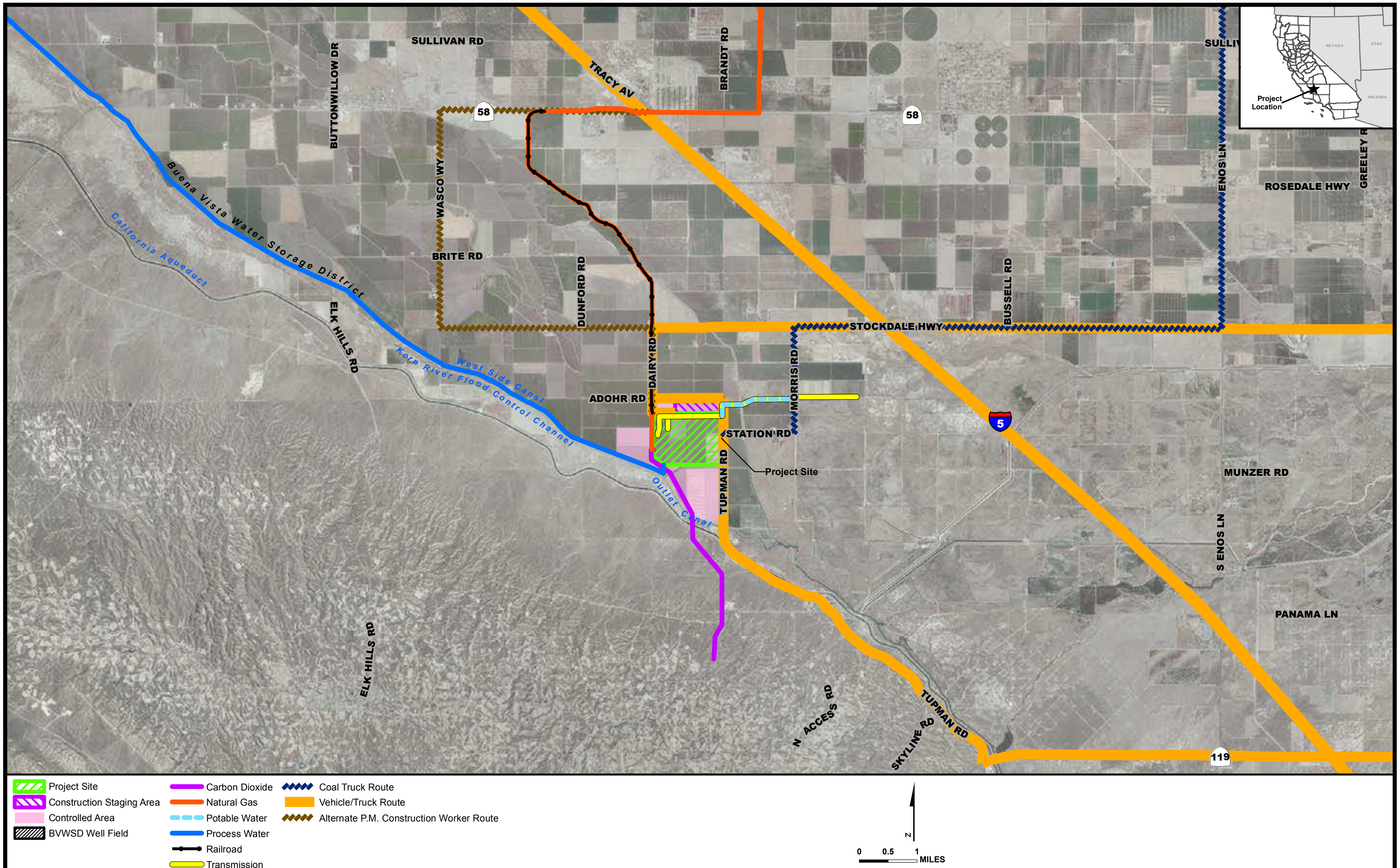


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: 08 AFC -8A

PROJECT DESCRIPTION - FIGURE 6

Hydrogen Energy California - Rail Delivery and Traffic Routes

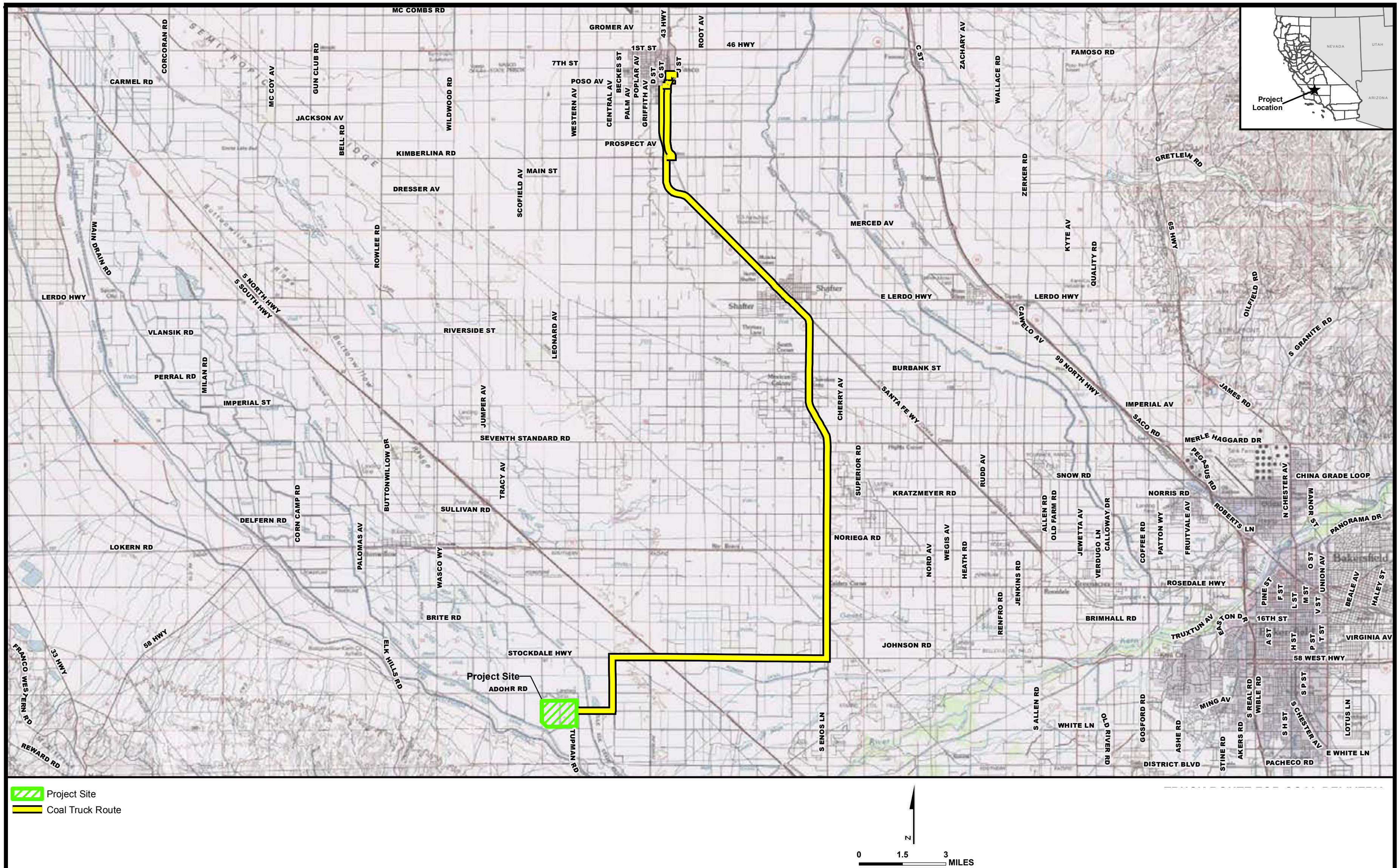


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

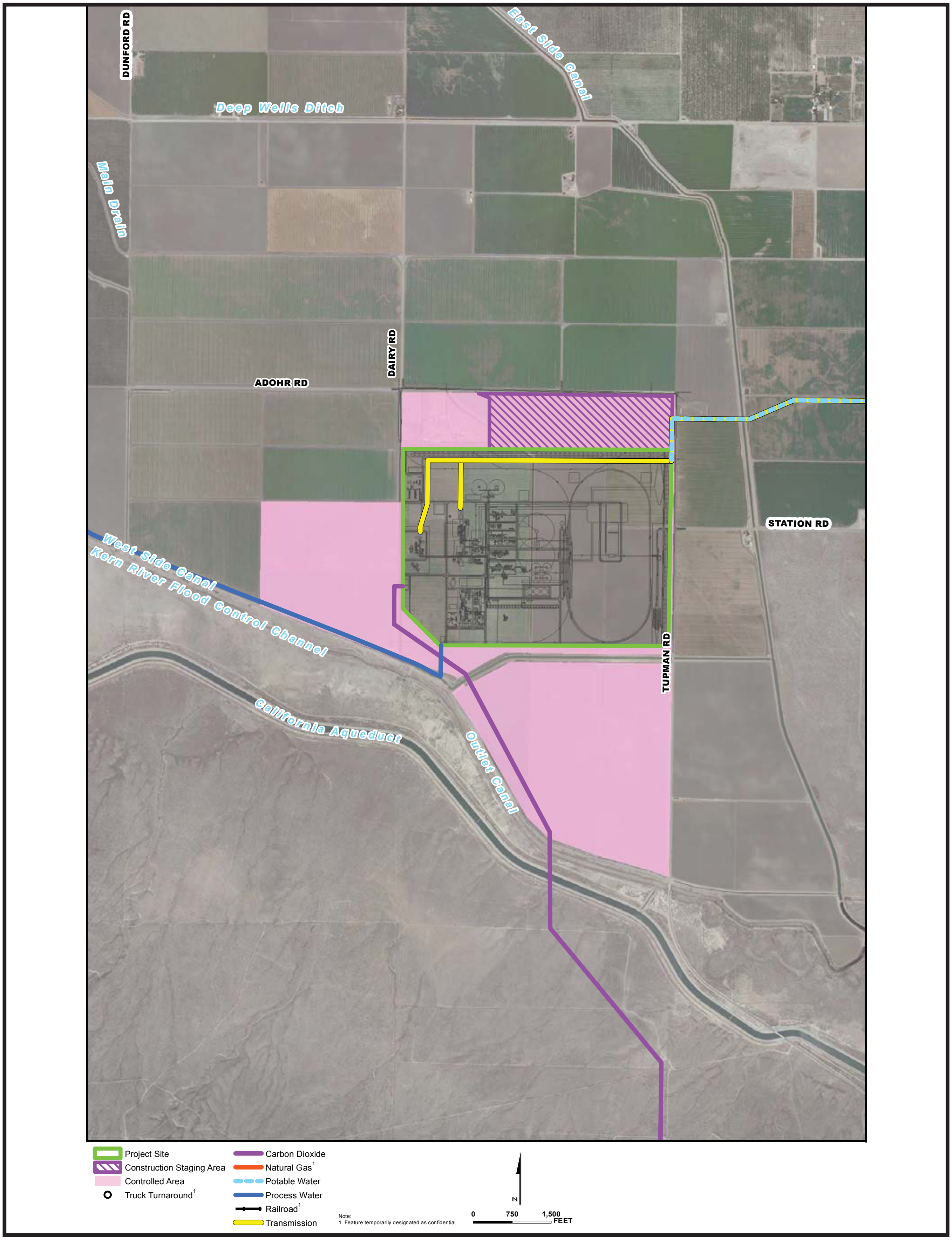
SOURCE: TN66876

PROJECT DESCRIPTION - FIGURE 7

Hydrogen Energy California - Truck Route for Coal Delivery - (Transportation Alternative 2)

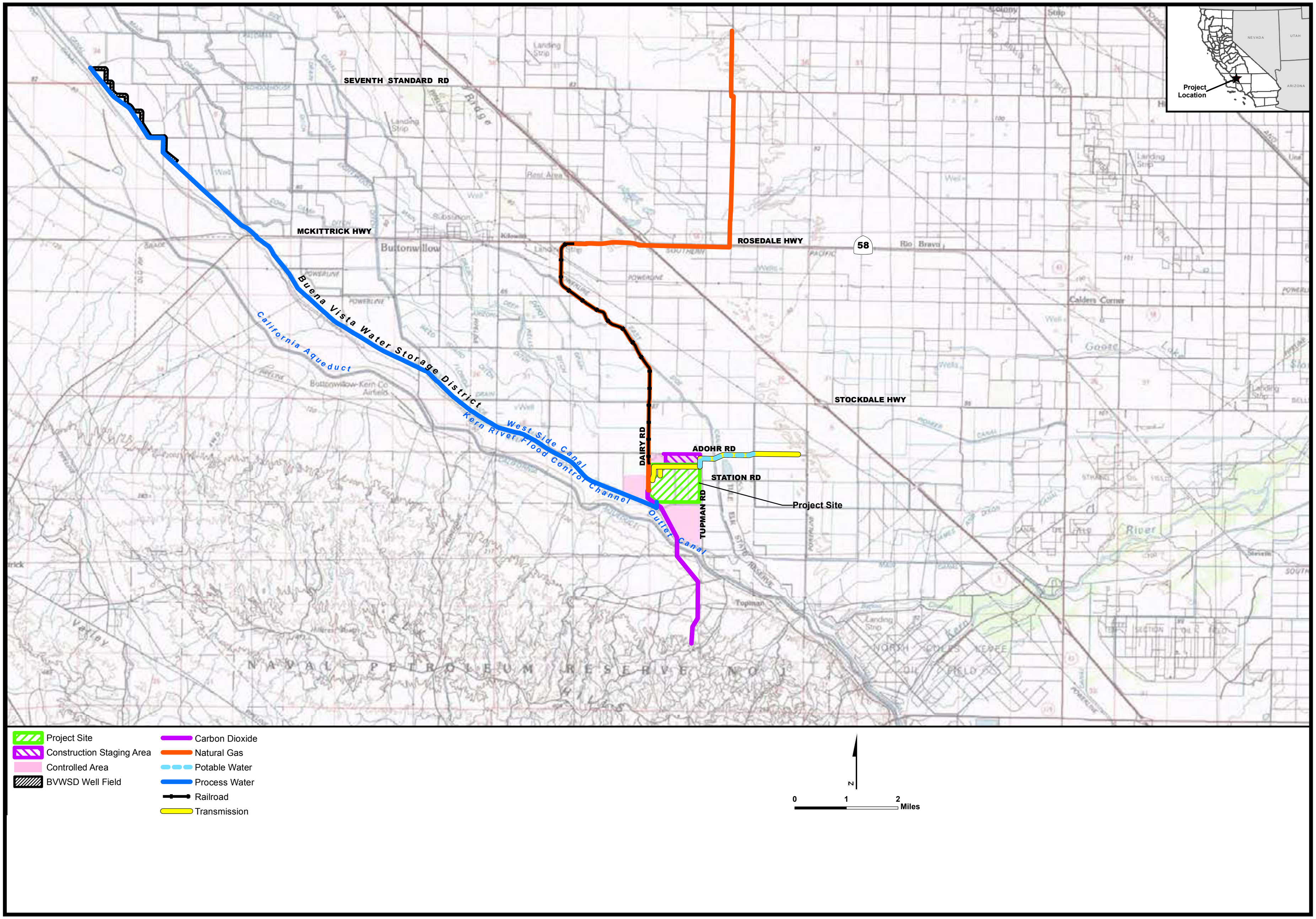


PROJECT DESCRIPTION - FIGURE 8
Hydrogen Energy California - Site Plan with Control Area Configuration



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: 08 AFC-8A

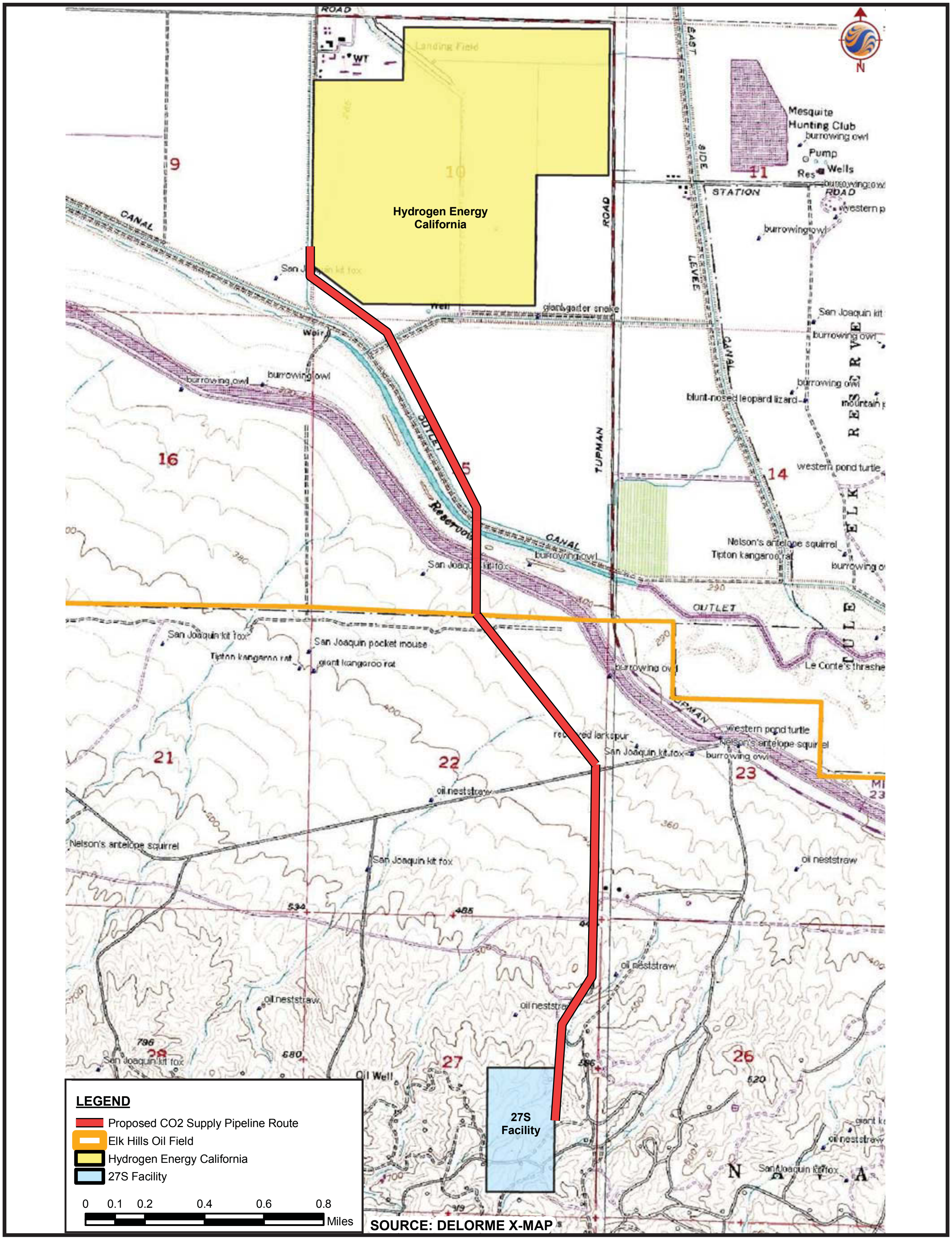
PROJECT DESCRIPTION - FIGURE 9
Hydrogen Energy California - Revised Rail Route and Linears - (Transportation Alternative 1)



SOURCE: TN 67969

PROJECT DESCRIPTION - FIGURE 10

Hydrogen Energy California - HECA CO_2 Pipeline and EOR CO_2 Facility



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: HECA AFC Vol 1, Appendix A - Figure 3

ENVIRONMENTAL ASSESSMENT

AIR QUALITY

Prepared by William Walters, P.E.
and Nancy Fletcher

SUMMARY OF CONCLUSIONS

The Hydrogen Energy California Project (HECA)[1] should comply with all applicable air quality laws, ordinances, regulations, and standards (LORS) and should not result in significant air quality impacts provided the recommended conditions of certification are adopted by the Commission and implemented by the project owner. The project has secured emission reduction credits in sufficient quantity to meet San Joaquin Valley Air Pollution Control District (SJVAPCD or District) requirements. The applicant has also agreed to provide funding to the District's Emission Reduction Incentive Program (ERIP) to create additional emission reductions necessary for General Conformity and California Environmental Quality Act (CEQA) compliance purposes as determined necessary by the District. Additionally, these emission reduction credits would fully offset all onsite project emissions of nonattainment pollutants and their precursors that occur within the San Joaquin Valley Air Basin (SJVAB) at a minimum offset ratio of 1:1. The Occidental Petroleum Carbon Dioxide Enhanced Oil Recovery component would also comply with all applicable air quality LORS.

Staff has assessed the potential for localized impacts and regional impacts for both the project's construction and operation. As a product of this analysis staff has recommended mitigation and monitoring requirements sufficient to reduce the potential adverse construction and operating emission impacts to less than significant.

Staff has reviewed the District's Preliminary Determination of Compliance (PDOC) and finds that it is generally complete and accurate, but notes that there are a number of consistency and continuity issues in the District conditions. Staff has provided a comment letter on the PDOC addressing these issues and staff expects that the District will implement revisions to the PDOC and the PDOC conditions to address these issues in the Final Determination of Compliance (FDOC) that will be presented in the Final Staff Assessment/Final Environmental Impact Statement (FSA/FEIS).

The District developed a sulfur oxides (SOx) for particulate matter (both particulate matter less than 10 microns [PM10] and particulate matter less than 2.5 microns [PM2.5]) interpollutant trading ratio of one-to-one and concluded that this would be adequate to manage regional particulate matter impacts and progress towards attainment. However, staff notes that the one-to-one interpollutant trading ratio is lower than what has been historically required by the District on similar past power plant cases. In addition, the District's recently adopted air quality management plan for fine particulate identifies a 4.1:1 SOx for PM2.5 interpollutant trading ratio. Therefore, in a formal comment letter regarding the PDOC dated March 28, 2013, staff has asked the District to provide additional information on why a 1:1 SOx for PM10 and PM2.5 interpollutant trading ratio for this project would be allowed, and whether that value would truly provide a net air quality benefit. Staff's final determination on whether the

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[1] A comprehensive acronym list is provided at the end of this section.

proposed mitigation meets CEQA requirements, or whether additional mitigation may be required, will in part be based on the answers to these questions received from the District, as well as, additional review and consideration of the other mitigation measures proposed for the project; including the applicant's funding of the District's ERIP.

Staff has also considered the potential for adverse air quality impacts to the minority population surrounding the site. With the adoption of the recommended conditions of certification, the project's direct and cumulative air quality impacts would be reduced to less than significant. Therefore, the project will not result in a significant or adverse impact to an identified environmental justice population.

The applicant has made recent revisions to the project, including removing ammonia as an export product and adding a limestone fluxant to the gasifier feedstock that would impact transportation emissions and stationary source emissions and District permitting requirements. Staff is also aware of very recent but apparently very minor revisions to the gas turbine fuel consumption estimates. Staff will obtain revisions to the project emissions estimates, as well as the related project description information updates, and will provide the revised information in the FSA/FEIS. Staff's air quality conclusions for the project based on the evaluation of the information provided in the Amended AFC and the subsequent formal data responses provided by the applicant and do not include evaluation of these most recent project revisions.

INTRODUCTION

On May, 5, 2012, Hydrogen Energy California, LLC (applicant) submitted an amended Application for Certification (AFC) to construct and operate an integrated gasification combined cycle (IGCC) power generating facility near the community of Tupman in Kern County, California. The applicant originally submitted an AFC on July 31, 2008 and a revised AFC on May 28, 2009 for a change in the project site. The project was acquired by SCS Energy LLC in 2011. The project was redesigned and key components were modified including the addition of an integrated fertilizer manufacturing complex. The Amended AFC filed on May 2, 2012 includes the power generating facility, the fertilizer manufacturing complex, and the capture, transport and use of carbon dioxide (CO_2) for enhanced oil recovery (EOR).

The proposed project is designed to operate on a fuel blend of western sub-bituminous coal and petroleum coke. The proposed feedstock blend is 75 percent coal, sourced from mines located outside the State of California, and 25 percent petroleum coke (pet coke), a product from California refineries. The majority of California's petcoke production is currently shipped overseas. However, a small portion is used in existing California power plants. The feedstock fuel would be gasified to produce a synthetic gas (syngas) which would be further processed to generate a hydrogen-rich fuel. The hydrogen-rich fuel would be the primary fuel for the combined cycle gas turbine and fertilizer manufacturing complex. In addition, CO2 from this process would be captured and used for EOR at an oil production field, Elk Hills Oil Field (EHOF), located approximately four miles south of the proposed HECA site. EHOF is owned and operated by Occidental of Elk Hills, Inc. (OEHI).

The U.S. Department of Energy has selected HECA for financial assistance under the Clean Coal Power Initiative Round 3 (CCPI) program. The project is therefore subject to the National Environmental Policy Act (NEPA). The NEPA and CEQA review for this project will be combined in this analysis. As discussed in the Introduction Section of this Preliminary Staff Analysis, this document analyzes the project's impacts pursuant to both NEPA and CEQA. The two statutes are similar in their requirements concerning analysis of a project's impacts. Therefore, unless otherwise noted, staff's use of, and reference to, CEQA criteria and guidelines also encompasses and satisfies NEPA requirements for this environmental document.

The project proposes to generate between 405 and 431 MW gross or an average of 416MW gross electrical power and between 151 to 266 MW net after accounting for onsite auxiliary power loads. The lower values apply during the periods of maximum fertilizer production and the higher values apply during periods of maximum electricity production. When considering the air separation unit and the electricity used by OEHI during enhanced oil recovery operations, which are both part of the project as described by the applicant, the net electricity generation available to California consumers drops to 52.5 MW of new electrical capacity added to the grid during periods of maximum electricity production. The project would be a net consumer of 61.8 MW from the grid during periods of maximum fertilizer production. These net power values include all project-wide power generation and power consumption sources, including the power consumption of the third-party owned air separation unit and the power consumption required by OEHI for CO_2 compression/injection/recovery/re-injection for EOR and, ultimately, carbon sequestration.

The EHOF is approximately 48,000 acres and is located southwest of Bakersfield and south of the City of Buttonwillow in Western Kern County. The EHOF is immediately south of the Lakern Area of Critical Environmental Concern (ACEC), including 3,111 acres controlled by the Bureau of Land Management. Approximately 2,050 acres of this surrounding area is managed as various conservation areas by the Center for Natural Lands Management and OEHI Habitat Management Lands. The remainder is owned by Chevron Corporation and other companies. McKittrick Valley and portions of Buena Vista Valley are to the west. Ten miles west of the site is another ACEC approximately 199,030 acres in size. To the south is the Buena Vista Valley the majority of which is another oil field. The city of Taft is approximately seven miles south of the EHOF. Land to the east includes the Coles Levee Ecological Preserve (6,059 acres), Kern Water Bank Authority (19,900 acres), Tule Elk Reserve State Park and the Kern River.

This analysis evaluates the expected air quality impacts from the emissions of criteria air pollutants from both the construction and operation of HECA including the use of CO_2 for enhanced oil recovery and sequestration at the EHOF. Criteria air pollutants are defined as air contaminants for which the state and/or federal governments, per the California Clean Air Act and federal Clean Air Act respectively, have established ambient air quality standards to protect public health.

The criteria pollutants analyzed within this section are nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), ozone (O_3), particulate matter (PM) and lead (Pb). Additional pollutants are regulated under federal and state programs, including hazardous air pollutants (HAPS) and toxic air contaminants (TACS). Therefore emissions from HAPS and TACS such as mercury (Hg) and hydrogen sulfide (H_2S) will be quantified to determine compliance with regulatory requirements. Potential health impacts from these pollutants will be analyzed in the **Public Health** Section of this document.

Particulate matter is categorized into two subsets, inhalable particulate matter less than 10 microns in diameter (PM10) and fine particulate matter less than 2.5 microns in diameter (PM2.5). Nitrogen oxides (NOx, consisting primarily of nitric oxide [NO] and NO_2) and volatile organic compound (VOC) emissions readily react in the atmosphere as precursors to ozone and, to a lesser extent, particulate matter. SOx readily react in the atmosphere to form particulate matter and are major contributors to acid rain. The terms nitrogen oxides (NOx) and SOx are also used when discussing these two pollutants.

In carrying out the analysis, the California Energy Commission (Energy Commission) staff evaluated the following three major issues:

- Whether HECA is likely to conform with applicable federal, state and SJVAPCD air quality laws, ordinances, regulations and standards (Title 20, California Code of Regulations, section 1744 (b));
- Whether HECA is likely to cause significant air quality impacts, including new violations of ambient air quality standards or contribute to existing violations of those standards (Title 20, California Code of Regulations, section 1742 (b)); and
- Whether the mitigation measures proposed for HECA are adequate to lessen the potential impacts to a less than significant level (Title 20, California Code of Regulations, section 1742 (b)).

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The applicable laws, ordinances, regulations and standards for HECA and the associated OEHI CO_2 EOR component are both detailed below.

HECA

The federal, state, and local laws and policies applicable to the control of criteria pollutant emissions and mitigation of air quality impacts for HECA are summarized in **Air Quality Table 1**. Staff's analysis examines the project's compliance with these requirements.

Air Quality Table 1
HECA
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	**U.S. Environmental Protection Agency**
40 CFR 50	National Ambient Air Quality Standards (NAAQS).
40 CFR 51	New Source Review (NSR) – Requires NSR permit(s) for new stationary sources. This requirement is addressed through SJVAPCD Rule 2201, with the exception of PM2.5 NSR (100 ton/year trigger), that is not currently included in SJVAPCD Rule 2201.

40 CFR 52.21	Prevention of Significant Deterioration (PSD) – Requires dispersion modeling to demonstrate there is no violation of NAAQS or PSD increments, for pollutants that attain the NAAQS.
40 CFR 60, Subpart A	General Provisions - Outlines general requirements for facilities subject to standards of performance including, notification, work practice, monitoring and testing requirements.
40 CFR 60, Subpart Db	Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units [40 CFR Part 60 - New Source Performance Standards (NSPS)] - Requires monitoring, notification, and reporting of emissions and operation of the proposed natural gas fired auxiliary boiler.
40 CFR 60, Subpart Ga	Standards of Performance for Nitric Acid Plants for Which Construction, Reconstruction, or Modification Commenced After October 14, 2011 - Limits exhaust nitrogen oxide content based on production.
40 CFR 60, Subpart Y	Standards of Performance for Coal Preparation and Processing Plants - Requires dust collector particulate matter source testing, visual emissions testing and visual monitoring of equipment, and recordkeeping for coal handling, storage, and emission control equipment.
40 CFR 60, Subpart IIII	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines - Requires the proposed emergency engines to achieve specific emission standards depending on the size and model year of the engine.
40 CFR 60, Subpart KKKK	Standards of Performance for Stationary Combustion Turbines - Replaces Subparts Da and GG for the proposed combustion turbines and duct burners with heat recovery steam generators. Requires proposed combined cycle units to achieve 15 ppm NOx and achieve fuel sulfur standards.
40 CFR 63, Subpart ZZZZ	National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines - Establishes emission limitations and operating limitations for internal combustion (IC) engines located at major and area sources of HAP emissions.
40 CFR 63, Subpart UUUUU	National Emission Standards for Hazardous Air Pollutants: Coal-And Oil-Fired Electric Utility Steam Generating Units - Establishes emission limitations, work place standards for hazardous air pollutants as well as compliance requirements.
40 CFR 70, CAA Sec 401, 42 USC 7661	Federal Title V Operating Permit Program - Consolidates federally-enforceable operating limits. An application is required within one year following the start of operation. This program is within the jurisdiction of the SJVAPCD with U.S. EPA oversight [SJVAPCD Rule 2520].
40 CFR 72, CAA Sec 401 42 USC 7651	Title IV Acid Rain – Applicable to electrical generating units greater than 25 MW. Requires a Title IV permit and compliance with acid rain provisions, implemented through the Title V program. This program is within the jurisdiction of the SJVAPCD with U.S. EPA oversight [SJVAPCD Rule 2540].
40 CFR Part 93 General Conformity	Requires a determination of conformity with State Implementation Plans for projects requiring federal approvals if a project's annual emissions are above specified levels.

State	**California Air Resources Board and Energy Commission**
Health and Safety Code (HSC) Section 44300-44384; Title 17 of The California Code of Regulations (17 CCR 93300-93300.5) Toxic "Hot Spots"	Requires preparation and biennial updating of facility emission inventory of hazardous substances; health risk assessments.

Acts	
Health and Safety Code (HSC) Section 40910-40930	Permitting of source needs to be consistent with approved clean air plans. The SJVAPCD New Source Review (NSR) program is consistent with regional air quality management plans.
California Health & Safety Code Section 41700	Public Nuisance Provisions. Outlaws the discharge of air contaminants that cause nuisance, injury, detriment, or annoyance.
California Public Resources Code 25523(a); 20 CCR 1752, 2300, 2309 and DIV. 2, Chap. 5, Art. 1, Appendix B, Park (k)	Requires that the Energy Commission decision on the Application For Certification (AFC) include requirements to assure protection of environmental quality; AFC is required to address air quality protection.
California Code of Regulations (CCR) 17 CCR § 93115	Airborne Toxics Control Measure for Stationary Compression Ignition Engines. Limits types of fuels allowed, establishes maximum emission rates and establishes recordkeeping requirements for stationary compression ignition engines, including emergency generator and fire water pump engines.
California Code of Regulations (CCR) 13 CCR § 2485	Airborne Toxics Control Measure to Limit Diesel-Fueled Commercial Motor Vehicle Idling. Generally prohibits idling longer than five minutes for diesel-fueled commercial motor vehicles.
California Code of Regulations (CCR) 13 CCR § 2449	In-Use Off-road Diesel Vehicle Regulation. Imposes idling limits of five minutes, requires a plan for emissions reductions for medium to large fleets, requires all vehicles with engines greater than 25 horsepower to be reported to the California Air Resources Board (CARB) and labeled, and restricts adding older vehicles into fleets.

Local	**San Joaquin Valley Air Pollution Control District**
Regulation I, General Provisions	Establishes the requirements and standards for stack monitoring (Rule 1080), source sampling (Rule 1081), and breakdown events (Rule 1100) and identifies penalties.
Regulation II, Permits	Establishes the regulatory framework for permitting new and modified sources. Included in these requirements are the federally-delegated requirements for NSR, the Title V Operating Permit Program, and the Title IV Acid Rain Program.
Rule 2010, Permits Required	Requires any person constructing, altering replacing or operating any source operation which emits, may emit, or may reduce emissions to obtain an Authority to Construct or a Permit to Operate, unless exempted by Rule 2020.
Rule 2201, New and Modified Stationary Sources	Establishes the pre-construction review requirements for new, modified or relocated emission sources, in conformance with NSR to ensure that these facilities do not interfere with progress in attainment of the ambient air quality standards and that future economic growth in the San Joaquin Valley is not unnecessarily restricted. Establishes the requirement to prepare a Preliminary Determination of Compliance (PDOC) and Final Determination of Compliance (FDOC) during District review of an application for a power plant for power plants under Energy Commission jurisdiction. This regulation establishes Best Available Control Technology (BACT) and emission offset requirements.
Rule 2410, Prevention of Significant Deterioration	Incorporates federal Prevention of Significant Deterioration (PSD) program requirements for new major sources in areas that are in attainment or unclassified for a criteria pollutant. The PSD requirements will be incorporated into the Determination of Compliance.
Rule 2520, Federally Mandated Operating Permits	Establishes the permit application and compliance requirements for the federal Title V federal permit program. HECA qualifies as a Title V facility and must submit a Title V application within twelve months after starting operation.
Rule 2540, Acid Rain Program	Implements the federal Title IV Acid Rain Program, which requires

	subject facilities to obtain emission allowances for SOx emissions and requires fuel sampling and/or continuous monitoring to determine SOx and NOx emissions.
Rule 2550, Federally Mandated Preconstruction Review for Major Sources of Air Toxics	Establishes requirements for new or reconstructed facilities classified as a major air toxics source.
Rule 4001, New Source Performance Standards	Specifies that a project must meet the requirements of the Federal New Source Performance Standards (NSPS), according to Title 40, Code of Federal Regulations, Part 60. The specific NSPS subparts that are applicable to HECA include: • Subpart A - General Provisions • Subpart Db - Standards of Performance for Small Industrial-Commercial Institutional Steam Generating Units • Subpart Ga - Standards of Performance for Nitric Acid Plants for Which Construction. Reconstruction, or Modification Commenced After October 14, 2011 • Subpart GG – Standards of Performance for Stationary Gas Turbines • Subpart Y - Standards of Performance for Coal Preparation and Processing Plants • Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines • Subpart KKKK - Standards of Performance for Stationary Combustion Turbines
Rule 4002, National Emission Standards for Hazardous Air Pollutants	Incorporates the National Emission Standards for Hazardous Air Pollutants from Part 61 and Part 63, Chapter I, Subpart C, Title 40 CFR and applies to major sources of HAPs. Subpart UUUUU applies to the electrical generating unit, and Subpart ZZZZ applies to the emergency engines.
Rule 4101, Visible Emissions	Prohibits visible air emissions, other than water vapor, of more than No. 1 on the Ringelmann chart (20 percent opacity) for more than three minutes in any one-hour.
Rule 4102, Nuisance	Prohibits any emissions which cause injury, detriment, or public nuisance.
Rule 4201-4202, Particulate Matter	Limits particulate emissions from any source that emits or may emit dust, fumes, or total suspended particulate matter.
Rule 4301, Fuel Burning Equipment	Limits the concentrations of combustion contaminants and specified emission rates from any fuel burning equipment.
Rule 4304, Equipment Tuning Procedure for Boilers, Steam Generators and Process Heaters	Provides equipment tuning procedures for boilers, steam generators and process heaters to control visible emissions and emissions of both NOx and CO.
Rule 4351, 4305-4306, Boilers, Steam Generators and Process Heaters –Phase 1, 2 & 3	Limits NOx, CO, SO_2, and PM10 from gaseous/liquid fueled boilers, steam generators, and process heaters.
Rule 4311, Flares	Limits NOx, VOC, and SOx from the operation of flares.
Rule 4320, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/Hr	Limits NOx, CO, SO_2, and PM10 from gaseous/liquid boilers, steam generators, and process heaters.
Rule 4701-4702, Internal Combustion Engines – Phase 1 & 2	Limits emissions of NOx, CO, and VOC from internal combustion engines. However, as emergency units, the proposed emergency engine-generator set and emergency fire water pump engine are exempt from emission limits, subject to monitoring and

	recordkeeping.
Rule 4703, Stationary Gas Turbines	Limits the proposed stationary gas turbine emissions of NOx to 3 ppmv and CO to 25 ppmv over a 3-hour averaging period. Provided certain demonstrations are made, the emission limits do not apply during startup, shutdown, or reduced load periods (defined as "transitional operation periods").
Rule 4801, Sulfur Compounds	Limits SOx emissions to no greater than 0.2 percent by volume calculated as SO_2 on a dry basis averaged over 15 consecutive minutes.
Rule 7012, Hexavalent Chromium	Limits emissions of hexavalent chromium from circulating water in cooling towers.
Regulation VIII, Fugitive PM10 Prohibition	Sets forth the requirements and performance standards for the control of emissions from fugitive dust causing activities.
Rule 9110, General Conformity	Specifies criteria and procedures for determining the conformity of federal actions with the SJVAPCD's air quality implementation plan.

OEHI CO_2 EOR Component

The federal, state, and local laws and policies applicable to the control of criteria pollutant emissions and mitigation of air quality impacts for the OEHI CO_2 EOR component are summarized in **Air Quality Table 2**. Staff's analysis provides a preliminary examination of the proposed OEHI CO_2 EOR component's compliance with these requirements in order to determine whether there are any potentially significant adverse impacts.

Air Quality Table 2
OEHI CO_2 EOR Component
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	**U.S. Environmental Protection Agency**
40 CFR 50	National Ambient Air Quality Standards (NAAQS).
40 CFR 51	New Source Review (NSR) – Requires NSR permit for new and modified stationary sources. This requirement is addressed through SJVAPCD Rule 2201, with the exception of PM2.5 NSR (100 ton/year trigger), that is not currently included in SJVAPCD Rule 2201.
40 CFR 52.21	Prevention of Significant Deterioration (PSD) – Requires dispersion modeling to demonstrate no violation of NAAQS or PSD increments, for pollutants that attain the NAAQS.
40 CFR 60, Subpart IIII	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. Requires proposed emergency engines to achieve specific emission standards depending on the size and model year of the engine.
40 CFR 70, CAA Sec 401, 42 USC 7661	Federal Title V Operating Permit Program. Consolidates federally-enforceable operating limits. Application required within one year following start of operation. This program is within the jurisdiction of the SJVAPCD with U.S. EPA oversight [SJVAPCD Rule 2520].

State	**California Air Resources Board and Energy Commission**
Health and Safety Code (HSC) Section 44300-44384; Title 17 of The California Code of Regulations (17 CCR 93300-93300.5) Toxic "Hot Spots" Acts	Requires preparation and biennial updating of facility emission inventory of hazardous substances; health risk assessments.

Health and Safety Code (HSC) Section 40910-40930	Permitting of source needs to be consistent with approved clean air plans. The SJVAPCD New Source Review (NSR) program is consistent with regional air quality management plans.
California Health & Safety Code Section 41700	Public Nuisance Provisions. Outlaws the discharge of air contaminants that cause nuisance, injury, detriment, or annoyance.
California Code of Regulations (CCR) 17 CCR § 93115	Airborne Toxics Control Measure for Stationary Compression Ignition Engines. Limits the types of fuels allowed, establishes maximum emission rates, and establishes recordkeeping requirements on stationary compression ignition engines, including emergency generator and fire water pump engines.
California Code of Regulations (CCR) 13 CCR § 2485	Airborne Toxics Control Measure to Limit Diesel-Fueled Commercial Motor Vehicle Idling. Generally prohibits idling longer than five minutes for diesel-fueled commercial motor vehicles.
Local	**San Joaquin Valley Air Pollution Control District**
Regulation I, General Provisions	Establishes requirements and standards for stack monitoring (Rule 1080), source sampling (Rule 1081), and breakdown events (Rule 1100) and identifies penalties.
Regulation II, Permits	Establishes the regulatory framework for permitting new and modified sources. Included in these requirements are the federally-delegated requirements for NSR, the Title V Operating Permit Program, and the Title IV Acid Rain Program.
Rule 2201, New and Modified Stationary Sources	Establishes the pre-construction review requirements for new, modified or relocated emission sources, in conformance with NSR to ensure that these facilities do not interfere with progress in attainment of the ambient air quality standards and that future economic growth in the San Joaquin Valley is not unnecessarily restricted. This regulation establishes Best Available Control Technology (BACT) and emission offset requirements.
Rule 2250, Permit Exempt equipment Registration	Provides a mechanism to determine compliance of permit-exempt equipment with applicable rules and regulations.
Rule 2280, Portable Equipment Registration	Establishes standards for registrations of certain portable emission units for operation.
Rule 2520, Federally Mandated Operating Permits	Establishes the permit application and compliance requirements for the federal Title V federal permit program. HECA qualifies as a Title V facility and must submit the Title V application within twelve months after starting operation.
Rule 2530, Federally Enforceable Potential to Emit	Restricts potential to emit of a stationary source so the source may be exempt from the requirements of Rule 2520 (Federally Mandated Operating Permits).
Rule 2550, Federally Mandated Preconstruction Review for Major Sources of Air Toxics	Establishes requirements for new or reconstructed facilities classified as a major air toxics source.
Rule 4001, New Source Performance Standards	Specifies that a project must meet the requirements of the Federal New Source Performance Standards (NSPS), according to Title 40, Code of Federal Regulations, Part 60. The specific NSPS subpart that is applicable to the OEHI CO_2 EOR component is Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.
Rule 4002, National Emission Standards for Hazardous Air Pollutants	Incorporates the National Emission Standards for Hazardous Air Pollutants from Part 61 and Part 63, Chapter I, Subpart C, Title 40 CFR. Applies to major sources of HAPs, and Subpart ZZZZ applies to the emergency engines.
Rule 4101, Visible Emissions	Prohibits visible air emissions, other than water vapor, of more than No. 1 on the Ringelmann chart (20 percent opacity) for more than three minutes in any one-hour.
Rule 4102, Nuisance	Prohibits any emissions which cause injury, detriment, or public

	nuisance.
Rule 4201-4202, Particulate Matter	Limits particulate emissions from any source that emits or may emit dust, fumes, or total suspended particulate matter.
Rule 4301, Fuel Burning Equipment	Limits the concentrations of combustion contaminants and specified emission rates from any fuel burning equipment.
Rule 4304, Equipment Tuning Procedure for Boilers, Steam Generators and Process Heaters	Provides equipment tuning procedures for boilers, steam generators and process heaters to control visible emissions and emissions of both NOx and CO.
Rule 4351, 4305-4308, Boilers, Steam Generators and Process Heaters –Phase 1, 2 & 3	Limits NOx, CO, SO_2, and PM10 from gaseous/liquid fueled boilers, steam generators, and process heaters.
Rule 4311, Flares	Limits NOx, VOC, and SOx from the operation of flares.
Rule 4320, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/Hr	Limits NOx, CO, SO_2, and PM10 from gaseous/liquid boilers, steam generators, and process heaters.
Rule 4701-4702, Internal Combustion Engines – Phase 1 & 2	Limits emissions of NOx, CO, and VOC from internal combustion engines. However, as emergency units, the proposed emergency engine-generator set and emergency fire water pump engine are exempt from emission limits, subject to monitoring and recordkeeping.
Rule 4801, Sulfur Compounds	Limits SOx emissions to no greater than 0.2 percent by volume calculated as SO_2 on a dry basis averaged over 15 consecutive minutes.
Regulation VIII, Fugitive PM10 Prohibition	Sets forth the requirements and performance standards for the control of emissions from fugitive dust causing activities.

Air Quality Table 2 above presents staff's current understanding of the OEHI CO_2 EOR component and the related applicable air quality regulations. Any EOR project using CO_2 from HECA is expected to undergo a separate CEQA analysis and would undergo a separate air quality permitting analysis, assuming that HECA is granted a license by the Energy Commission.

SETTING

METEOROLOGICAL CONDITIONS

The climate in California is typically dominated by the eastern Pacific high-pressure system centered off the coast of California. In the summer, this system results in low inversion layers and clear skies inland and typically early morning fog by the coast. In winter, this system promotes wind and rainstorms originating in the Gulf of Alaska and striking Northern California.

The climate of the southern San Joaquin Valley where the proposed project would be located is characterized by hot dry summers and mild winters with precipitation almost exclusively in the winter. Very little precipitation occurs during the summer months because the Pacific high-pressure ridge blocks migrating storm systems. Beginning in the fall and continuing through the winter, the storm belt and zone of strong westerly winds begins to greatly influence California. Temperature, winds, and rainfall are variable during fall and winter months, and stagnant conditions occur more frequently than during summer months.

Wind speeds are generally higher in summer than in winter and are typically north-northwesterly winds. During the spring, summer, and fall, the stronger winds are caused by a combination of offshore and thermal low pressure resulting from high temperatures in the Central Valley. During the winter months, winds are more variable. Calm conditions occur more during winter, but are relatively infrequent throughout the year. Valley fog often occurs during these calm, stagnant atmospheric conditions, when temperature inversions trap a layer of cool, moist air near the surface. The annual rainfall in the Tupman area is less than 7 inches and over 90 percent of the precipitation occurs during October through April. Summers are very warm with average daily peak high temperatures of 97°F and 96°F for the months of July and August, respectively. During December and January, the average daily low temperatures are 35°F and 37°F, respectively (WC 2013).

Along with the wind flow, the atmospheric stability and mixing heights are important factors in the determination of pollutant dispersion. Atmospheric stability is an indicator of the air turbulence and mixing. During the daylight hours of the summer when the earth is heated and air rises, there is more turbulence, more mixing, and thus less stability. During these conditions there is more air pollutant dispersion and therefore usually reduced air quality impacts near any single air pollution source. However, during the winter months between storms very stable atmospheric conditions with lower mixing heights and lower mean wind speeds can occur, resulting in very little mixing. Under these conditions, minimal air pollutant dispersion occurs, and consequently higher air quality impacts may result near air pollution emission sources.

SENSITIVE RECEPTORS

The general population includes many sensitive subgroups that may be at greater risk from exposure to emitted pollutants. These sensitive subgroups include the very young, the elderly, and those with existing illnesses. In addition, the location of the population in the area surrounding a project site may have a large bearing on health risk. The nearest non-residential sensitive receptor (Elk Hills Elementary School) for the HECA site is located approximately 2.5 miles southeast of the project site in Tupman. There are a few farm residences that surround the site location. Two residences and the Tule Elk Preserve State Park (which can attract visits by potentially sensitive subpopulations including people of advanced age and children) are located within one mile of the IGCC main complex on the project site, with the closest residence being approximately 1,400 feet east of the project site.

EXISTING AMBIENT AIR QUALITY

The Federal Clean Air Act and the California Clean Air Act both require the establishment of standards for ambient concentrations of air pollutants, called ambient air quality standards (AAQS). The state AAQS, established by the California Air Resources Board, are typically lower (more protective) than the federal AAQS, which are established by the United States Environmental Protection Agency (U.S. EPA). The current state and federal air quality standards are listed in **Air Quality Table 3**. The averaging times for the various air quality standards, the times over which they are measured, range from one-hour to an annual average. The standards are read as a concentration, in parts per million (ppm), or as a weighted mass of material per a volume of air, in milligrams or micrograms of pollutant in a cubic meter of air (mg/m^3 or $\mu g/m^3$, respectively). The U.S. EPA revised the PM2.5 annual standard from 15 $\mu g/m^3$ down to 12 $\mu g/m^3$ in December 2012, but the former NAAQS remains applicable for the analysis of this project because U.S. EPA allows the grandfathering of permit applications that were deemed complete prior to December 2012 However, the area is classified as nonattainment as described more fully below, regardless of whether the 12 or at 15 $\mu g/m^3$ standard is used.

In general, an area is designated as attainment if the concentration of a particular air contaminant does not exceed the standard. Likewise, an area is designated as nonattainment for an air contaminant if that contaminant standard is violated. Exceptional events that are out of human control that create very high pollutant concentrations such as wind storms and fires are generally excluded from attainment designations. In circumstances where there is not enough ambient data available to support designations as either attainment or nonattainment, the area can be designated as unclassified or unclassifiable. The unclassified area is normally treated the same as an attainment area for regulatory purposes. In addition, an area could be designated as attainment for one air contaminant and nonattainment for another, or attainment for the federal standard and nonattainment for the state standard for the same air contaminant.

The project site is located in western Kern County within the SJVAB and is under the jurisdiction of the SJVAPCD. Western Kern County in the SJVAB is designated as nonattainment for the federal and state ozone standards, the state PM10 standard, and the federal and state PM2.5 standards. This area is designated as attainment or unclassified for the state and federal CO, SO_2, lead (particulate), federal PM10 and NO_2, and state NO_2, H_2S, SO_4, visibility reducing particulates and vinyl chloride standards. **Air Quality Table 4** summarizes the area's attainment status for various applicable state and federal standards. The ambient air quality standards that staff uses as a basis for determining project significance are health-based standards. They are set at levels to adequately protect the health of all members of the public, including those most sensitive to adverse air quality such as the aged, people with existing illnesses, and infants and children, while providing a margin of safety.

The determination of appropriate and representative background concentrations needs to consider the location of the project site, the regional context of the site, the location of available monitoring stations, and the data available from those monitoring stations. Background concentrations are not used to categorize the general air quality of an air basin. Instead, the general air quality in an air basin is based on worst-case monitoring data in that air basin. This worst case monitoring data is the basis for the SJVAB designations presented in **Air Quality Table 4**. Background concentrations are used to determine the worst-case air quality concentrations in the local vicinity where the proposed project may cause an impact. These background concentrations are used in impact analyses to allow a determination of the additive impacts of a project that would occur at and downwind of the project's site fence or otherwise in the near-field where the general public has access. The proposed site for the HECA facility is a predominantly agricultural area in western Kern County, approximately 2.5 miles northwest of the unincorporated community of Tupman and approximately 7 miles from the western border of the city of Bakersfield. This project site is located on the western side of the San Joaquin Valley in a rural area that is not located downwind of a major urban area. Therefore, the use of monitoring stations that are both more distant from the project site and that exist in a different regional context than the project site, such as the Arvin monitoring station that is on eastern side of the valley and is immediately downwind of Bakersfield, the largest urban area in the southern San Joaquin Valley, would not be representative for the determination of background values for the area that would be impacted by this project.

Air Quality Table 3
Federal and State Ambient Air Quality Standards [a, b]

Pollutant	Averaging Time	Federal Standard	California Standard
Ozone (O_3)	8 Hour	0.075 ppm (147 μg/m^3)	0.070 ppm (137 μg/m^3)
	1 Hour	--	0.09 ppm (180 μg/m^3)
Carbon Monoxide (CO)	8 Hour	9 ppm (10 mg/m^3)	9.0 ppm (10 mg/m^3)
	1 Hour	35 ppm (40 mg/m^3)	20 ppm (23 mg/m^3)
Nitrogen Dioxide [c] (NO_2)	Annual	0.053 ppm (100 μg/m^3)	0.03 ppm (57 μg/m^3)
	1 Hour	0.100 ppm	0.18 ppm (339 μg/m^3)
Sulfur Dioxide [d] (SO_2)	24 Hour	--	0.04 ppm (105 μg/m^3)
	3 Hour	0.5 ppm (1,300 μg/m^3)	--
	1 Hour	0.075 ppm	0.25 ppm (655 μg/m^3)
Particulate Matter (PM10)	Annual	--	20 μg/m^3
	24 Hour	150 μg/m^3	50 μg/m^3
Fine Particulate Matter (PM2.5)	Annual	15 [h] μg/m^3	12 μg/m^3
	24 Hour	35 μg/m^3	--
Lead [e,f]	30 Day Average	--	1.5 μg/m^3
	Calendar Quarter	1.5 μg/m^3	--
	Rolling 3-Month Average	0.15 μg/m^3	--
Visibility Reducing Particulates	8 Hour	--	See footnote g
Sulfates (SO_4)	24 Hour	--	25 μg/m^3
Hydrogen Sulfide (H_2S)	1 Hour	--	0.03 ppm (42 μg/m^3)
Vinyl Chloride [e] (chloroethene)	24 Hour	--	0.01 ppm (26 μg/m^3)

Source: ARB 2013b.

Notes: [a] California standards for ozone, carbon monoxide, sulfur dioxide (1 and 24 hour), nitrogen dioxide, and particulate matter (PM10, PM2.5 and visibility reducing particles are values that are not to be exceeded. All others are not to be equaled or exceeded.)

[b] National standards (other than ozone, 1-hour NO_2, particulate matter and those based on annual arithmetic mean) are not to be exceeded more than once a year. The ozone standard is attained when the fourth highest 8-hour concentration measured at each site in a year averaged over three years is equal or less than the standard. For PM10, the 24-hour standard is attained when the expected number of days per calendar year with a 24-hour average concentration above 150 μg/m^3 is equal or less than one. For PM2.5, the 24-hour standard is attained when 98 percent of the daily concentrations, averaged over three years are equal or less than the standard.

[c] To attain the 1-hour national standard, the 3-year average of the annual 98th percentile of the 1-hour daily maximum concentrations at each site must not exceed 100 ppb (0.100 ppm).

[d] On June 2, 2010, a new 1-hour SO_2 standard was established and the existing 24-hour and annual primary standards were revoked. To attain the 1-hour standard, the 3-year average of the annual 99th percentile of the 1-hour daily maximum concentrations at each site must not exceed 75 ppb (0.075 ppm). The 1971 SO_2 national standards (24-hour and annual) remain in effect until 1 year after the area is designated for the 2010 standard, except that in areas designated non-attainment for the 1971 standards. The 1971 standards remain in effect until implementation plans to attain or maintain the 2010 standards are approved by U.S. EPA.

[e] The ARB has identified lead and vinyl chloride as “toxic air contaminants” with no threshold level exposure for adverse health effects determined. These actions allow for the implementation of control measures at levels below the ambient concentrations specified for these pollutants.

[f] The national standard for lead was revised on October15, 2008 to a rolling 3-month average. The 1978 lead standard (1.5 μg/m^3 as a quarterly average) remains in effect until 1 year after an area is designated for the 2008 standard, except that in areas designated non-attainment for the 1978 standard, the 1978 standard remains in effect until implementation plans to attain or maintain the 2008 are approved.

[g] In 1989, the ARB converted both the general statewide 10-mile visibility standard and the Lake Tahoe 30-mile visibility standard to instrumental equivalents, which are “extinction of 0.23 per kilometer” and “extinction of 0.07 per kilometer” for the statewide and Lake Tahoe Air Basin standards, respectively.

[h] The current federal annual standard is 12 μg/m$^{3.}$ However, this project will be evaluated for compliance with the previous federal annual standard of 15 μg/m^3 due to the date the HECA application was deemed complete by the SJVAPCD.

Air Quality Table 4
Federal and State Attainment Status for the San Joaquin Valley

Pollutant	Attainment Status	
	Federal	**State**
Ozone – 1 hour	No Federal Standard [a]	Nonattainment/Severe
Ozone – 8 hour	Nonattainment/Extreme [b]	Nonattainment
PM10	Attainment [c]	Nonattainment
PM2.5	Nonattainment	Nonattainment
CO	Attainment/Unclassified	Attainment/Unclassified
NO_2	Attainment/Unclassified [d]	Attainment
SO_2	Attainment/Unclassified	Attainment
Lead (particulate)	No Designation/Classification	Attainment
H_2S	No Federal Standard	Unclassified
SO_4	No Federal Standard	Attainment
Visibility Reducing Particulates	No Federal Standard	Unclassified
Vinyl Chloride	No Federal Standard	Nonattainment

Source: SJVAPCD 2013b, U.S. EPA 2013a
Notes:
[a] Effective June 15, 2005, the U.S. EPA revoked in the federal 1-hour ozone standard, including associated designations and classifications. However, U.S. EPA had previously classified the SJVAB as extreme nonattainment for this standard. EPA approved the 2004 Extreme Ozone Attainment Demonstration Plan on March 8, 2010 (effective April 7, 2010). Many applicable requirements for extreme 1-hour ozone nonattainment areas continue to apply to the SJVAPCD.
[b] Initially classified as serious nonattainment for the 1997 8-hour ozone standard, EPA approved a reclassification to extreme nonattainment in the Federal Register on May 5, 2010 (effective June 4, 2010).
[c] On September 25, 2008, U.S. EPA redesignated the San Joaquin Valley to attainment for the PM10 National Ambient Air Quality Standard (NAAQS) and approved the PM10 Maintenance Plan.
[d] On February 17, 2012, U. S. EPA designated the entire United States as "unclassifiable/attainment" for the new federal 1-hour NO_2 standard, effective February 29, 2012.

The monitoring station located closest to the proposed project site is the Shafter-Walker Street (Shafter) station, which is approximately 13 miles northeast of the project site. The Shafter station is operated by the ARB and is 18 miles northwest of Bakersfield. This station monitors ozone, NO_2 and VOCs (non-methane organic compounds (NMOCs) and non-methane hydrocarbons [NMHC]). The monitoring site is classified as a Type 1 Photochemical Assessment Monitoring Station (PAMS). The objective of this type of site is to provide background ozone concentrations. Therefore, the monitor is located upwind from Bakersfield to establish concentrations that are presumed to not be influenced by nearby urban emissions (SJVAPCD 2011).

The Bakersfield-5558 California Avenue monitoring station is located approximately 20 miles east of the project site. This station monitors ozone, PM10, PM2.5, NO_2, toxics and hexavalent chromium (Cr^{6+}). This station is closer to the southern end of the San Joaquin Valley and has mountains to the east, west and south. The mountains impede air flow so pollutants can get trapped and accumulate in the area. This station is operated by ARB and is located in the Bakersfield metropolitan area. The objective of this site is to monitor representative pollutant concentrations in an urban area.

The Bakersfield Golden Highway monitoring station is located approximately 21 miles east of the project site, but was closed early in 2010. This station measured CO. Data is available until 2010; however 2010 only includes limited data from January. There is data from the Bakersfield-5558 California Avenue station spanning 2002-2005 and also limited data in 2011. The 2011 data includes preliminary data from October only.

The Fresno First Street monitoring station, located approximately 100 miles to the north northwest, is the only ambient pollutant monitoring station within the SJVAB which currently measures SO_2. This station is operated by ARB and is located in Fresno. The purpose of this site is to monitor representative pollutant concentrations in an urban area. Historical SO_2 data exists from other stations in Kern County; however, the latest data collected dates back to 2001 and before.

Air Quality Table 5 summarizes the historical air quality data that staff determined is

Air Quality Table 5
Criteria Pollutant Summary
Maximum Ambient Concentrations (ppm or µg/m^3)

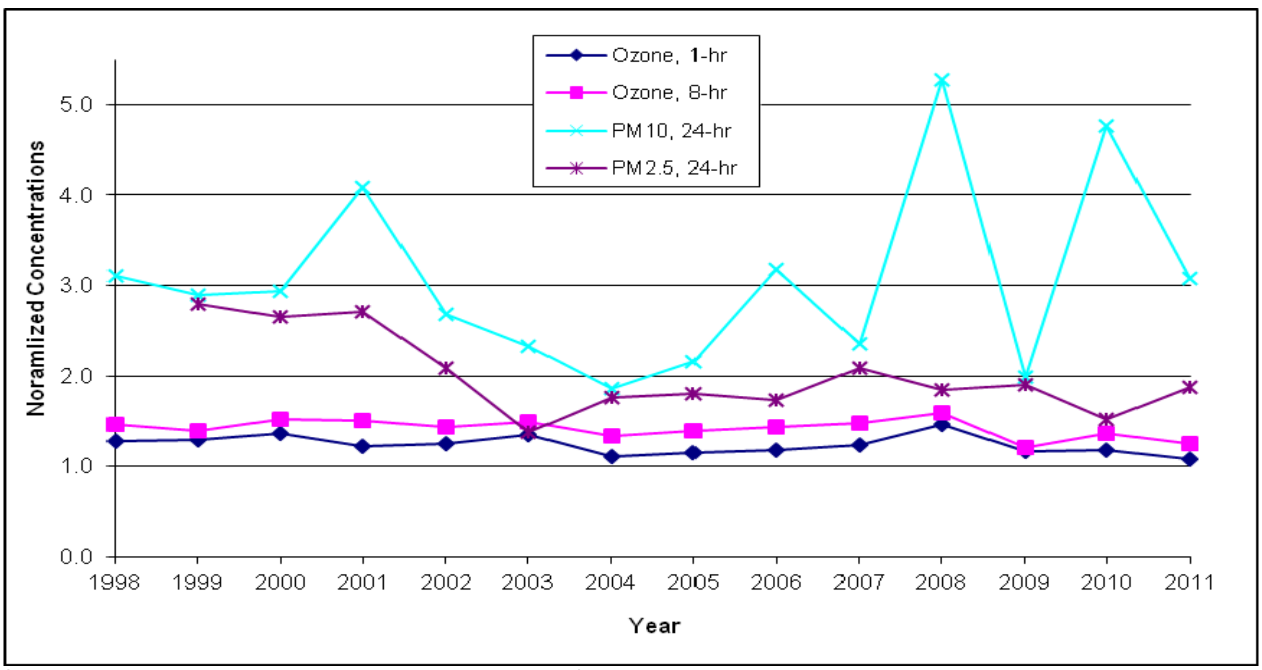
Pollutant	Averaging Period	Units	2006	2007	2008	2009	2010	2011	AAQS
ARB Website Data									
Ozone	1 hour	ppm	0.106	0.111	0.131	0.105	0.106	0.097	0.09
Ozone	8 hour	ppm	0.100	0.103	0.111	0.084	0.095	0.087	0.07
PM10 [a]	24 hour	µg/m^3	159	118	263	99	238	154	50
PM10 [a]	Annual	µg/m^3	48.4	48.5	55.3	41.2	32.6	44.2	20
PM2.5 [a, c]	Annual	µg/m^3	21.6	22.0	21.9	21.2	17.2	18.1	12
CO	1 hour	ppm	3.3	2.8	3.5	2.2	ND	ND	20
CO	8 hour	ppm	2.19	1.97	2.17	1.51	ND	ND	9.0
NO_2	1 hour (State)	ppm	0.100	0.101	0.057	0.052	0.074	0.054	0.18
NO_2	Annual	ppm	0.019	0.014	0.014	0.012	0.012	0.013	0.03
SO_2	1 hour (State)	ppm	ND	0.024	0.012	0.013	0.015	0.016	0.25
SO_2	1 hour (Fed)[e]	ppm	ND	0.012	0.006	0.008	0.007	0.009	0.075
SO_2	24 hour	ppm	ND	0.007	0.003	0.005	0.004	0.004	0.04
U.S.EPA Website Data Relevant to Specific NAAQS									
Pollutant	**Averaging Period**	**Units**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**AAQS**
Ozone	8 hour	ppm	0.093	0.083	0.086	0.080	0.091	0.084	0.075
PM10	24 hour	µg/m^3	153	115	127	94	86	97	150
PM2.5 [a, b]	24 hour	µg/m^3	61	73	63	67	46	66	35
NO_2	1 hour (Fed)[d]	ppm	0.073	0.065	0.052	0.043	0.048	0.042	0.100

Source: ARB 2013b, U.S.EPA 2013b
ND = No data or insufficient data.
Notes:
[a] Exceptional PM concentration events, such as those caused by wind storms are not shown in the U.S.EPA data but are still included in the state data presented in the upper portion of this table.
[b] 24-hour PM2.5 data shown are the 98th percentile concentrations.
[c] Annual average PM2.5 data shown are National annual average for those years when state annual average data are not available.
[d] 1-hour federal NO_2 data are 98th percentile of daily 1-hour maximums.
[e] 1-hour federal SO_2 data are 99th percentile of daily 1-hour maximums.

most representative of the project location, recorded at Shafter-Walker Street station for ozone (2006-2011) and NO_2 (2006-2011), Bakersfield-5558 California Avenue for PM10 (2006-2011), PM2.5 (2006-2011), and CO (2006-2011). CO concentrations for the years 2006-2010 were recorded at the Bakersfield-Golden State Highway monitoring station. However, the availability of 2010 data from this station is limited. SO_2 data are collected from the Fresno-1st Street station for 2007-2011. Concentrations are provided based on ARB website summary data and U.S.EPA website summary data. The U.S.EPA website summary data that is provided in the table excludes exceptional events and also provides data that is relevant to the form of the NAAQS standard, such as 98th percentile of daily hourly maximum concentrations for the 1-hour NO_2 standard that is not available in the ARB website data.

In **Air Quality Figure 1**, short term normalized values are provided from 1998 to 2009. Normalized values represent the ratio of the highest measured concentrations in a given year to the most-stringent applicable national or state ambient air quality standard. Normalized values lower than one indicate that the measured concentrations were lower than the most-stringent ambient air quality standard while values above one indicate that concentrations from the monitoring station exceed the corresponding AAQS.

Air Quality Figure 1
Normalized Maximum Short-Term Historical Air Pollutant Concentrations*



Source: ARB 2013A. Normalized concentration is the ratio of the highest measured concentration to the applicable most stringent ambient air quality standard. For example, in 1999 the highest one-hour average ozone concentration measured at the Shafter Walker Street station was 0.116 ppm. Since the most stringent ambient air quality standard is the state standard of 0.09 ppm, the 1999 normalized concentration is 0.116/0.09 = 1.289.
* Shafter Walker Street monitoring station data (1998-2011) was used for all ozone values and Bakersfield-5558 California Avenue monitoring station (1998-2011) was used for PM10 and PM2.5.

Ozone (O_3)

Ozone is a colorless gas found in two regions of the atmosphere. In the upper region, it protects the earth from harmful rays from the sun. In the lower region, ozone is near the ground and forms what is generally called smog. Ozone is not directly emitted from stationary or mobile sources, but is formed as the result of chemical reactions in the atmosphere between nitrogen oxides (NOx) and hydrocarbons (Volatile Organic

Compounds [VOC]) in the presence of sunlight. Low precipitation levels, high temperatures and light winds are all conducive to elevated ozone levels.

Air Quality Table 4 and **Air Quality Figure 1** clearly show that ozone concentrations measured near the project site continue to violate the applicable standards. SJVAPCD is designated as extreme nonattainment for federal 8-hour ozone standard, severe nonattainment for the state 1-hour standard and nonattainment for the state 8-hour standard. The peak 1-hour and 8-hour ozone concentrations typically occur between May and September when ambient conditions are most favorable for the photochemical reactions that form ozone.

Nitrogen Dioxide (NO_2)

NO_2 is a component of a group of highly reactive gasses collectively known as NOx. NO_x is formed from the reaction of nitrogen and oxygen during combustion. Approximately 90 percent of the NOx emitted from combustion sources is in the form of nitric oxide (NO), while the balance is NO_2. NO is oxidized in the atmosphere by ozone to form NO_2, but some level of photochemical activity is needed for this conversion to occur. The highest concentrations of NO_2 typically occur during the fall. The winter atmospheric conditions can trap emissions near the ground level, but lacking significant photochemical activity (sun light), NO_2 levels are relatively low. In the summer the in-plume conversion rates of NO to NO_2 are high, but the relatively high temperatures and windy conditions disperse pollutants, preventing the accumulation of larger concentrations of NO_2.

The entire San Joaquin Valley Air Basin is classified as attainment for the state 1-hour NO_2 standard, unclassifiable/attainment for the 1-hour federal NO_2 standard and attainment for the annual federal NO_2 standard. EPA strengthened the ambient air quality standard for 1-hour NO_2 levels, effective April 12, 2010 and classified the entire United States as “unclassifiable/attainment” based upon data collected from 2008 to 2010, with the designation effective February 29, 2012. Once new, near-roadway monitoring stations based on population and traffic counts are in place and operational (expected in 2013) and sufficient data are collected, redesignation will be considered. The NO_2 concentrations in the project area continue to be well below both the state and federal ambient air quality standards.

Carbon Monoxide (CO)

Carbon monoxide (CO) is a colorless, odorless gas emitted from combustion processes. CO is a product of incomplete combustion primarily from mobile sources. The project site area within the SJVAB is classified as attainment for the state 1-hour and 8-hour CO standards. Past monitoring has indicated compliance and there are currently no minimum requirements for monitoring CO within the SJVAPCD. The highest concentrations of CO occur when low wind speeds and a stable atmosphere trap the pollution emitted at or near ground. The project area has a lack of significant mobile source emissions and based on Bakersfield monitoring stations, the local area has CO concentrations that are well below both the state and federal ambient air quality standards.

Particulate Matter (PM10) and Fine Particulate Matter (PM2.5)

Particulate matter with an aerodynamic diameter of less than 10 microns (PM10) and particulate matter with an aerodynamic diameter of less than 2.5 microns (PM2.5) can be emitted directly or it can be formed many miles downwind from emission sources when various precursor pollutants interact in the atmosphere.

The area is nonattainment of the state PM10 standards, attainment of the federal PM10 standards, and nonattainment of the state and federal PM2.5 standards. **Air Quality Figure 1** shows recent PM10 and PM2.5 concentration trends. The figure shows fluctuating concentration patterns, and shows clear exceedances of the state PM10 and state PM2.5 standards. It should be noted that an exceedance does not necessarily mean a violation or nonattainment, as exceptional events such as those caused by high winds or large wildfires may be determined by the regulatory community to not be violations.

Fine particulate matter, or PM2.5, is derived mainly from either the combustion of materials, or from precursor gases (SOx, NOx, and VOC) through complex reactions that form PM2.5 in the atmosphere. PM2.5 consists mostly of sulfates, nitrates, ammonium, elemental carbon, and a small portion of other organic and inorganic compounds.

Sulfur Dioxide (SO_2)

The SJVAB is classified as attainment for both state and federal SO_2 standards. The sulfur dioxide attainment status could change due to the new federal 1-hour standard; although a staff review of the air basin’s monitoring data suggest this would not occur for the SJVAB.

Sulfur dioxide is typically emitted as a result of the combustion of fuel containing sulfur; such as coal, oil, and to a much less extent natural gas and motor vehicle fuels. This project uses a high sulfur content fuel feedstock but the gasification process separates most of this into elemental sulfur which is not combusted and this greatly reduces the SO_2 pollution potential from this project’s emission sources.

Lead (Pb)

Lead is a naturally occurring metal that is soft and resistant to chemical corrosion. Lead forms compounds with both organic and inorganic substances. Lead has been used for many purposes for thousands of years and has accumulated in the environment. As an air pollutant, lead is present in small particles. Sources of lead emissions include industrial processes and emission from sources using coal and lead-based fuels such as aviation gas. In 1970, the ARB set the CAAQS for lead. In addition, the ARB has identified lead as a toxic air contaminant and is therefore involved in risk management activities for lead. In 1978, EPA set the NAAQS for lead. The NAAQS was substantially strengthened in 2008. Lead is monitored as a toxic substance at the Bakersfield-California site. The Bakersfield-California site is the most representative for lead concentrations for the proposed site due to the proximity of the Bakersfield-California monitor. However, the available lead concentration data is provided as 24-hour concentrations and not 30-day average, three-month rolling average, or quarterly average concentrations that are the basis of the AAQS, so that data has not been presented.

Lead is released from coal during combustion or gasification. Formation of lead is dependent on variables such as the lead species present in the coal, pretreatment of coal, gasification temperature and reaction time. Lead can be removed in plant particulate and acid gas cleanup systems. Due to the very low concentrations shown in the available ambient monitoring data and the low amount of lead emissions from this project it is assumed that the project would not create significant impacts based on the ambient lead standards. The Public Health Section provides additional information regarding the quantity of emissions and the health risks of the lead emissions from this project.

Hydrogen Sulfide (H_2S)

Hydrogen sulfide (H_2S) is a colorless, flammable gas that smells like rotten eggs. It is an impurity associated with natural gas and also results from the breakdown of organic matter in anaerobic conditions. During high temperature gasification of coal, sulfur is released and converted to H_2S. HECA proposes to remove the sulfur found in the feedstock with an acid gas removal system. H_2S concentrations have not been monitored in the San Joaquin Valley, other than at the former Bakersfield-Rio Bravo monitoring station for a short period at the end of 1983, so background concentrations for H_2S are not available for the San Joaquin Valley.

Other Toxics

Toxic air contaminants (TACs) and hazardous air pollutants (HAPS) include pollutants that are known or suspected to cause cancer or result in other serious health effects such as reproductive effects or birth defects. These include both metals and organic compounds. The inorganic pollutants of greatest environmental concern are metals such as arsenic, boron, cadmium, mercury, molybdenum and selenium; and for this project other TACs of concern are the reduced sulfur compounds formed in the gasification process: H_2S, carbon disulfide (CS_2) and carbonyl sulfide (COS). Mercury is of particular concern for coal gasification systems. The proposed system includes an activated carbon control system to reduce mercury emissions both from the hydrogen-rich gas stream before it is combusted in the CTG/HRSG and for the coal dryer exhaust to remove mercury volatilized in the upstream coal-drying process. Organic pollutants of concern include compounds such as formaldehyde and other incomplete products of combustion. Emissions of these categories of pollutants are expected to be in line with emissions from combustion-based plants. Please see the Public Health Section for a more thorough discussion of the toxic air pollutants and their emissions estimates and public health effects.

Summary

In summary, staff recommends the background ambient air concentrations in **Air Quality Table 6** for use in the modeling and impacts analyses. The maximum criteria pollutant concentrations from the past three years of available data collected at the monitoring stations near the proposed project site, excluding exceptional events, are used to determine these recommended background values.

Air Quality Table 6
Staff Recommended Background Concentrations (μg/m^3)

Pollutant	Averaging Time	Recommended Background	Limiting Standard	Percent of Standard
NO_2	1 hour CAAQS	140	339	56%
	1 hour NAAQS	83.3	188	44%
	Annual	24.7	57	47%
PM10	24 hour	238	50	**476%**
	24 hour NAAQS	97	150	65%
	Annual	44.2	20	**221%**
PM2.5	24 hour	67	35	**191%**
	Annual	21.2	12	**177%**
CO	1 hour	4,025	23,000	18%
	8 hour	2,411	10,000	24%
SO_2	1 hour CAAQS	42	655	6%
	1 hour NAAQS	24	197	12%
	3 hour	26	1,300	2%
	24 hour	13	105	12%

Source: ARB 2013b, U.S. EPA 2013b, and Energy Commission Staff Analysis
Note: PM2.5 24-hour data shown in **Air Quality Table 5** are the 98th percentile values, 1-hour NAAQS NO_2 data is a three year average of the 98th percentile of maximum daily values for the past three years of data, and 1-hour NAAQS SO_2 are 99th percentile of maximum daily values.

Where possible, staff prefers that the recommended background concentrations come from nearby monitoring stations with site characteristics similar to the proposed site. For this project, staff determined that these are the Shafter-Walker Street monitoring station, providing the ozone and NO_2 background concentration data, the Bakersfield-5558 California Avenue station and the Bakersfield-Golden State Highway monitoring station providing PM10, PM2.5 and CO background concentration data and the Fresno-1st Street monitoring station providing background SO_2 concentration data.

The background concentrations for PM10 and PM2.5 are above the most restrictive existing ambient air quality standards and are identified in **Air Quality Table 6** by bold font in the percent of standard column, while the background concentrations for the other pollutants are all well below the most restrictive existing ambient air quality standards.

The pollutant modeling analysis was limited to the pollutants listed above in **Air Quality Table 6**; therefore, recommended background concentrations were not needed nor determined for the other criteria pollutants (ozone, lead, visibility, etc.).

PROJECT DESCRIPTION AND EMISSIONS

Hydrogen Energy California LLC (HECA), owned by SCS Energy California, LLC, has proposed to build an Integrated Gasification Combined Cycle (IGCC) polygeneration project (hereafter referred to as HECA or the project) in Kern County, California. The project involves the conversion of a feedstock via gasification to a synthetic gas used for both power production and the manufacturing of nitrogen-based fertilizer products at an integrated manufacturing complex. The proposed feedstock is a 75 percent coal and 25 percent petroleum coke (petcoke) fuel blend as measured by the thermal input to the gasifier on a higher heating value (HHV) basis. Carbon dioxide (CO_2) produced during this process would be captured and used by the manufacturing complex and for enhanced oil recovery (EOR) at a nearby oil production field.

The facility developer is proposing to gasify a 75 percent coal and 25 percent petcoke fuel blend to produce the syngas. The proposed coal is a western sub-bituminous coal from New Mexico. The coal would be transported to Kern County by rail. The coal would then be transported to the site either by a new railroad spur or by truck from Wasco. Under Transportation Alternative 1, a new five mile railroad spur would be constructed to connect the project site to the existing San Joaquin Valley Railroad Buttonwillow line. This rail spur would allow the rail transport of coal all the way to the project site, and would also allow products to be shipped by rail directly from the manufacturing complex at the project site. Under Transportation Alternative 2, trucks would be used to transport the coal 27 miles from an existing coal transloading facility in Wasco to the project site. Additionally, all products would be trucked from the site to various locations within and outside of the San Joaquin Valley. It is estimated that 4,580 short tons of coal would be used per day. Petroleum coke, also called “petcoke” is a byproduct of the oil refining process. Currently, petcoke produced from California refineries is generally exported overseas. The applicant anticipates the petcoke for the project would be supplied from refineries located in the Los Angeles or Santa Maria area. The petcoke would be transported to the site by truck. It is estimated that 1,140 short tons of petcoke would be used per day. Several coal mines and petroleum refineries have been identified as potential coal and petcoke feedstock suppliers.

The feedstock would be gasified and processed at the facility to produce a hydrogen-rich syngas. Gasification is a chemical conversion process to convert the solid feed stock to syngas. The applicant is proposing the use of an oxygen-blown, dry-feed gasification technology incorporating a two stage operation. The Mitsubishi Heavy Industries (MHI) gasification system selected for this project incorporates equipment that grinds and dries the feedstock prior to gasification. The syngas produced in the gasifier is further processed and cleaned to produce both CO_2 and a hydrogen-rich fuel used for power generation and ammonia synthesis at the manufacturing complex.

The manufacturing complex would produce 1 million tons per year of nitrogen-based fertilizer products such as urea and urea ammonium nitrate (UAN). Intermediate products that are produced to make these fertilizer products, but that will not be sold as products, include anhydrous ammonia and nitric acid. A pressure swing adsorption unit would purify the hydrogen-rich syngas produced in the gasification process. The high purity hydrogen stream and a nitrogen stream from the air separation unit would be the feedstocks for the ammonia synthesis unit. The ammonia would be used onsite to produce urea pastilles and UAN solution. Recovered CO_2 from the gasification process would be purified and combined with the ammonia for urea synthesis. The UAN solution would be produced from nitric acid, ammonium nitrate and urea.

The CO_2 recovered from the project would also be used by Occidental of Elk Hills, Inc. (OEHI) for enhanced oil recovery at the nearby Elk Hills Oil Field. The CO_2 would be compressed and delivered by pipeline to OEHI’s enhanced oil recovery (EOR) production facility. The CO_2 would be distributed to injection wells in patterns designed to optimize crude oil recovery. Recovered fluids would be pumped to the surface at nearby production wells and transported to the EOR processing facility. The recovered fluid would contain liquids (crude oil) and gases (natural gas and CO_2). The natural gas can include CO_2 from break through at the production well. The CO_2 would be separated from the natural gas and recompressed for reinjection into the underground oil reservoir. Each time CO_2 is injected, a percentage of the CO_2 remains trapped in the reservoir and is unrecoverable. This unrecoverable CO_2 would be permanently trapped underground over time via three trapping mechanisms: physical, residual and geochemical. The physical trapping mechanism is expected to eventually sequester all the CO_2 delivered by HECA and used in the EOR process. Please see the **Carbon Sequestration and Greenhouse Gas Emissions** section of the PSA/DEIS for a complete discussion of the carbon sequestration and CO_2 emissions impacts for HECA and the OEHI EOR component.

Staff requested the applicant to respond to a number of data requests regarding the construction and operations emission estimates and air dispersion modeling analysis. The applicant responded to these requests in a number of separate data response documents[2] by providing additional project description and revised emissions estimates. Staff has compiled the latest information from the AFC (HECA 2012e), and the air quality data responses in this Preliminary Staff Assessment/Draft Environmental Impact Statement (PSA/DEIS) section. Staff has reviewed the revised emission estimates and air dispersion modeling analysis[3] and finds them to be reasonable considering the level of emissions mitigation now stipulated to by the applicant.

EQUIPMENT DESCRIPTION

The project is evaluated by breaking it into separate sections: the power generating facility including the integrated manufacturing complex and EOR operations. The Energy Commission has jurisdiction over the power generation and manufacturing complex while other entities have jurisdiction over the EOR operations. However, EOR operations are evaluated in this document as part of the whole of the project. A separate EOR operations discussion, including the equipment description, will follow the power generating facility and integrated manufacturing complex discussion.

The power generation element includes an integrated gasification combined cycle facility (IGCC), which includes solids handling, gasification and gas treatment, power generation, manufacturing complex and auxiliary equipment.

For emission calculation purposes, the emission sources are summarized as follows:

Feedstock Delivery, Handling & Storage	• Feedstock handling System: Bulk material unloading (including fluxant), loading, belt conveying, belt transfer points, silo loading; controlled by various baghouses.

[2] This includes the following: AFC, ATC, and data response references: HECA 2012d, HECA 2012e, HECA 2012j, HECA 2012q, HECA 2012s, HECA 2012z, HECA 2012dd, HECA 2012ff, HECA 2012hh, HECA 2012pp, HECA 2013a, HECA 2013b, OXY 2013c and OXY 2013e. The latest updated emissions estimates are summarized for all HECA emissions sources in HECA 2013a and HECA 2013b. Staff also reviewed the data responses that were provided to address intervenor data requests.

[3] This includes a review of the emission source inputs, including the type of source (point, volume, area) and the variables used to describe each source (emissions, height, location, temperature, etc. as appropriate).

Gasification	• Feedstock Grinder & Dryer • Gasifier • Syngas Treatment Equipment • Gasification Flare • Sulfur Recovery Unit (SRU) Flare • Rectisol® Flare • Tail Gas Thermal Oxidizer • Process Cooling Tower • Air Separation Unit (ASU) Cooling Tower • Carbon Dioxide Vent
Power Block	• Combined Cycle Combustion Turbine (MHI 501GAC®) • Power Block Cooling Tower
Other Equipment	• Auxiliary Boiler
Emergency Equipment	• Emergency Diesel Generator 1, 2,922 brake horsepower (bhp) • Emergency Diesel Generator 2, 2,922 bhp • Emergency Diesel Firewater Pump, 565 bhp
Manufacturing Complex	• Ammonia synthesis (including ammonia heater) • Urea Unit • Urea Pastillation • Pastillation Handling • Nitric Acid Unit • Ammonium Nitrate Unit • Urea Ammonium Nitrate (UAN) Unit

Solids Handling

Feedstock Delivery, Handling and Storage

As noted above, there are two different alternatives for feedstock delivery, handling and storage. Under Transportation Alternative 1, coal is brought to the project site via rail. The coal is unloaded from the trains and conveyed to a storage barn through a rail unloading and transfer system. The transfer conveyor is fully enclosed and all related coal feedstock buildings are fully enclosed. Petcoke would be delivered to the site by truck. A truck unloading station would be used to unload the trucks and convey the petcoke to storage.

Under Transportation Alternative 2, coal would be brought to the site in the same manner as petcoke. The feedstocks would be delivered to the project site via bottom dump haul truck. The truck unloading station would receive the petcoke or coal and a transfer system would convey the feedstock to storage.

Both the coal and petcoke unloading stations consist of buildings that would be fully enclosed with roofing and siding. Dust suppression spray systems and dust collection systems would be used as needed to control dust from these operations.

The coal and petcoke would be stored in separate piles in an enclosed storage building. The feedstock piles would have a 30 day total storage capacity consisting of approximately 140,000 tons of coal and 35,000 tons of petcoke. The feedstock would be blended as 75 percent coal and 25 percent petcoke on a British Thermal Unit (BTU) heat input basis and then placed on a conveyor to transfer the material from the storage building to the gasification system for further processing. Feedstock fed to the gasifier would be consistently blended to this level. The transfer system would be fully enclosed.

Fluxant Delivery, Handling and Storage

The applicant has indicated that after additional testing of the coal and petcoke, a limestone fluxant would need to be added to the gasifier feedstock. The fluxant would be trucked to the facility using enclosed or covered trucks, then unloaded and stored in a silo located just north of the feedstock building. The particulate emissions from the fluxant unloading and storage silo would be controlled by a baghouse. A total of 59,000 tons per year of fluxant would be used.

Gasification

Feedstock Grinding and Drying

The MHI gasification system includes equipment used to grind and dry the feedstock prior to gasification. Blended feedstock, including the limestone fluxant, is stored in intermediate bins prior to transport to the dryer. The coal/petcoke dryer receives the blended feedstock, grinds and dries it before entering the gasifier. The heat source for the drying is a portion of the turbine exhaust gas. Emissions from the HRSG exhaust gas are controlled by the oxidation catalyst and the SCR prior to the diversion of the exhaust gas to the dryer. Emissions from the dryer are controlled by a baghouse and activated carbon is used to facilitate the removal of mercury.

Gasifier

The MHI oxygen-blown gasifier is a two stage design and the feed enters the gasifier at two separate points. In the first stage, the feedstock is fed to the gasifier with O_2. The high temperatures in this stage produce CO_2 and water vapor. The temperatures are high enough to melt the coal ash. The coal ash is quenched in a water bath to facilitate removal of the gasification solids, which are eventually transported offsite. The remaining feedstock is added to the second stage without additional O_2. At this stage the char created through the pyrolysis of the feedstock in the second stage produces CO, and the CO and water form hydrogen and CO_2. The syngas leaves the gasifier through a syngas cooler for further processing. A cyclone and filter remove char from the stream to recycle it in the gasifier. Steam produced in this process is directed to the HRSG to assist in power generation.

The gasifier unit is a source of fugitive emissions from piping components such as valves and connectors from the gasification stream. The fugitive emissions from the syngas stream are mainly CO and CO_2 but also include methane, hydrogen sulfide, carbonyl sulfide and ammonia.

Syngas Treatment Equipment

Syngas from the gasifier is further treated prior to the CO_2 removal and treated further before its use in the manufacturing facility and its use for electricity generation. After leaving the gasifier the syngas is treated in a scrubber to remove chlorides. The syngas then enters the sour shift unit (SSU) where a water-gas reaction is used to convert the CO and water to CO_2 and hydrogen. The catalyst used in this reaction also facilitates the hydrolysis of carbonyl sulfide to hydrogen sulfide. The gas is then cooled and sent to an ammonia wash column to remove ammonia from the syngas. The shifted, cooled ammonia free syngas is then sent to the mercury removal unit. The mercury removal unit is needed to remove trace amounts of mercury occasionally found in petcoke and typically contained in western sub-bituminous coal. Mercury is removed from the stream using activated carbon. After the mercury is removed the syngas is treated in the acid gas removal (AGR) unit. Acid gas is a term used to describe a gas containing significant quantities of acidic gasses such as H_2S and CO_2. The facility is proposing to use a Rectisol® unit that utilizes a methanol solvent to absorb the H_2S, other sulfur compounds and CO_2. The resulting hydrogen-rich fuel is then sent to the combustion gas turbine (CTG) or to the pressure swing adsorption unit for further purification. CO_2 is separated from the stream where it is compressed and transported to OEHI for oil recovery operations and the manufacturing facility. The gasification and syngas treatment processes utilize three flares to control emissions during startup or upset conditions.

The pressure swing adsorption (PSA) unit generates a high-purity hydrogen gas stream from a portion of the syngas from the AGR unit. This high purity gas is sent as a feedstock to the ammonia synthesis unit. The off-gas from the PSA unit is compressed and sent as duct burner fuel to the heat recovery steam generator (HRSG).

Gasification Flare

The gasifier would be equipped with a 4,000 MMBtu/hr emergency elevated flare with a 0.5 MMBtu/hr natural gas pilot flame. Flaring from the gasifier would only occur during startup and shutdown or upset conditions. The flare would be used to safely dispose of gasifier startup gases, syngas (also called unshifted and shifted gases[4]) and hydrogen-rich fuel. The proposed MHI gasifier design minimizes flaring events. The MHI gasifier is a 100 percent-capacity gasifier with an internal membrane wall which eliminates rotations and requires less maintenance. During startup and shutdown flaring events the maximum firing rate for the flare would range from 2,386 MMBtu/hr for the flaring of unshifted gas, to 2,413 MMBtu/hr for the flaring of shifted syngas and to 2,926 lbs/hr for the flaring of natural gas. The applicant is proposing two startup/shutdown events per year.

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[4] Shifted gas sent to the flare would contain large amounts of hydrogen and carbon dioxide but would still contain sulfur, as H_2S, and other impurities, such as low levels of mercury, not yet removed in the process. Unshifted gas sent to the flare would contain large amounts of carbon monoxide, carbon dioxide and hydrogen and would also contain sulfur compounds, as carbonyl sulfide (COS), and the other impurities contained in the shifted gas.

Sulfur Recovery Unit (SRU) Flare

The sulfur recovery unit (SRU) would be equipped with an 800 MMBtu/hr elevated flare with a 0.3 MMBtu/hr natural gas pilot flame. Flaring would only occur during startup and shutdown or upset conditions. The flare's function would be to safely dispose of acid-gas streams containing sulfur from the acid gas removal (AGR) unit, gasification unit, and sour water stripper unit during startup or during emergency or upset events. The acid gas would be first vented through an emergency caustic scrubber and knockout drum to remove sulfur compounds and entrained liquids and then vented to the flare for oxidation of the remaining acid gas. During startup and shutdown the flare would be operated at a firing rate of approximately 36 MMBtu/hr. The applicant is proposing 40 hours per year of flare venting for the SRU flare.

Rectisol® Flare

The Rectisol® unit would be equipped with a 5,500 MMBtu/hr elevated flare with a 0.3 MMBtu/hr natural gas pilot flame. Flaring would only occur during startup and shutdown or upset conditions. The flare would be used as an emergency flare to safely dispose of low temperature gas streams from the acid gas removal (AGR) unit and its associated refrigeration unit during startup, shutdown, and unplanned upsets or emergency events. These gases, which would be first vented through a knockout drum to remove any entrained liquids prior to introduction to the flare header, would be below the freezing point of water and would require segregation from the other flared gases. During startup and shutdown the flare would be operated at a firing rate of approximately 430 MMBtu/hr. The applicant is proposing 40 hours per year of flare venting for the Rectisol® flare.

SRU/Tail Gas Thermal Oxidizer

The facility would utilize a sulfur recovery system to recover sulfur from the processing facility and convert it to a usable sulfur byproduct. The sulfur recovery system would consist of a sulfur recovery unit (SRU) and a tail gas unit (TGU). Acid gas from the AGR unit would be sent to a SRU where H_2S is first oxidized to SO_2 followed by an SO_2 conversion to elemental sulfur in a reaction furnace. SRU effluent gases would then be sent to a tail gas unit (TGU) to convert the remaining sulfur compounds in the gas back to H_2S. The tail gas unit would be equipped with a natural gas fired thermal oxidizer rated at 96 MMBtu/hr to combust 16 MMBtu/hr of natural gas from the assist burner and 80 MMBtu/hr from the waste gas burner. The SRU tail gas thermal oxidizer would be operated to oxidize H_2S and other vent gas components that would be generated during startup, shutdown, and other miscellaneous gasification unit streams (tank and equipment vents) during normal operation to prevent nuisance odors during operation. The recovered sulfur would be in the form of liquid elemental sulfur that would be trucked offsite as a secondary product. The overall sulfur recovery is estimated to range from 99.8 to 99.9+ percent.

The emissions calculated from the unit were originally based on a 13 MMBtu/hr natural gas assist burner. However due to recent changes in project design, the natural gas burner capacity was increased to 16 MMBtu/hr. However, the applicant intends to limit emissions to the level proposed in the application. The SRU unit also would have fugitive emissions from the piping components from various VOC and CO laden streams, including the sulfur and the tail gas treatment unit processes.

Process Cooling Tower

The process block cooling tower would be used for heat rejection from the CO_2 compressor and AGR refrigeration unit. The process block cooling tower circulation rate would be approximately 163,000 gpm of water and it would operate 8,322 hours annually. The cooling tower would operate with a maximum total dissolved solids (TDS) concentration of 9,000 ppmw[5] and the cooling tower's particulate emissions would be controlled with a high efficiency drift eliminator designed to reduce the drift to less than 0.0005 percent of circulation.

Air Separation Unit (ASU) Cooling Tower

The ASU cooling tower would be in the ASU unit and reject waste heat from the ASU. The ASU, including the ASU cooling tower, would be designed, built, owned, and operated by another party. However, for permitting purposes it is considered part of the HECA facility. The ASU cooling tower circulation rate would be approximately 45,000 gpm of water and it would operate up to 8,322 hours annually. The cooling tower would operate with a maximum total dissolved solids (TDS) concentration of 2,000 ppmw[6] and the cooling tower's particulate emissions would be controlled with a high efficiency drift eliminator designed to reduce the drift to less than 0.0005 percent of circulation.

Carbon Dioxide Vent

The carbon dioxide vent would be used to release the produced CO_2 vent stream, which would contain small amounts of CO, VOC, and H_2S when the exhaust compression, pipeline, or injection systems are unavailable. The OEHI component as currently envisioned does not include a back-up enhanced oil recovery CO_2 injection zone. However the CO_2 vent would be limited to 504 hours per year, which is the worst case venting assumption during early operation (first two years). CO_2 venting is expected to occur no more than 120 hours per year during mature operations. Carbon dioxide emissions estimates in the **Carbon Sequestration and Greenhouse Gas Emissions** PSA/DEIS section include these emissions.

Power Block

Power Block CTG/HRSG Unit

The combined cycle power block would generate approximately 431 MW of gross power and would provide low-carbon baseload electricity primarily using hydrogen-rich fuel generated from the project's gasification unit. The power generation equipment is similar to conventional natural gas power plants; however, there is substantial heat integration with the gasification process where heat is recovered for useful energy in the

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[5] The TDS levels could range from 3,000 to 9,000 ppmw for the project's cooling towers, depending on the raw water quality and operating cycles of concentration for each cooling tower. For permitting purposes the maximum level of 9,000 ppmw has been assumed.

[6] The applicant has indicated that this cooling tower requires a lower TDS level than the power block and process cooling towers; that is why it is assumed to have a TDS level of 2,000 ppmw versus the 9,000 ppmw TDS levels assumed for the other two cooling towers.

form of additional power generation. The combined cycle block would include a single-shaft MHI 501GAC® G-class, air-cooled combustion turbine/steam turbine generator configured to burn hydrogen-rich fuel. The block also includes a HRSG and water cooled surface condenser. The exhaust gas from the turbine as well as supplemental hydrogen-rich fuel and PSA off-gas for duct-firing would be sent to the HRSG to generate additional electricity.

The combustion equipment would also be equipped with separate fuel nozzles for natural gas. The facility would be permitted for limited natural gas operation during startup, shutdown and equipment outages. The combustion turbine generator (CTG) would use natural gas during periods of unplanned equipment outages but not during normal operation. When operating on natural gas, water would be injected to control NOx emissions. During startup operations the CTG/heat recovery steam generator (HRSG) would be fired on natural gas and would transition to hydrogen-rich fuel two and a half hours into the startup sequence. A startup sequence is estimated to require 4.5 hours and the shutdown sequence is estimated to take 9 hours. A total of two startup/shutdown sequences are expected to be needed per year. The maximum expected operating schedule for the CTG/HRSG is provided in **Air Quality Table 7**. These hours reflect early operations when the facility owners are learning how to use the facility efficiently. These conditions are used to establish permit operating limits. More mature operations would require less use of natural gas, and fewer startup/shutdown cycles and less CO_2 venting (not shown in the table).

Air Quality Table 7
Maximum Annual CTG/HRSG Operating Schedule (Early Operations)

Operating Conditions	Early Operations (Maximum Permitted)
Total Hours of Operation	8,363
Hydrogen-Rich Fuel Operation	8,000
Natural Gas	336
Startup/Shutdown	27

Source: HECA 2013a, HECA 2013b

For permitting purposes the duct burner operation has been assumed to operate 100 percent of the time the turbine is operating, except during startup and shutdown periods. The applicant assumes that during early operations, natural gas firing would occur up to two weeks per year, or 336 hours per year for unplanned equipment outages.

The HRSG would be equipped with emission control technology to reduce stack emissions. The HRSG would include an SCR system used to meet BACT requirements for NOx. The SCR system would use ammonia injected upstream of the SCR catalyst. The SCR catalyst would be used to convert NOx and ammonia into nitrogen and water. An oxidation catalyst would be used upstream of the SCR ammonia injection location to oxidize CO and VOC to reduce their emissions. A portion of the treated exhaust gas would be sent to the gasification unit to dry the feedstock. The HRSG stack would be equipped with a continuous emissions monitoring system (CEMS) to verify compliance with applicable emission limits. The CEMS would be used to monitor NOx, CO and O_2 and would be certified to comply with the applicable SJVAPCD and U.S. EPA standards.

Power Block Cooling Tower

The largest heat rejection load would be the steam turbine surface condenser in the power block. The power block cooling tower would be used to facilitate removal of the waste heat from the steam power cycle portion of the combined cycle CTG/HRSG. Approximately 95,500 gallons per minute (gpm) of water would be circulated in the power block cooling tower, which would operate 8,668 hours annually. The cooling tower would operate with a maximum total dissolved solids (TDS) concentration of 9,000 parts per million by weight (ppmw)[7] and the cooling tower's particulate emissions would be controlled with a high efficiency drift eliminator designed to reduce the drift to less than 0.0005 percent of circulation.

Other Equipment

Auxiliary Boiler

The auxiliary boiler, fired exclusively on natural gas, would be used to provide steam to facilitate CTG startup and for other miscellaneous purposes when steam from the gasification block or HRSG is not available. During typical operation the auxiliary boiler would be in either warm standby or cold standby. The proposed boiler was originally rated at 213 MMBtu/hr when operated on natural gas. Due to recent changes in project design, the currently proposed boiler would have a maximum heat input of 230 MMBtu/hr; however, HECA intends to limit the boiler operation to 213 MMBtu/hr equivalent to keep emissions at the same level as proposed in the application. Annual emissions from the auxiliary boiler were calculated based on full-time operation at a 23 percent annual capacity factor[8]. The auxiliary boiler would be equipped with an ultra-low NOx burner and selective catalytic reduction to further reduce NOx emissions. Emergency Equipment.

Emergency Diesel Generator

The proposed project includes two diesel-fired emergency internal combustion engines powering emergency generators. The generators would be used to supply emergency service power to critical components as needed during an electric grid power outage. The proposed engines would be Tier 4 certified and rated at 2,922 bhp each. Other than emergency operation, the engines would be operated up to 50 hours per year each for maintenance and readiness testing purposes.

Emergency Firewater Pump

The proposed project includes a Tier 4, 556 bhp diesel-fueled emergency internal combustion engine powering a firewater pump that would only be used in an emergency to put out fires, maintenance and readiness testing. Other than emergency operation, the engine could be operated up to 100 hours per year for maintenance and readiness testing purposes.

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[7] The TDS levels could range from 3,000 to 9,000 ppmw for the project's cooling towers, depending on the raw water quality and operating cycles of concentration for each cooling tower. For permitting purposes, the maximum level of 9,000 ppmw has been assumed.

[8] Originally the calculations used a 25 percent annual capacity factor for the 213 MMBtu/hr rated boiler, however 23 percent is the equivalent annual capacity factor for the higher 230 MMBtu/hr rated boiler.

Manufacturing Complex

Ammonia Synthesis

The proposed manufacturing complex includes an ammonia synthesis unit. The ammonia synthesis unit manufactures ammonia for urea pastilles and UAN solution production. After consideration, the applicant has determined that the ammonia would not be shipped as a separate product; however, the transportation emissions estimates still include ammonia transportation. The ammonia synthesis unit uses nitrogen from the ASU and high purity hydrogen from the PSA to convert the nitrogen and hydrogen to ammonia. This exothermic conversion occurs over an iron-based catalyst. The effluent is used to generate steam in the waste heat boiler. Cold liquid ammonia is stored in two vertical steel tanks housed in a second vessel and equipped with a vapor recovery system to prevent losses.

A natural gas fired startup heater rated at 55 MMBtu/hr would be used to raise the catalyst bed temperature during plant commissioning and startup. The operation of the unit would be equivalent to 140 hours per year of full capacity operation.

A leak detection and repair (LDAR) program has been proposed by the applicant to limit fugitive emission from the NH_3 streams.

Urea Unit

A proposed urea unit would be used to produce a concentrated urea solution. The urea unit would combine a purified stream of CO_2 recovered in the AGR with ammonia from the ammonia synthesis unit to produce the concentrated urea solution. This solution would be used as feed to the UAN solution and urea pastilles.

The off-gas from the urea synthesis would consist of CO_2, nitrogen, water feed, process air, and unreacted ammonia. The off-gases would be scrubbed to remove the ammonia from the stream. Ammonia emissions from the urea absorbers are estimated based on plant capacity. A LDAR program has been proposed by the applicant to limit fugitive emission from the NH_3 and CO_2 streams.

Urea Pastillation Unit and Pastille Handling System

The concentrated urea would be converted to high-quality pastilles. The process would occur in an enclosed area with a hood and baghouse to control the urea dust. The urea pastilles would then be conveyed to urea storage and a rail/truck load out facility. All conveyors and the handling system building would be fully enclosed and equipped with dust collection systems. The dust collectors from the material handling system and urea pastillation unit would be designed to limit PM emissions (PM10 and PM2.5) to 0.001 grains per dry standard cubic feet.

Nitric Acid Unit

Nitric acid production is an intermediate step in urea ammonium nitrate (UAN) production. Ammonia from the ammonia synthesis unit would be oxidized by high temperature air over a platinum-based catalyst. Nitric oxide formed during the ammonia oxidation would also be oxidized in a non-catalytic reaction with O_2 to form nitrogen dioxide. The nitrogen dioxide is cooled and sent into an absorption tower with water where nitric acid is formed. Tail gas from the absorber column would be cleaned prior to venting by catalytic decomposition and reduction of N_2O and NOx. Primary and secondary reduction of N_2O would occur without a catalyst. Tertiary reduction would occur with a catalyst under high temperatures to reduce 95 percent of the remaining N_2O. NOx emissions would be reduced using SCR with injected ammonia as a reducing agent. NOx emissions would be limited to 0.2 lb/ton of nitric acid (approximately 15 ppmv). To adequately control the NO_2 emissions, sufficient ammonia must be injected into the SCR system. Based on information from the manufacturer, ammonia emissions would be limited to 10 ppm or 1.0 lbs/hour.

Ammonium Nitrate Unit

Ammonium nitrate production is another intermediate step in UAN production. Ammonia and nitric acid would be combined to produce an ammonium nitrate solution. The vent stream would contain water vapor and residual ammonium nitrate solution that would be routed to a water scrubbing system to reduce particulate emissions. The vent scrubber would condense the vapor into a condensate which would absorb the mist droplets. Emissions of PM from the condensing vent scrubbing system and the scrubber vent particulate emissions would be limited to less than 0.2 lb per hr, assumed to all be PM2.5 or smaller.

Urea Ammonium Nitrate Unit

The ammonium nitrate solution and the urea solution are metered, mixed and cooled in the urea ammonium nitrate (UAN) unit. The final product may contain water depending on final product specifications. The UAN solution would be stored in tanks and then loaded into railcars or trucks for shipment. An LDAR program has been proposed by the applicant to limit fugitive emission from the NH_3, CO_2 and HNO_3 streams.

CONSTRUCTION

Emission sources during construction of HECA would include on-site sources, linear construction sources, and off-site sources. On-site emission sources would include combustion and fugitive emissions from construction equipment and activity, delivery trucks entering the site and commuter vehicles. Construction activities would include clearing and grubbing of vegetation, grading, hauling and payout of equipment, hauling materials and supplies, and project facility construction and testing. Linear sources would include the construction equipment required for linear construction, specifically construction activities associated with the water supply pipeline, carbon dioxide pipeline, natural gas supply, electrical transmission line, and potential rail spur. Construction of the on-site rail spur and rail unloading facility would only be required under Transportation Alternative 1. Off-site emissions sources would include combustion and fugitive emissions from delivery trucks and worker commuter vehicles while traveling off-site. The trip distances for the off-site sources were all assumed to be within Kern County.

The construction/commissioning period would last approximately 49 months. This includes 42 months of site preparation and construction and up to 18 months of commissioning and startup. The commissioning and startup period would partially overlap with the construction period. During the construction and commissioning period, emissions would vary depending on the specific scheduled activities and conditions. The applicant provided a detailed schedule including the quantity of equipment needed and expected usage. This list served as the basis for estimating emissions and determining periods of maximum short-term construction emissions.

Onsite and offsite construction particulate emission estimates include emissions from both fuel combustion and fugitive sources. Fugitive particulate emissions can result from areas that are disturbed due to grading, excavating and construction of project structures. Various areas within the project site would be disturbed at different times during the 42 month construction period. Additionally, paved and unpaved road travel creates fugitive dust emissions. Combustion emissions result from exhaust sources, including diesel-fired construction equipment used for site preparation and building/structure construction, water trucks used to control dust emissions, welders, heaters, portable generators, air compressors, pumps, diesel trucks for deliveries and vehicles used by workers to commute to and from the construction site. Construction activities were assumed to occur approximately 22 days per month (Monday-Friday) with a single shift each day.

The applicant's emissions estimates from the construction vehicles incorporated several conservative (over predictive) assumptions. Emissions from the on-road vehicles are based on 2010 emission factors using the ARB EMFAC2007 model and the off-road vehicle emissions are based on the ARB OFFROAD2007 model. These models were updated by ARB in 2011. The older EMFAC2007 and OFFROAD2007 models are used in the emission estimates because the U.S.EPA has not yet approved the use of the new ARB models for Transportation Conformity analyses. While this project requires a General Conformity analysis and not a Transportation Conformity analysis, to be conservative the applicant decided to use the U.S.EPA-approved ARB emission factor models. The EMFAC2007 and EMFAC2011 model emissions factors are very similar for the same vehicles and model years, but there are some minor differences including revisions to the tire wear and brake wear emission assumptions. The major difference in the OFFROAD2007 and OFFROAD2011 model's emissions factors is the large reduction in the assumed engine capacity factor. The OFFROAD2011 model has reduced the assumed capacity factor by one-third resulting in a major difference in the calculated emission factor. Another conservative assumption for both the on-road and off-road equipment emissions estimates is the use of a 2010 baseline to develop the emissions factors rather than the years 2013 through 2016 when construction is expected to occur if the project is licensed. This assumption does not reflect model year improvements that are driven by federal and state regulation (i.e. nonroad equipment emissions standards) that cause an ongoing reduction of emissions from diesel-fired equipment. Therefore, using these older models and input assumptions would result in conservative on-road vehicle emissions estimates and very conservative off-road equipment emissions estimates.

The applicant determined that the short-term maximum construction emissions occur during the third month of construction for PM10 and PM2.5, when the fugitive dust generating mass grading activities are being conducted and before the internal site road is constructed, and during the 24th month of construction for other criteria pollutant emissions when there are extensive structure construction activities under way. The maximum annual emissions, which are based on the peak 12 consecutive months of emissions during the construction period, occur during months 1 through 12 for PM10 and PM2.5 emissions and during months 20 through 31 for the other criteria pollutant emissions. The Applicant's estimates for the highest emissions during construction are provided in **Air Quality Table 8** (daily emissions) and **Air Quality Table 9** (annual emissions).

Air Quality Table 8
Maximum Daily Construction Emissions

Activity (lbs/day)	NOx	CO	SOx	VOC	PM10	PM2.5
On-Site Combustion Emissions						
On-Road Equipment	131.41	63.46	0.13	23.48	4.72	4.25
Off-road Equipment	253.50	168.18	0.32	52.74	13.02	11.98
Worker Vehicles	0.39	4.82	0.01	0.37	0.00	0.00
Delivery Trucks	5.14	2.21	0.00	1.36	1.82	1.65
On-Site Fugitive Emissions						
On-road Equipment					9.10	0.91
Off-road Equipment					1.35	0.13
Worker Vehicles					1.09	0.11
Delivery Trucks					89.19	9.08
Construction Activity					220.3	62.9
Subtotal, On-Site Emissions	390.44	238.67	0.46	77.95	340.59	91.01
Off-Site Construction Emissions						
Off-Site Combustion Emissions						
Worker Vehicles	44.24	369.57	0.44	11.37	0.16	0.08
Delivery Trucks	78.16	15.40	0.07	3.40	11.13	9.54
Off-Site Paved Road Fugitive Dust Emissions						
Worker Vehicles					0.35	0.09
Delivery Trucks					14.00	3.44
Subtotal, Off-Site Emissions	122.41	384.97	0.51	14.77	25.65	13.15
Total Max. Daily Emissions (lbs/day)	**512.84**	**623.64**	**0.97**	**92.72**	**366.23**	**104.16**

Source: HECA 2013a, HECA 2013b
Notes:
a. Worst-case onsite daily emissions would occur during Month 3 of construction for PM10 and PM2.5 and Month 24 of construction for the other pollutants.

Air Quality Table 9
Maximum Annual Construction Emissions

Activity (tons/year)	NOx	CO	SOx	VOC	PM10	PM2.5
On-Site Combustion Emissions						
On-Road Equipment	17.22	8.32	0.02	3.07	0.78	0.70
Off-road Equipment	30.15	20.31	0.04	6.33	1.48	1.37
Worker Vehicles	0.05	0.68	0.00	0.05	0.00	0.00
Delivery Trucks	0.68	0.29	0.00	0.18	0.16	0.14
Linear Combustion Emissions	3.90	2.43	0.00	0.76	0.14	0.13
Subtotal of Project Emissions	52.00	32.03	0.06	10.39	2.56	2.34
On-Site Fugitive Emissions						
On-road Equipment					1.10	0.11
Off-road Equipment					0.15	0.01
Worker Vehicles					0.30	0.03
Delivery Trucks					6.69	0.68
Construction Activity					18.90	5.48
Linear Fugitive Emissions					0.06	0.01
Subtotal of Fugitive Emissions					27.20	6.32
Subtotal of On-site Emissions (no linears)	48.10	29.60	0.06	9.63	29.56	8.52
Subtotal, On-Site Emissions	52.00	32.03	0.06	10.39	29.76	8.66
Off-Site Construction Emissions						
Off-Site Combustion Emissions						
Worker Vehicles	6.25	52.22	0.06	1.61	0.07	0.03
Delivery Trucks	10.32	2.03	0.01	0.45	1.01	0.86
Subtotal of Off-Site Combustion Emissions	16.57	54.25	0.07	2.06	1.08	0.89
Off-Site Paved Road Fugitive Dust Emissions						
Worker Vehicles					0.14	0.04
Delivery Trucks					1.28	0.31
Subtotal of Off-Site Fugitive Emissions					1.42	0.35
Subtotal, Off-Site Emissions	16.57	54.25	0.07	2.06	2.50	1.24
Total Maximum Annual Emissions (tons/year)	68.57	86.28	0.13	12.45	32.26	9.90

Source: HECA 2013a, HECA 2013b
Notes:
a. Worst-case onsite daily emissions would occur during Months 1-12 of construction for PM10 and PM2.5 and Months 20-31 of construction for the other pollutants.

INITIAL COMMISSIONING

The initial commissioning of a power plant refers to the time between the completion of construction and the reliable production of electricity for sale on the market. For most power plants, normal operating emission limits usually do not apply during the initial commissioning activities due to the need to test individual components during commissioning, often before emission controls are operational.

The commissioning and initial startup is currently scheduled to require 18 months to complete. The commissioning for the project would require four distinct phases which are described as follows:

1. Power block commissioning on natural gas

2. Power block commissioning on hydrogen-rich fuel

3. Gasification block and balance of plant (BOP)

4. Manufacturing Complex

Commercial operation would start when the commissioning and startup activities are completed and the licensor/contractor guarantees and milestones have been achieved.

The commissioning activities would occur in several phases. They would begin with the utility and support systems, which includes electric power, water treating, natural gas supply, auxiliary boiler, cooling tower, and safety systems.

The fertilizer manufacturing process units would be commissioned in the general order of the manufacturing process, with the feed producing units commissioned before the product producing units. This commissioning process includes several plants and support systems with an estimated 3,388 total hours of commissioning operations.

The power block would be commissioned before commissioning the gasification block to ensure the reliability of the power block to supply substantial amounts of electrical power to be consumed by the gasification block. The power block would be commissioned only on natural gas during this period. This commissioning phase is estimated to require 1,129 hours of commissioning operations, during which emissions would be partially abated since the commissioning of the emissions control devices, including the SCR unit, is part of this commissioning phase. This phase of commissioning would be followed by gasification block commissioning.

The gasification, Rectisol®, and sulfur recovery unit (SRU) flares would be tested with natural gas and nitrogen. The tail gas thermal oxidizer would also be commissioned on natural gas. Included in the gasification block initial commission emissions are the balance of plant (BOP) operations not otherwise included in the CTG/HRSG initial commissioning emission estimate.

The last commissioning phase is to commission the power block on hydrogen-rich fuel. The hydrogen-rich fuel and nitrogen blending systems would be commissioned, and the CTG combustors would be tuned for different fuel types. Unlike during the natural gas commissioning phase, the emission control devices would be operating at all times when operating within their normal operating temperature range. The CTG would be performance-tested on hydrogen-rich fuel at the end of this commissioning phase.

Emissions estimates for each commissioning phase are shown in **Air Quality Table 10**.

Air Quality Table 10
Summary of Commissioning Emissions

Phase	NOx	CO	VOC	SOx	PM10/PM2.5
Max Hourly Commissioning Event Emissions (lb/hr)[a]					
CTG/HRSG on Natural Gas	391.20	2,270.00	65.00	4.80	15.00
CTG/HRSG on Hydrogen-Rich Fuel	99.04	1,622.60	35.12	5.13	15.00
Gasification Block and BOP	140.00	4,000.00	5.50	11.03	1.85
Manufacturing Complex	81.20	1.52	0.16	0.08	0.32
Total Commissioning Emissions (tons)[a]					
CTG/HRSG on Natural Gas	61.03	199.35	4.75	2.06	8.32
CTG/HRSG on Hydrogen-Rich Fuel	20.83	132.79	4.41	1.83	8.51
Gasification Block and BOP	52.53	614.40	2.73	6.04	12.40
Manufacturing Complex	4.00	0.18	0.03	0.01	0.24
Total Commissioning Emissions	**138.39**	**946.72**	**11.92**	**9.94**	**29.47**

Source: HECA 2012e
Notes:
[a] – The maximum hourly emissions for the gasification block and BOP are for the largest single commissioning event and do not include concurrent commissioning activities.
[b] - The annual cooling tower emissions associated with the CTG/HRSG commission are shown with the Gasification Block and BOP emissions.

OPERATIONAL PHASE

Project Operating Emissions

The operational emissions from the project include both the power generating facility and integrated manufacturing complex. The most significant emission source would be emissions from combustion of the hydrogen-rich syngas in the combined cycle power block. Other significant sources of emissions would be the combined emissions generated from on-site and off-site mobile sources, the coal dryer, tail gas thermal oxidizer and nitric acid plant. Minor emission sources would include the auxiliary boiler, flares, cooling towers, two emergency diesel-fired engines powering emergency generators, emergency firewater pump engine, CO_2 vent and miscellaneous operations for the manufacturing complex. Emissions from the project would include normal operating conditions as well as emissions from startup and shutdown events that are considered normal operation for the equipment. One to two plant startup/shutdown events are anticipated annually to perform major maintenance. Emissions from startup and shutdown operations are often higher than normal operating conditions as many control systems are optimized to parameters associated with normal operations and not startup/shutdown.

CTG HRSG Emissions

The emissions from the proposed project's CTG/HRSG include both startup and shutdown events and normal operations. The differences in the emission rates are due in part to the chemical and physical differences of the fuel types, and also because the combustor is tuned to operate on a hydrogen-rich fuel/nitrogen mixture and therefore it does not meet the same emissions guarantees when operating on natural gas. The CTG/HRSG would be fired on natural gas during the first two and a half hours of a startup event and last five hours of a shutdown event. **Air Quality Table 11** presents the total startup and shutdown emissions per event.

Air Quality Table 11
Summary of HRSG/Coal Drying Startup and Shutdown Emissions, lbs/event

Pollutant	NOx	CO	VOC	SOx	PM10/PM2.5
Startup (4.5 hrs)	429.9	3,702.7	73.0	12.2	63.7
Shutdown (9 hrs)	804.6	8,482.8	196.7	23.4	131.4

Source: HECA 2013a, HECA 2013b

The applicant's estimated average normal hourly CTG/HRSG and coal dryer operating emissions for each fuel type are presented in **Air Quality Table 12**.

Air Quality Table 12
Summary of Normal Hourly HRSG/Coal Dryer Operating Emissions, lbs/hr

Pollutant	NOx	CO	VOC	SOx	PM10/PM2.5
Hydrogen-Rich Fuel					
HRSG	25.0	18.3	3.5	4.1	12.9
Coal Dryer	4.4	3.2	0.6	0.9	1.4
Combined Maximum	29.4	21.5	4.1	5.0	14.3
Natural Gas	34.1	26.0	5.9	4.7	15.0

Source: HECA 2013a, HECA 2013b

Maximum short-term operational emissions from the CTG/HRSG and coal dryer were determined from a comparative evaluation of potential emissions corresponding to normal operating conditions, and CTG startup/shutdown conditions. **Air Quality Table 13** presents worst case hourly emissions regardless of fuel type. The maximum hourly CTG/HRSG and coal dryer emissions generally occur during startup or shutdown, but the maximum SOx and PM10 emissions occur during normal operations for hydrogen-rich fuel and natural gas fuel operations, respectively.

Air Quality Table 13
Summary of Worst Case Hourly CTG/HRSG Emissions, lbs/hr

Pollutant	NOx	CO	VOC	SOx	PM10/PM2.5
HRSG	122.0	2270.0	64.8	4.7	15.0
Coal Dryer	15.1	147.4	1.9	0.9	1.5
Combined Maximum [a]	122.3	2270.0	64.8	5.0	15.0

Source: HECA 2013a, HECA 2013b
Note: a – This summary includes startup and shutdown and both fuels. The worst case hourly HRSG and coal dryer emissions do not always happen concurrently. For example the worst case PM10/PM2.5 emissions for the coal dryer occur during maximum normal operation, while the worst case PM10/PM2.5 emission from the HRSG and the total for the HRSG and coal dryer combined occur during the last seven hours of a shutdown.

Transportation Emissions

Mobile emissions from the project would occur from several different types of sources, including; trucks for the transport of petcoke and products, trains for the transport of coal and products, dedicated site trucks for onsite maintenance, and employee vehicles. Transportation Alternative 1 assumes that a rail spur would be built to the site and that the trains would be unloaded at the project site, while Transportation Alternative 2 assumes that the trains would be unloaded in Wasco and the coal would be trucked from Wasco to the project site. The applicant completed emissions estimates for both transportation alternatives. The annual mobile source emissions estimates for the emissions that occur within the SJVAB under each option are presented in **Air Quality Table 14**.

Air Quality Table 14
Summary of Annual Mobile Source Emissions (SJVAB), tons/yr

Pollutant	NOx	CO	VOC	SOx	PM10	PM2.5
Transportation Alternative 1						
On-site trucks	0.99	0.63	0.16	0.01	0.15	0.05
On-site trains	2.38	0.85	0.12	0.06	0.04	0.04
Off-site workers commuting	0.48	4.17	0.13	0.01	1.05	0.28
Off-site trucks	8.71	5.29	0.74	0.06	2.39	0.72
Off-site trains	23.85	6.17	0.66	0.44	0.39	0.37
Total	**36.41**	**17.11**	**1.81**	**0.58**	**4.02**	**1.46**
Transportation Alternative 2						
On-site trucks	2.76	1.42	0.41	0.01	0.28	0.09
Off-site workers commuting	0.48	4.17	0.13	0.01	1.05	0.28
Off-site trucks	23.42	14.22	1.98	0.17	6.43	1.94
Off-site trains	13.48	3.49	0.37	0.25	0.22	0.21
Total	**40.14**	**23.30**	**2.89**	**0.44**	**7.98**	**2.52**

Source: HECA 2013a, HECA 2013b

A feedstock and product transportation emission estimate was also performed by the applicant for the other air quality jurisdictions within California and the other states affected by the coal feedstock and product transportation emissions. It is assumed that the coal would be transported by rail from a mine in northwestern New Mexico and that petcoke would be shipped by truck from Los Angeles area refineries. The project's products, including sulfur, coal ash, and the fertilizer manufacturing plant products would be shipped by truck or rail to various locations within and outside of California depending on the transportation alternative. The estimated emissions for each of the two transportation alternatives are presented in the **Air Quality Table 15**.

Project Total Emissions

Air Quality Table 16 presents worst case daily emissions for each of the stationary sources within the facility. The worst case daily emissions presented in the table include all the equipment from the entire facility. These worst-case daily emissions do not directly correlate to worst-case operating conditions because the worst-case conditions from the individual sources do not all occur concurrently. Therefore, this table indicates how many hours a day each of these sources operates when emitting their peak daily emissions and the summation of these individual worst-case conditions would not be representative of the worst cast operating scenarios.

The following assumptions are used to derive the worst case daily emissions.

- The CTG/HRSG emissions estimate assumes a worst case for each pollutant which is either normal operation with natural gas (SOx and PM10/PM2.5), or a 9 hour shutdown preceded by 15 hours of normal operation with natural gas (NOx, CO, and VOC).

Air Quality Table 15 [a]
Feedstock and Product Transportation Outside of SJVAB, ton/year

	NOx	CO	VOC	SOx	PM10	PM2.5
Transportation Alternative 1						
Los Angeles-South Coast Air Basin						
Off-site trucks	6.82	4.14	0.58	0.05	1.87	0.56
Kern County						
Off-site trains	13.98	3.62	0.39	0.26	0.23	0.22
San Bernardino County						
Off-site trains	40.47	10.47	1.12	0.74	0.65	0.63
Los Angeles-San Bernardino Counties						
Off-site trains	23.11	5.98	0.64	0.42	0.37	0.36
State of Arizona						
Off-site trains	70.1	18.13	1.94	1.28	1.13	1.1
Sacramento Metro						
Off-site trains	1.27	0.33	0.04	0.02	0.02	0.02
Yuba City-Marysville						
Off-site trains	0.8	0.21	0.02	0.01	0.01	0.01
Chico, CA						
Off-site trains	0.8	0.21	0.02	0.01	0.01	0.01
Other Area in CA and State of Oregon/Washington						
Off-site trains	2.56	0.66	0.07	0.05	0.04	0.04
State of New Mexico						
Off-site trains	19.55	5.05	0.54	0.36	0.32	0.31
Total	**179.46**	**48.80**	**5.36**	**3.20**	**4.65**	**3.26**
Transportation Alternative 2						
Los Angeles-South Coast Air Basin						
Off-site trucks	6.96	4.23	0.59	0.05	1.91	0.58
Kern County						
Off-site trains	11.94	3.09	0.33	0.22	0.19	0.19
San Bernardino County						
Off-site trains	39.19	10.13	1.08	0.72	0.63	0.61
Los Angeles-San Bernardino Counties						
Off-site trains	23.11	5.98	0.64	0.42	0.37	0.36
State of Arizona						
Off-site trains	70.1	18.13	1.94	1.28	1.13	1.10
State of New Mexico						
Off-site trains	19.55	5.05	0.54	0.36	0.32	0.31
Total	**170.85**	**46.61**	**5.12**	**3.05**	**4.55**	**3.15**

Source: HECA 2013a, HECA 2013b
Note: [a] – The transportation emissions estimates include ammonia shipping which has since been removed from the project description and do not include the fluxant shipping which was a late addition to the project description. The emissions from fluxant shipping would be lower than the emissions from ammonia shipping due to the higher quantity of ammonia that was assumed to be shipped from the site. Therefore, the emissions presented above are slightly conservative for the current project description.

- The coal dryer emissions estimate assumes a worst case for each pollutant which is either normal operation at the worst-case ambient condition (SOx and PM10/ PM2.5), or a 4 hour startup followed by 20 hours of normal operation at the worst-case ambient condition (NOx, CO, and VOC).
- The three cooling towers, the auxiliary boiler, the CO_2 vent, nitric acid unit, urea pastillation unit, ammonium nitrate unit, and ammonia startup heater are assumed to operate 24 hours/day.

- The tail gas thermal oxidizer is assumed to operate in startup mode for 24 hours.
- The SRU and Rectisol® flares are conservatively assumed to operate with pilot and vented gas 24 hours.
- The Gasification Flare is assumed to operate through one 10 hour startup sequence with the pilot on for 24 hours.
- Each emergency generator is assumed to operate 1 hour per day.
- The fire pump is assumed to operate 2 hours per day.
- Feedstock, urea, and gasification solids materials handling occurs 6 to 24 hours per day depending on the specific material handling source (there are 18 separate sources with emissions calculations). The emissions estimate provided is for the solids material handling associated with Transportation Alternative 1, which forms the permitted emissions basis for the project that Alternative 2 would also have to achieve.
- Fugitive emissions are assumed to occur 24 hours/day.

Air Quality Table 16
Summary of Worst Case Daily Emissions – Stationary Sources, lbs/day

Pollutant	Maximum Hours Per Day	NOx	CO	VOC	SOx	PM10	PM2.5
CTG/HRSG	24	1,279.49	8,826.72	283.22	113.98	360.00	360.00
Coal Dryer	24	136.50	381.48	17.26	22.47	33.40	33.40
Auxiliary Boiler	24	31.20	189.60	20.40	9.60	25.68	25.68
Tail Gas Thermal Oxidizer	24	535.20	446.40	14.40	52.80	16.80	16.80
CO_2 Vent	24	--	11,808.00	264.00	--	--	--
Gasification Flare	10/24[b]	1,742.60	14,711.32	11.43	17.96	26.37	26.37
Rectisol® Flare	24	702.25	826.18	13.43	360.02	30.98	30.98
SRU Flare	24	59.24	69.70	1.13	441.62	2.61	2.61
Cooling Towers	24	--	--	--	--	144.00	86.40[a]
Emergency Generators	1	6.44	33.50	3.86	0.06	0.90	0.90
Fire Water Pump	2	3.68	6.37	0.34	0.01	0.04	0.04
Nitric Acid Unit	24	100.32	--	--	--	--	--
Urea Pastillation Unit	24	--	--	--	--	1.20	1.20
Ammonium Nitrate Unit	24	--	--	--	--	4.80	4.80
Ammonia Startup Heater	24	14.40	48.00	4.80	2.40	7.20	7.20
Material Handling	6-24[c,d]	--	--	--	--	1.02	1.02
Fugitives	24	0.00	32.88	88.08	0.48	--	--

Source: HECA 2013a, HECA 2013b
Notes:
[a] – The value in this table reflects the assumption of both the applicant and District that PM2.5 emissions are 60 percent of the total cooling tower emissions. Staff has issues with the technical validity of this assumption, and staff will be asking U.S. EPA to provide comment on this issue given the significance of PM2.5 health effects. However, this assumption does not affect whether the project would be deemed a major PM2.5 emissions source under PSD permitting regulations.
[b] – This represents 10 hours of flaring during a gasifier start-up and 24 hours of the flare pilot operation.
[c] – There are multiple material handling sources and the maximum daily use varies from 6, 8, 12, and 24 hours depending on the material handling source. The values shown assume all of these material handling sources operate on the same day.
[d] – The fluxant handling emissions are not included in these totals. The FSA will provide an updated table that includes the fluxant handling emissions.

Annual facility emission estimates, including the non-stationary source and net SJVAB feedstock transportation emissions, are provided in **Air Quality Table 17**, and are based on the following assumptions:

- The CTG/HRSG power block would have two startups/shutdown cycles per year, 8,000 hours per year of hydrogen-rich fuel operation, and 336 hours of natural gas operation.
- The coal dryer would have two startup/shutdown cycles per year and 8,000 hours per year of normal operation.
- The process block and ASU cooling towers are assumed to operate 8,322 hours/year, and the power block cooling tower is assumed to operate 8,668 hours/year.
- The auxiliary boiler is assumed to operate 2,190 hours/year based on a 213 MMBtu/hr heat input.
- Each of the emergency generator engines would operate 50 hours/year and the fire pump would operate for 100 hours/year.
- All three flares would have their natural gas fueled pilots operating 8,760 hours per year and each flare would operate with vented gases as follows: gasification flare – 2,386 to 2,926 MMBtu/hr heat input for a total of 10 hours during a startup and 2,413 MMBtu/hr for 4 hours during a shutdown with two startup/shutdown cycles occurring in a year; SRU Flare – 40 hours @ 36 MMBtu/hr heat input, and Rectisol® Flare – 40 hours @ 430 MMBtu/hr heat input pilot emissions only.
- Tail gas oxidizer would have normal full load operations for 8,318 hours/year with two startup events lasting a total of 48 hours per year.
- The CO_2 vent use is limited to 504 hours/year.
- The nitric acid unit and the urea pastillation unit are assumed to operate 8,052 hours per year.
- The ammonium nitrate unit is assumed to operate 8,000 hours per year.
- The ammonia startup heater is assumed to operate 140 hours per year at full capacity.
- Feedstock, urea, and gasification solids materials handling would occur from 1,248 to 8,760 hours per year depending on the specific material handling source (there are 18 separate sources with emissions calculations). The emissions estimate provided is for the solids material handling associated with Transportation Alternative 1, which forms the permitted emissions basis for the project that Alternative 2 would also have to achieve.
- Fugitive emissions are assumed to occur 8,760 hours per year.

Air Quality Table 17
Summary of Annual Operating Emissions, ton/yr

Pollutant	NOx	CO	VOC	SOx	PM10	PM2.5
Stationary Sources						
CTG/HRSG	106.50	89.00	15.10	17.10	54.00	54.00
Coal Dryer	17.00	12.70	2.40	2.80	5.60	5.60
Auxiliary Boiler	1.40	8.60	0.90	0.50	1.20	1.20
Tail Gas Thermal Oxidizer	13.40	11.20	0.30	8.30	0.40	0.40
CO_2 Vent	--	124.10	2.80	--	--	--
Gasification Flare	2.50	18.50	0.01	0.02	0.03	0.03
Rectisol® Flare	0.70	0.80	0.01	0.30	0.03	0.03
SRU Flare	0.10	0.20	0.00	0.40	0.01	0.01
Cooling Towers					25.50	15.30[a]
Emergency Generators	0.20	0.80	0.10	0.00	0.02	0.02
Fire Water Pump	0.09	0.20	0.01	0.00	0.00	0.00
Nitric Acid Unit	17.00	--	--	--	--	--
Urea Pastillation Unit	--	--	--	--	0.20	0.20
Ammonium Nitrate Unit	--	--	--	--	0.80	0.80
Ammonia Startup Heater	0.04	0.14	0.02	0.01	0.02	0.02
Material Handling[b]	--	--	--	--	2.30	2.30
Fugitives	0.00	6.01	16.71	0.11	--	--
Subtotal	**158.93**	**272.25**	**38.36**	**29.54**	**90.11**	**79.91**
Mobile Sources						
On-site trucks	0.99	0.63	0.16	0.01	0.15	0.05
On-site trains	2.38	0.85	0.12	0.06	0.04	0.04
Off-site workers commuting	0.48	4.17	0.13	0.01	1.05	0.28
Off-site trucks	8.71	5.29	0.74	0.06	2.39	0.72
Off-site trains	23.85	6.17	0.66	0.44	0.39	0.37
Subtotal	**36.41**	**17.11**	**1.81**	**0.58**	**4.02**	**1.46**
Project Total	**195.34**	**289.36**	**40.17**	**30.12**	**94.13**	**81.37**

Source: HECA 2013a, HECA 2013b
Notes:
a – The value in this table reflects the assumption by both the applicant and District that PM2.5 emissions are 60 percent of the total cooling tower emissions. Staff has issues with the technical validity of this assumption, and staff will be asking U.S. EPA to provide comment on this issue given the significance of PM2.5 health effects. However, this assumption does not affect whether the project would be deemed a major PM2.5 emissions source under PSD permitting regulations.
[b] – The fluxant handling emissions are not included in these totals. The FSA will provide an updated table that includes the fluxant handling emissions.

OEHI CO_2 EOR COMPONENT

The OEHI CO_2 EOR component is considered part of the whole of the project proposed. This subsection provides information on the air pollutant emissions sources and the current emission source estimates for the OEHI CO_2 EOR component. It should be noted that the OEHI CO_2 EOR component is expected to be evaluated in a separate CEQA document and will require a separate District air quality permitting action sometime after a decision is made on HECA by the Energy Commission. All of the information presented at this time on the OEHI CO_2 EOR component is preliminary and subject to change during those later formal regulatory evaluations.

Construction

Construction of the OEHI CO_2 EOR component would include the initial stationary facility construction and ongoing well drilling and construction requirements for moving the injection/production well grids over time, so construction occurs throughout the assumed 20-year CO_2 injection project life. The maximum annual and total estimated construction emissions during the 20-year construction period for the OEHI CO_2 EOR component are provided in **Air Quality Table 18**.

Air Quality Table 18
Total Estimated OEHI CO_2 EOR Component Construction Emissions, tons

	NOx	CO	SOx	VOC	PM10	PM2.5
Maximum Tons per Year [a]	59.11	47.62	0.06	2.39	6.68	6.68
Total (20-year period)	418.87	352.44	0.48	19.70	47.18	47.18
Annual Average (tons/year)	20.94	17.62	0.02	0.98	2.36	2.36

Source: HECA 2012s
Notes:
a. The maximum emissions for the criteria pollutants occur in different horizon years. The maximum emissions for NOx, VOC, CO and SOx are estimated to occur in 2023, while the maximum emission for PM10/PM2.5 is estimate to occur in 2015.

Operation

Air pollutant emissions during operation would occur from three general categories: permitted stationary sources, other stationary activities, and mobile sources. The operating emissions sources are described as follows:

CO_2 Injection Heater

The natural gas fired CO_2 injection heater would be used to maintain desired operating temperatures.

Triethlylene Glycol (TEG) Reboiler

The natural gas fired triethlylene glycol (TEG) reboiler would be used to dehydrate the recovered gases to the CO_2 water content specification. This early dehydration step would allow for the use of standard carbon steel material throughout the reinjection compression facility.

Amine Unit

The amine unit would remove the CO_2 and the sulfur compounds and would contain the natural gas fired nitrogen reinjection unit (NRU) heater.

Regeneration Gas Heater

The regeneration gas heater would be used to heat up the regeneration gas from the molecular sieve bed where the gas would be dehydrated to prevent ice or hydrate formation in the cold sections of the fractionation system.

Flares

OEHI proposes to use flares for the Central Tank Battery (CTB) and the Reinjection Compression Facility (RCF). These intermittent sources would operate only a few hours per year and would primarily have combustion emissions from the natural gas flame pilot gas.

Fire Pump Engines

The project is proposing two fire pump engines (175 hp each), one associated with the CTB and one associated with the RCF. The primary emissions from the fire pump engines would occur from diesel fuel combustion during routine readiness testing.

Fugitive and Tank Emissions

Fugitive emissions of VOC would occur due to minor leaks in the piping components and venting losses from storage tanks that service gases and liquids with a VOC content.

The maximum annual operating emissions for the OEHI CO_2 EOR component are provided in **Air Quality Table 19**.

Air Quality Table 19
Summary of OEHI CO_2 EOR Component Annual Operating Emissions, tons/yr

Pollutant	NOx	CO	VOC	SOx	PM10	PM2.5
Permitted Sources						
Injection Heater	2.77	12.05	1.78	0.91	2.48	2.48
Regeneration Gas Heater	0.46	2.01	0.30	0.15	0.41	0.41
TEG Heater	0.99	4.02	0.15	0.08	0.21	0.21
Amine Unit NRU Heater	0.13	0.80	0.06	0.02	0.04	0.04
CTB - Emergency Engine	0.01	0.00	0.00	0.00	0.00	0.00
RCF - Emergency Engine	0.01	0.00	0.00	0.00	0.00	0.00
CTB - Emergency Flare	--	--	--	--	--	--
RCF - Emergency Flare	--	--	--	--	--	--
Fugitive Emissions (VOC)	--	--	12.09	--	--	--
Tank Emissions (VOC)	--	--	2.12	--	--	--
Subtotal	**4.37**	**18.88**	**16.49**	**1.16**	**3.14**	**3.14**
Other Stationary Sources						
Stationary Source Activities	3.61	19.63	11.35	0.15	0.42	0.42
Max. Well Maintenance	0.96	1.16	0.25	0.00	0.04	0.04
Subtotal	**4.57**	**20.80**	**11.60**	**0.15**	**0.46**	**0.46**
Mobile Sources						
Employee Travel To Plants	0.09	1.16	0.04	0.00	0.02	0.02
Max. Travel to Well Sites	0.06	0.06	0.01	0.00	0.00	0.00
Subtotal	**0.15**	**1.21**	**0.04**	**0.00**	**0.03**	**0.03**
Project Total	**9.08**	**40.90**	**28.13**	**1.31**	**3.63**	**3.63**

Sources: HECA 2012s, OXY 2013c, OXY 2013e.

The emissions presented above in **Air Quality Table 19** are based on the maximum CO_2 recycle rate identified by OEHI (685 MMscfd) based on OEHI's current estimates for the permitted and other expected emission sources but do not include emissions from upset flaring events.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Energy Commission staff assesses four kinds of primary and secondary[9] impacts: construction, operation, closure and decommissioning, and cumulative. Construction impacts result from the onsite and offsite emissions occurring during site preparation and construction of the proposed project. Operation impacts result from the emissions of the proposed project during operation, which include all of the onsite equipment emissions (gas turbine, auxiliary boiler, flares, cooling towers, emergency engines, etc.), the onsite maintenance vehicle emissions, and the offsite employee and fuel delivery trip emissions. Closure and decommissioning impacts occur from the onsite and offsite emissions that would result from dismantling the facility and restoring the site. Cumulative impacts analysis assesses the impacts that result from the proposed project's incremental effect viewed over time, together with other closely related past, present, and reasonably foreseeable future projects whose impacts may compound or increase the incremental effect of the proposed project. (Pub. Resources Code § 21083; Cal. Code Regs., tit. 14, §§ 15064(h), 15065(c), 15130, and 15355.)

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

As discussed in the Introduction, this document analyzes the project's impacts pursuant to both NEPA and CEQA. The two statutes are similar in their requirements concerning analysis of a project's impacts. Therefore, unless otherwise noted, staff's use of, and reference to, CEQA criteria and guidelines also encompasses and satisfies NEPA requirements for this environmental document.

Energy Commission staff evaluates potential impacts per Appendix G of the CEQA Guidelines (AEP 2012). A significant adverse impact is determined to occur if potentially significant impacts cannot be mitigated through the adoption of conditions of certification. Specifically, Energy Commission staff uses health-based ambient air quality standards (AAQS) established by the ARB and the U.S. EPA as a basis for determining whether a project's emissions will cause a significant adverse impact under CEQA. The ambient air quality standards are set at levels that include a margin of safety and are designed to adequately protect the health of all members of the public, including those most sensitive to adverse air quality impacts such as the aged, people with existing illnesses, children, and infants. Staff evaluates the potential for significant adverse air quality impacts by assessing whether the project's emissions of criteria pollutants and their precursors (NOx, VOC, PM10 and SO_2) could create a new AAQS exceedance (emission concentrations above the standard), or substantially contribute to an existing AAQS exceedance.

Staff evaluates both direct and cumulative impacts. Staff will find that a project or activity will create a direct adverse impact when it causes an exceedance of an AAQS. Staff will find that a project's effects are cumulatively considerable when the project emissions in conjunction with ambient background, or in conjunction with reasonably foreseeable future projects, substantially contribute to ongoing exceedances of an

[9] Primary impacts potentially result from facility emissions of NOx, SOx, CO and PM10/PM2.5. Secondary impacts result from air contaminants that are not directly emitted by the facility but formed through reactions in the atmosphere that result in ozone, and secondary formation of PM10/PM2.5.

AAQS. Factors considered in determining whether contributions to ongoing exceedances are substantial include:

1. the duration of the activity causing adverse air quality impacts;

2. the magnitude of the project emissions, and their contribution to the air basin's emission inventory and future emission budgets established to maintain or attain compliance with AAQS;

3. the location of the project site, i.e., whether it is located in an area with generally good air quality where non-attainment of any ambient air quality standard is primarily or solely due to pollutant transport from other air basins;

4. the meteorological conditions and timing of the project impacts, i.e., do the project's maximum modeled pollutant impacts occur when ambient concentrations are high (such as during high wind periods, or seasonally);

5. the modeling methods, and how refined or conservative the impact analysis modeling methods and assumptions were and how that may affect the determined adverse impacts;

6. the project site location and nearest receptor locations; and whether the identified adverse impacts would also occur at the maximum impacted receptor location; and,

7. the potential for future cumulative impacts; and whether appropriate mitigation is being recommended to address the potential for impacts associated with likely future projects.

DIRECT/INDIRECT IMPACTS AND MITIGATION - HECA

The estimated project emissions represent the mass of pollutants emitted from the project, whereas the impacts are the concentration of pollutants from the project that reach the ground level. Total project emissions are a compilation of the emissions released from all the different emission points. When pollutants are released they are then subject to different physical and chemical forces that affect the way the pollutant travels through the atmosphere. For example, emissions that are expelled at high temperatures and velocity through relatively tall stacks will be significantly diluted by the time they reach ground level. The emissions from the proposed project are analyzed through the use of air dispersion models to determine the probable impacts at ground level.

Air dispersion models provide a means of predicting the location and ground level magnitude of the impacts of a new emissions source. These models consist of several complex series of mathematical equations, which are repeatedly calculated by a computer for many ambient conditions to provide theoretical maximum offsite pollutant concentrations for short-term (1-hour, 3-hour, 8-hour, and 24-hour) and annual periods. The model results are generally described as maximum concentrations, often described as a unit of mass per volume of air, such as micrograms per cubic meter ($\mu g/m^3$).

The applicant is required to use air dispersion modeling to demonstrate compliance with all CAAQS and NAAQS. The required analysis is determined by the attainment status of the project region and the expected annual emissions from the project. Modeling protocols were submitted by the applicant to the Energy Commission, SJVAPCD and U.S. EPA Region IX prior to the submittal of the AFC.

SJVAPCD District Rule 2201, NSR, requires an analysis of the impacts on ambient air quality from a new project. Any project that triggers public notice must include an analysis for all project units. Air quality modeling is used to demonstrate a project's regulated air pollutants would not cause or contribute to a violation of the applicable NAAQS or CAAQS. The analysis includes the impacts of the project in addition to the representative background concentrations of the regulated pollutants for all regulated criteria pollutants regardless of the attainment status. SJVAPCD can take into consideration mitigation of emissions through offsets when making the determination of compliance with the AAQS; however HECA did not take any credit for emission offsets in their modeling analysis.

SJVAPCD District Rule 2410, PSD, requires impacts on ambient air quality from a new PSD Major Stationary Source be examined. PSD requirements are applicable to major sources in areas that are designated in attainment of NAAQS. PSD for the project is triggered for CO, NO_2, PM10 and CO_2 however there are no NAAQS for CO_2. Therefore the applicable air pollutants for this demonstration are CO, NO_2 and PM10. Modeling is required to demonstrate that the facility's applicable air pollutant emissions will not cause or contribute to a violation of the applicable NAAQS, PSD increments, air quality related values (AQRV), visibility and soil and vegetation degradation.

For the PSD NAAQS compliance demonstration, a project's impacts can be compared to significant impact levels (SILs) established by U.S. EPA to determine if the project will cause or contribute to a NAAQS violation. SILs are screening tools used to determine whether a proposed source's emissions will have a significant impact on the ambient air quality in a region. A facility's air quality impacts are determined to be insignificant if the impacts are less than the corresponding SIL. More comprehensive, cumulative modeling analysis is not required for emission impacts below the corresponding SIL. Only stationary sources are included for comparison to the SILs.

The Energy Commission requires modeling for both the construction and operational phases of the project for compliance with CEQA. The modeling performed for the operational phase includes emissions from stationary sources, in addition to exhaust and fugitive dust from mobile sources that would be part of normal facility operations. Mobile sources include feedstock delivery, shipment of products, operations, and maintenance. The EMFAC 2007 model developed by CARB was used to calculate the emission rates from on-road vehicles. The EMFAC 2007 model is used instead of the updated EMFAC2011 model because the project is subject to NEPA as well as CEQA and EMFAC2011 has not yet been approved for federal projects. For CEQA compliance, project impacts in addition to representative background data are compared to the CAAQS.

Per U.S. EPA and SJVAPCD guidance, all modeling performed for PSD and NAAQS compliance includes permitted source emissions and does not include emissions from mobile sources. However, for CEQA compliance all modeling for compliance with CAAQS includes both the permitted source emissions and mobile source emissions.

The permitted sources are modeled using maximum potential emission rates from either normal or startup/shutdown operations to demonstrate compliance for all CAAQS and NAAQS with the exception of the NO_2 and SO_2 1-hour NAAQS modeling analysis. The applicant predicted NO_2 1-hour impacts from the project to be over the SIL. Therefore, a refined analysis was performed to demonstrate compliance with the NO_2 1-hour NAAQS. This refined analysis is a cumulative analysis that includes HECA's stationary sources and 371 existing permitted units within a 10 kilometer radius of the project site. In-stack NO_2/NOx ratios were developed for all of the HECA emissions sources and the cumulative emissions units using available regulatory guidance, and were approved by the SJVAPCD.

The applicant used the U.S. EPA guideline ARMS/EPA Regulatory Model (AERMOD) to estimate ambient impacts from project construction, commissioning and operation to demonstrate compliance with all CAAQS and NAAQS. AERMOD is able to model emission plumes from multiple point, area, or volume sources in flat, simple, and complex terrain using hourly meteorological data. The inputs to the model include stack information (exhaust flow rate, temperature, and stack dimensions), specific source emission data, meteorological data (wind speed and atmospheric conditions), and site elevation. The meteorological data used for the model included hourly wind speeds and directions measured at the Bakersfield Airport meteorological station from 2006 to 2010, located within 20 miles of the project site to the east northeast.

Emission sources from construction and operation were modeled as both point and area sources. The construction emission sources for the site were grouped into two categories: equipment (off-road equipment); and vehicles (on-road equipment). Emissions from the exhaust and fugitive dust for each group were calculated and impacts were modeled. The equipment exhausts were modeled as point sources and fugitive dust emissions were modeled as areas sources. Similar modeling procedures were used by the applicant to determine impacts from the operating emissions stationary sources, maintenance vehicle exhaust, and fugitive dust emissions.

For the determination of one-hour average and annual average construction, commissioning and annual operational NOx concentrations, the Plume Volume Molar Ratio Method (PVMRM) was used to determine worst-case near field NO_2 impacts. The NOx emissions from internal combustion sources, such as diesel engines, are primarily in the form of nitric oxide (NO) rather than NO_2. NO converts into NO_2 in the atmosphere, primarily through the reaction with ambient ozone. The PVMRM option determines the conversion rate for NO to NO_2 based on a calculation of the NO moles emitted into the plume and the amount of ozone moles contained within the volume of the plume.

Hourly meteorological data, hourly ozone data and in-stack NO_2/NOx ratios are required to conduct a PVMRM modeling analysis. The applicant obtained the meteorological data and hourly ozone data from SJVAPCD, and confirmed appropriate in-stack NO_2/NOx ratios through correspondence with SJVAPCD. The development of appropriate in-stack NO_2/NOx ratios is an ongoing science, with new information and understanding being developed over time. The default value was formerly 0.1; however, U.S. EPA has raised the default in-stack NO_2/NOx ratio to 0.5[10]. The use of other ratios is allowed by U.S. EPA if those values can be justified. The applicant has used in-stack NO_2/NOx ratios that range from 0.1 to 0.5 depending on the emissions source (HECA 2012e, Appendix E-7). Staff's review of the proposed in-stack NO_2/NOx ratios did not find any significant issues with the values used for the HECA emissions sources and, as noted above, these ratios were approved by the SJVAPCD.

The applicant followed U.S. EPA and SJVAPCD modeling guidelines in their air dispersion modeling analysis. The land immediately adjacent to the project site within approximately 2 miles is classified as rural. Therefore the AERMOD rural mode was used in the analysis. In addition, all HECA exhaust stacks would be less than or equal to the good engineering practice (GEP) default height of 65 meters except for the coal dryer, SRU Flare and CO_2 Vent. The actual coal dryer, CO_2 vent stacks and flare stacks are below the calculated GEP height values for these stacks. The stack heights of the flares used in the modeling were calculated based off of the GEP default height of 65 meters.

The applicant performed screening modeling with maximum emissions and conservative stack parameters in order to determine conservative worst case off-site impacts. The modeling assumed maximum emissions from each source regardless of whether the equipment modeled would actually be operating at these maximum conditions simultaneously. This methodology was used in order to determine conservative impacts without having to perform sensitivity modeling for each piece of equipment. Sensitivity modeling describes a more refined modeling that takes into account the actual operating parameters of the equipment and sequencing rather than using worst-case parameters and scenarios that may not represent actual operation. If the most conservative impact scenario complies with the AAQS then more in-depth modeling is not needed. Therefore if modeling assumes simultaneous worst case operations from all equipment and complies with the AAQS, then modeling using more realistic operating parameters and emissions is not needed to demonstrate compliance.

Staff reviewed the background concentrations provided by the applicant, replacing them where appropriate with the available highest ambient background concentrations from the last three years (2009 through 2011) at the most representative monitoring stations as shown in **Air Quality Table 6**. Staff's background data are different than the background values identified by the applicant for all pollutants except 1-hour NO_2, 1-hour SO_2, and 24-hour SO_2. The primary reason for the difference in background concentrations is that the applicant used background concentrations from 2008 through 2010 to determine background, while staff is using more recent background data that became available after the applicant completed their analysis. Staff added the modeled impacts to these background concentrations and then compared the results with the ambient air quality standards for each respective air contaminant to determine whether the proposed project's emission impacts would cause a new exceedance of an ambient air quality standard or would contribute to an existing exceedance.

[10] Higher in-stack NO_2/NOx ratios result in higher modeled impacts. Therefore, it is important not to underestimate these ratios when performing refined modeling analyses that use these in-stack ratios.

For construction emissions, the mitigation that is considered is limited to controlling both construction equipment tailpipe emissions and fugitive dust emissions to the maximum extent feasible. For operating emissions, the mitigation considered includes both feasible emission controls called best available control technology (BACT) and the use of emission reduction credits (ERCs) to offset emissions of nonattainment criteria pollutants and their precursors.

The following sections discuss the proposed project's short-term direct construction and operation ambient air quality impacts as estimated by the applicant, and describes appropriate mitigation measures.

Construction Impacts and Mitigation

Construction Modeling Analysis

The applicant modeled the construction emissions of the proposed project and evaluated the impacts within 10 kilometers using AERMOD (version 12060). Fugitive dust emissions from vehicles, on-site equipment and earthmoving equipment are modeled as area sources. Combustion exhaust emissions from vehicles and other on-site equipment are modeled as a series of point sources. The PVMRM option in AERMOD was used to determine NO_2 impacts. Data from the Shafter-Walker Street monitoring station was used to provide the hourly ozone concentration data used by the model. An initial in-stack NO_2/NOx ratio of 0.11 was assumed for the diesel-fueled construction equipment and heavy duty diesel truck NOx emissions and an initial NO_2/NOx ratio of 0.25 was assumed for the worker vehicle NOx emissions[11].

To determine the construction impacts on short-term ambient standards (i.e. 1-hour through 24 hours) the worst-case daily on-site construction emission levels shown in **Air Quality Table 8** were modeled. For pollutants with annual average ambient standards, the applicant used the summation of overall construction activities for the consecutive 12-month period that would produce the highest emissions of all pollutants. Modeling assumed that all of the equipment would operate 10 hours, from 6 am to 4 pm, daily. **Air Quality Table 20** provides the results of this modeling analysis of construction impacts.

The applicant's modeling results indicate that the project's construction impacts would not create violations of NO_2, SO_2 or CO standards, but could further exacerbate existing violations of the PM10 and PM2.5 standards. In light of the existing PM10 and PM2.5 nonattainment status for the project site area, staff considers the modeled impacts of PM and PM precursors to be significant and, therefore, require mitigation.

[11] These in-stack NO_2/NOx ratios are CAPCOA recommended values (CAPCOA 2011) for on-road heavy duty diesel trucks (0.11) and on-road light and medium duty gasoline vehicles (0.25), respectively. Staff notes that the applicant also used the 0.11 ratio for the off-road diesel equipment, although the CAPCOA recommendations for off-road equipment are either a default value of 0.2, or a value of 0.1564 presented for a 322 horsepower water pump. Staff may re-run the 1-hour NO_2 modeling analysis using the higher CAPCOA default off-road diesel equipment NO_2/NOx ratio, and if so will present those modeling results in the FSA.

Air Quality Table 20
HECA Construction Impacts, ($\mu g/m^3$)

Pollutant	Averaging Period	Project Impact ($\mu g/m^3$)	Background ($\mu g/m^3$) [a]	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Type of Standard	Percent of Standard
NO_2 [b,c]	1 hour	141	140	281	339	CAAQS	83%
	annual	3.2	24.7	27.9	57	CAAQS	49%
PM10	24 hour	48.8	238	287	50	CAAQS	574%
	annual	2.1	44.2	46.3	20	CAAQS	232%
PM2.5	24 hour	11.5	67	79	35	NAAQS	224%
	annual	0.6	21.2	21.8	12	CAAQS	182%
CO	1 hour	96.3	4,025	4,121	23,000	CAAQS	18%
	8 hour	25.3	2,411	2,436	10,000	CAAQS	24%
SO_2 [c]	1 hour	0.2	42	43	655	CAAQS	7%
	24 hour	0.03	13	13	105	CAAQS	12%

Source: HECA 2012d, HECA 2012e, HECA 2012dd
[a] Background values have been adjusted per staff recommended background concentrations shown in **AIR QUALITY Table 5**.
[b] Results for NO_2 during construction used PVMRM with ambient ozone data.
[c] U.S. EPA does not require evaluation of NAAQS for short-term impacts such as construction. Therefore, the 1-hour NO_2 and SO_2 construction impacts are compared to the 1-hour CAAQS standards. The PM2.5 24-hour modeled impact results compared against the NAAQS are shown only for informational purposes.

Construction Mitigation

As described in the “Laws, Ordinances, Regulations, and Standards” section, District Regulation VIII (i.e. Series 8000) limits fugitive dust emissions during the construction phase of a project. Staff recommends that construction emission impacts be mitigated to the greatest feasible extent including all feasible measures from the LORS, as well as other measures considered necessary by staff to fully mitigate the construction emissions.

Applicant’s Proposed Mitigation

The applicant has proposed the following emissions mitigation measures during construction (HECA 2012e).

Fugitive Dust Emissions Mitigation (applicant proposed measure AIR-1)

- Stabilize the main access roads through the facility with crushed rock or gravel for dust control;
- Use either water application, chemical dust suppressant application, or other suppression technique to control dust emissions from on-site unpaved road travel and unpaved parking areas;
- Cover all trucks hauling soil, sand, and other loose materials or require all such trucks to maintain at least two feet of freeboard;
- Limit traffic speeds on all unpaved site areas to 15 miles per hour;
- Install sandbags or other erosion control measures to prevent silt runoff to roadways;
- Replant vegetation in disturbed areas as quickly as possible;

- Inspect and wash as necessary vehicle tires prior to exiting construction site onto paved roadways; and
- Mitigate fugitive dust emissions from wind erosion on areas disturbed by construction activities (including storage piles) by application of either water, chemical dust suppressant, or other suppression techniques.

Exhaust Emissions Mitigation (applicant proposed measure AIR-2)

- Properly maintain and tune engines to the engine manufacturer's specifications;
- Limit the engine idle time to no more than five minutes for heavy diesel construction equipment that does not need to idle as part of their normal operation;
- Use low sulfur and low aromatic fuel meeting California standards for motor vehicle diesel; and
- Use low-emitting gas and diesel engines meeting state and federal emissions standards (Tiers 2 and 3) for construction diesel engines with a rating of 50 horsepower or higher.

The applicant's construction emissions estimates in **Air Quality Tables 8** and **9** and construction modeling results in **Air Quality Table 20** include the effect of all of the emissions reduction measures noted above except the use of higher tier off-road engines. The off-road equipment emission estimates were based on the OFFROAD model's fleet average emission factors for Kern County in 2013, which includes some lower tier (i.e., higher emitting) engines.

Adequacy of Proposed Mitigation

The applicant's fugitive dust emission mitigation measures are not as comprehensive or as restrictive as they could be to control fugitive dust emission from all activities during construction. For example the applicant's proposed measure doesn't have street sweeping requirements, doesn't restrict speed to be as low as possible on unpaved roads, doesn't require paving of the onsite roads as soon as possible, and has no compliance assurance requirements. Staff believes that all reasonable construction emission mitigation measures with adequate compliance assurance measures should be implemented to mitigate the potentially significant construction PM10 and PM2.5 impacts.

The applicant's proposed off-road engine emissions mitigation is very similar to the mitigation measure that staff has recommended in the past, particularly in terms of required off-road engine tier requirements. However, staff updates its engine mitigation measure periodically to include higher off-road engine tier requirements as reasonable based on the dates when higher engine tier standards become effective for new model year engines. Staff considers the applicant's engine emissions mitigation to be a bit dated, and based on engine availability it does not provide adequate ozone precursor (NOx and VOC) and diesel particulate matter (DPM) mitigation.

Staff Proposed Mitigation

Staff is recommending construction emissions mitigation measures that are more stringent than those proposed by the applicant. However, staff's proposed measures do not include certain emission reduction measures (such as use of ARB low sulfur diesel) that are explicitly required already by existing state regulations. Staff's recommended Conditions of Certification **AQ-SC1** through **AQ-SC5** include several additional or more stringent construction fugitive dust PM10 emission mitigation measures and more stringent off-road equipment mitigation to assure maximum feasible fugitive dust control performance and construction equipment exhaust emissions control, as well as adding compliance assurance requirements.

Staff recommends **AQ-SC1** to require the applicant to have an onsite construction mitigation manager who would be responsible for the implementation and compliance of the construction mitigation program. The documentation of the ongoing implementation and compliance with the construction mitigation program would be provided in the monthly construction compliance report that is required in staff's recommended Condition of Certification **AQ-SC2**.

Staff incorporated and augmented the applicant's proposed fugitive dust mitigation measures and recommends that the fugitive dust mitigation measures be formalized in Condition of Certification **AQ-SC3**. **AQ-SC3** includes several additional mitigation measures to control fugitive dust emissions and requires that District Regulation VIII rule requirements apply when they are more stringent.

Staff recommends Condition of Certification **AQ-SC4** to require visible dust plume response requirements that would limit the potential offsite impacts from visible dust emissions from the construction activities.

Staff recommends Condition of Certification **AQ-SC5** to require the use of new off-road equipment that would meet the highest level of emissions reductions available for the engine family of the equipment being used by requiring the use of the latest available U.S. EPA/ARB Tier level including Tier 4 or Tier 4i engines or when Tier 4 engines are not available requiring add-on emissions controls where feasible, which would significantly reduce the NOx and diesel particulate emissions from off-road equipment.

Based on the relatively short-term nature of the worst-case construction impacts, which would occur during the initial grading phase of the first few months of construction, and staff's recommendation of requiring all feasible construction emission mitigation measures, staff believes that the construction air quality impacts would be less than significant with the implementation of staff-recommended mitigation measures contained in the conditions of certification.

Operation Impacts and Mitigation

The following section discusses the project's direct ambient air quality impacts as estimated by the applicant and evaluated by staff. Additionally, this section discusses the recommended mitigation measures.

Operational Modeling Analysis

The applicant performed direct impact modeling analyses, including normal operations, fumigation (see text below for definition), and initial commissioning impact modeling.

A refined dispersion modeling analysis was performed to identify off-site criteria pollutant impacts that would occur from routine operational emissions throughout the life of the project. This impact analysis includes both maximum operating and startup/shutdown scenarios to determine worst-case air quality impacts on both a short-term and an annual basis. The operating profiles are shown in **Air Quality Table 11** to **Air Quality Table 17**. These conditions were modeled to determine the worst case short term impacts. The predicted maximum concentrations of these pollutants are summarized in **Air Quality Table 21**.

Air Quality Table 21
HECA Operating Impacts, (µg/m³)

Pollutant	Averaging Period	Project Impact (µg/m³)	Background (µg/m³) [a]	Total Impact (µg/m³)	Limiting Standard (µg/m³)	Type of Standard	Percent of Standard
NO_2	1 hour state	185	140	325	339	CAAQS	96%
	1 hour fed	-- [c]	83.3 [b]	126 [c]	188	NAAQS	67%
	Annual state	1.5	24.7	26.1	57	CAAQS	46%
	Annual fed [d]	0.6	24.7	25.3	100	NAAQS	25%
PM10	24 hour state	4.9	238	243	50	CAAQS	486%
	24 hour fed	4.9	97	102	150	NAAQS	68%
	annual	0.8	44.2	45	20	CAAQS	225%
PM2.5	24 hour	3.1	67	70	35	NAAQS	200%
	annual	0.6	21.2	21.8	12	CAAQS	182%
CO	1 hour	2,663	4,025	6,688	23,000	CAAQS	29%
	8 hour	371	2,411	2,782	10,000	CAAQS	28%
SO_2	1 hour state	50	42	92	655	CAAQS	14%
	1 hour ed [e]	50	24	74	197	NAAQS	38%
	3 hour	29	24	53	1,300	NAAQS	4%
	24 hour	6	13	19	105	CAAQS	18%

Source: HECA 2012d, HECA 2012e
[a] Background values have been adjusted per staff recommended background concentrations shown in **Air Quality Table 6**.
[b] The background is provided for informational purposes only as it is a statistical background that cannot be directly added to determine impacts for this standard.
[c] The project impacts and hourly NO_2 background values are a combined, or paired, cumulative modeling analysis which predicts the total cumulative impacts of the project's emissions sources and the other 371 cumulative permit units within 10 kilometers of the project site that were included in the modeling analysis based on the statistical 98th percentile of the maximum daily 1-hour values.
[d] The difference between the state and federal impacts are that the state impacts include mobile source emissions.
[e] This provides an addition of the 99th percentile background plus the maximum hourly facility impact, which overstates a combined, or paired, 99th percentile value. However, this conservative approach clearly shows compliance with the NAAQS.

The applicant's modeling results combined with staff-recommended background concentrations indicate that the project's normal operational impacts would not create violations of the NO_2, SO_2 or CO standards. Results indicate the project could further exacerbate existing violations of the PM10 and PM2.5 standards. In light of the existing PM10 and PM2.5 nonattainment status for the project site area, staff considers the modeled impacts of PM and PM precursors to be significant and, therefore, require mitigation.

Fumigation Modeling Impact Analysis

Fumigation describes a meteorological condition where a plume is released below an inversion layer. Plume pollutants can be rapidly transported to ground-level during these conditions as the inversion layer begins to become unstable. High, short-term concentrations may potentially occur during fumigation conditions. In the early morning hours before sunrise, the air is usually very stable. During stable meteorological conditions, emissions from elevated stacks rise through the stable layer and are dispersed aloft. When the sun first rises, the air at ground level is heated, resulting in a vertical mixing of air. Stack emissions entering this vertically mixed layer of air will also be vertically mixed, resulting in a transport of emissions down to ground level. Later in the day, as the sun continues to heat the ground, this vertical mixing layer becomes higher and higher, allowing emissions plumes to disperse. The early morning fumigation event is a transitory condition usually lasting approximately 30 to 90 minutes.

A fumigation analysis was performed using U.S. EPA model SCREEN3. Due to the transitory nature of fumigation, a given receptor may only be impacted for a brief time. Therefore hourly impact model predictions are used for fumigation modeling. The applicant analyzed the maximum one-hour air quality impacts under fumigation conditions from the CTGs/HRSG unit, coal dryer, tail-gas thermal oxidizer and nitric acid plant. The results of the analysis, as shown in **Air Quality Table 22**, indicate that the maximum one-hour fumigation impacts would be lower than the maximum operating emission impacts under normal meteorological conditions, as shown above in **Air Quality Table 21**.

Air Quality Table 22
Maximum HECA Fumigation Impacts, (μg/m³)

Pollutant	Averaging Period	Project Impact (μg/m³)	Background (μg/m³) [a]	Total Impact (μg/m³)	Limiting Standard (μg/m³)	Type of Standard	Percent of Standard
NO_2	1 hour	42.9	140	183	339	CAAQS	54%
SO_2	1 hour	2.7	42	45	655	CAAQS	7%
CO	1 hour	282	4,025	4,307	23,000	CAAQS	19%

Source: HECA 2012d, HECA 2012e
[a] Background values have been adjusted per staff recommended background concentrations shown in **Air Quality Table 6**.

Initial Commissioning Short-Term Modeling Impact Analysis

The applicant modeled the commissioning emissions to determine worst-case short-term operating impacts for the project. Emissions from individual pieces of equipment during initial commissioning can be significantly higher than normal operations. For example, the maximum hourly emissions of NOx and CO from the CTG/HRSG are elevated during certain initial commissioning steps. However, there would be limited pieces of equipment operating during each commissioning step, so the resulting total project impacts during commissioning may or may not be greater than those that would occur under normal operations. The applicant presented several initial commissioning scenarios that represent worst-case emission combinations that could occur prior to meeting normal emission limits. The scenarios analyzed are described below as labeled by the applicant.

- Case 1: Modeling analysis for SO_2 (1-hour and 24-hour), NO_2 (1-hour), CO (1-hour and 8-hour) and PM10 (24-hour) for testing of either of the emergency diesel generator engines while cooling tower is at reduced or no load. This occurs early in the commissioning sequence during utility and support system commissioning.
- Case A: Modeling analysis for CO only during initial first fire operation of the combustion turbine on natural gas at 20 percent load prior to the operation of the SCR and oxidation catalyst. The power block cooling tower is also operating at a reduced load during this scenario.
- Case B: Modeling analysis for SO_2 and NO_2 during tuning the water injection rates, operation of the combustion turbine on natural gas at 80 percent load prior to the operation of the SCR and oxidation catalyst.
- Case A2: Modeling NO_2, CO and PM10 during initial operation of the gasifier at 50 percent load while flaring sweet unshifted syngas in the gasification flare. The HRSG and coal dyer would be operated on natural gas at 80 percent load, operation of the three cooling towers and the tail gas thermal oxidizer.
- Case B2: Modeling of SO_2 during late in the start-up sequence when shifted syngas is sent to the gasification flare while all three cooling towers are operational. This scenario anticipates a brief excursion in the SO_2 emissions from the tail gas thermal oxidizer before the tail gas is recycled to the shift converters.
- Case C2: Modeling CO during gasifier operation at 50 percent load while flaring hydrogen-rich fuel gas in the gasification flare. This occurs during the transition period prior to the gas turbine switching to hydrogen rich fuel and CO_2 is vented prior to the CO_2 compressor being ready to send CO_2 to OEHI. Power block operation is at 80 percent load fired on natural gas; thermal oxidizer and cooling towers are operational.
- Case D2: Modeling NO_2 during gasifier operation at 50 percent load while commissioning the PSA unit. Hydrogen rich gas and off-gas is sent to the gasification flare, CO_2 is being sent offsite, power block operation is at 80 percent load fired on natural gas, the thermal oxidizer and all three cooling towers are operational.
- Case E2: Modeling NO_2 and CO during gasifier operation at 50 percent load and gas turbine operation at 40 percent load with surplus hydrogen rich fuel being sent to the gasification flare. This follows the turbine transition from natural gas to hydrogen rich gas. CO_2 may be vented during this period; thermal oxidizer and all three cooling towers are operational.
- Case A3: Modeling was not analyzed for this scenario because all the pollutants are overlapped or covered in other scenarios. The scenario included the commissioning of the ammonia and urea units when hydrogen is flared and purified CO_2 is vented prior to the conversion to products. The gasification block, thermal oxidizer and all three cooling towers are operational, and power block operation is at 100 percent load fired on hydrogen-rich gas.
- Case B3: Modeling SO_2, NO_2 and CO under Case A3 with the ammonia synthesis start-up heater operating.

- Case C3: Modeling NO_2 and PM10 during commissioning of the nitric acid unit. The gasification block, ammonia and urea units, three cooling towers and thermal oxidizer are operational. Power block operation is at 100 percent load fired on hydrogen-rich fuel.

These emission scenarios were modeled using the AERMOD model to determine maximum commission impacts. The modeling conducted does not include any overlap from construction activities. Since the commissioning operations are limited term activities, impacts are not compared to the federal NO_2 and SO_2 1-hour standards which are based on long-term statistical averaging periods. The results of the commissioning emissions modeling analysis are shown in **Air Quality Table 23.** As shown in the table below, the worst-case emissions would not cause an exceedance of the one-hour NO_2 standard or the one-hour and eight-hour CO standards. Therefore, the modeling results indicate that the commissioning emissions, and by comparison the startup emission impacts, do not have the potential to cause significant short-term ambient air quality impacts.

Air Quality Table 23
Maximum HECA Initial Commissioning Impacts

Pollutant	Averaging Period	Project Impact ($\mu g/m^3$)	Background ($\mu g/m^3$) [a]	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Type of Standard	Percent of Standard
CO (Case A)	1 hour	1,975	4,025	6,000	23,000	CAAQS	26%
	8 hour	801	2,411	3,212	10,000	CAAQS	32%
NO_2 (Case B)	1 hour	150	140	290	339	CAAQS	86%
PM10 (Case A2)	24-hour	3.4	238	241	50	CAAQS	483%
SO_2 (Case B2)	1 hour	97.4	42	139	655	CAAQS	21%
	3 hour	37.5	24	62	1300	NAAQS	5%
	24 hour	7.5	13	21	105	CAAQS	20%

Source: HECA 2012d, HECA 2012e
[a] Background values have been adjusted per staff recommended background concentrations shown in **Air Quality Table 6**.

Odor Impacts

HECA would emit several substances in high enough concentrations that they could possibly cause offensive odors. Specifically, the substances of concern for HECA would be hydrogen sulfide (H_2S), carbonyl sulfide (COS), carbon disulfide (CS_2), and ammonia (NH_3). The project would also have minimal emissions of a few other odorous compounds (acetaldehyde, naphthalene, phenol); however, given their emission levels, odor thresholds, and release/dispersion characteristics, staff concludes that no adverse odor impacts are likely to occur from these other substances. The applicant modeled H_2S emissions to determine the potential for H_2S odor impacts. This substance has a higher emissions rate and a lower odor threshold than the other reduced sulfur compounds so it provides a worst-case odor potential of the reduced sulfur compounds.

The odor thresholds for the four substances of concern are as follows:

Odorous Compound	Odor Threshold
Hydrogen sulfide	0.0005 ppm

Carbon disulfide	0.0081 ppm
Carbonyl sulfide	0.1 ppm
Ammonia	17 ppm

The applicant completed modeling to determine the maximum concentration of H_2S beyond the property fence line. This modeling showed that the concentrations predicted were less than the CAAQS, which is approximately the mean odor threshold. The modeling results showed a worst-case hourly impact of 23 $\mu g/m^3$ versus the 1-hour CAAQS of 42 $\mu g/m^3$ (0.03 ppm).

Staff believes that the use of 1-hour average concentrations for odor impact determination is problematic because odor impacts can occur over a much shorter duration than a 1-hour period with concentrations above the odor threshold for a short period even if the impact is below the mean odor threshold when averaged over a full hour. Additionally, the H_2S odor threshold for sensitive individuals is much lower than the mean odor threshold (i.e., the 0.0005 ppm lower odor threshold for H_2S identified above is much lower than 0.03 ppm mean odor threshold used to set the CAAQS). Therefore, staff believes that there is the potential for H_2S odors from HECA emissions sources to be perceived beyond the fence line. It is very important to note that there is a difference between perceiving an odor and for that odor to become a public nuisance. While staff does not believe that the H_2S CAAQS provides a clear demarcation for perceiving H_2S odors, we acknowledge that ARB's stated purpose for this standard is to protect public health and to significantly reduce odor annoyance. Additionally, the potential for public exposure to these concentrations is limited given the low population immediately surrounding the project site. Therefore, while staff believes that H_2S odors may be able to be perceived beyond the fence line during worst-case meteorological conditions, these odors per the CEQA Guidelines Appendix G part III. Air Quality e) are not likely to "create objectionable odors affecting a substantial number of people" and thus they are not likely to be significant problematic odors.

Comparing the odor thresholds and the emissions (see the Public Health Table 6) of the other reduced sulfur compounds with H_2S, staff concludes that there is not likely to be adverse odor impacts from the normal operating emissions of CS_2 and COS.

Ammonia would be emitted in much higher quantities than the reduced sulfur compounds, but it also has a much higher odor threshold. Ammonia emissions from the stationary and fugitive sources were included in the Health Risk Assessment (HRA) modeling for the project, which is presented in the **Public Health** section of the DEIS/PSA. The Office of Environmental Health Hazard Assessment acute reference exposure level for ammonia is lower than the odor detection threshold for ammonia (3,200 $\mu g/m^3$, or 4.6 ppm), and staff found that the maximum concentrations under normal operations were well below the acute reference exposure level. Therefore, ammonia concentrations from the HECA emissions sources would be well below the odor detection level and would not be detectable under normal operating conditions.

In conclusion, while staff believes that during normal operations HECA would not create odor impacts that would create a public nuisance, there is the potential for H_2S odors to be perceived beyond the fence line. Additionally, there would be the potential for odor impacts during equipment upset events. However, HECA would be required to correct equipment upsets expeditiously in compliance SJVAPCD rules and regulations.

Air Quality Related Values (AQRVs)

The analysis of air quality related values (AQRVs) concerns impacts to resources that are sensitive to air pollution, and includes the analysis of impacts to soils and vegetation and visibility. The Federal Land Manager (the representative of the agency of jurisdiction) reviewed the applicant's initial emissions over distance (Q/d) analysis and determined that the project would have less than significant impacts for all AQRVs (HECA 2012q). However, the applicant completed analysis related to impacts to soils and vegetation and visibility per the request of U.S. EPA Region 9. Each is described next.

Soils and Vegetation

A soils and vegetation impact analysis is required under the federal Prevention of Significant Deterioration (PSD) permitting program. The analysis includes both a screening analysis to determine if maximum modeled ground-level concentrations of the project impact plants and a discussion of soils and vegetation that may be affected by proposed project emissions and associated impacts. The applicant provided an analysis in the PSD application submitted to SJVAPCD. The applicant followed a U.S. EPA established screening procedure for determining impacts to plants, soils, and animals from emissions of NO_2, SO_2, PM10, H_2S and CO from the project. In addition HECA provided a detailed discussion on the surrounding vegetation. The modeled impacts of NO_2, SO_2, PM10, H_2S and CO emissions combined with background concentration data are below the screening concentrations identified in the screening procedures. The results are summarized in **Air Quality Table 24**.

Air Quality Table 24
Soils and Vegetation Results

Pollutant	Modeled Averaging Time	Predicted Impact ($\mu g/m^3$)	Background ($\mu g/m^3$) [b]	Total Impact ($\mu g/m^3$)	U.S. EPA AQRV Screening Concentration ($\mu g/m^3$)	U.S. EPA AQRV Screening Averaging Time	Percent of Screening
SO_2	1 hour	50	42	92	917	1 hour	10%
	3 hour	29	26	55	786	3 hour	7%
	Annual	0.1	13	13.1	18	Annual	73%
NO_2	1 hour	185	140	325	3,760	4-hour & 8-hour	9%
					564	Weekly	58%
	Annual	1.5	24.7	26.2	94	Annual	27%
PM10	24 hour	4.9	97	102	N/A	N/A	N/A
	Annual	0.8	44.2	45.0	N/A	N/A	N/A
CO	8 hour	371	2,411	2,782	1,800,000	Weekly	0.15%
H_2S	1 hour	23	N/A	23	28,000	4 hour	0.08%

Source: HECA 2012j and PDOC (SJVAPCD 2013a)
[a] Background values have been adjusted per staff recommended background concentrations shown in **Air Quality Table 6**.

The modeling results summarized in **Air Quality Table 24** show impacts that are well under the U.S. EPA AQRV screening concentrations. Therefore, it is concluded that emissions associated with the project would not generally result in adverse impacts to soils or vegetation.

Visibility Impacts

A visibility analysis of the project's gaseous emissions is required under the federal Prevention of Significant Deterioration (PSD) permitting program. The potential for visibility impairment is characterized for Class I areas located within 50 km of the proposed site and Class II areas identified as potentially sensitive state or federal parks, forests, monuments or recreation areas. The nearest Class I area is San Rafael Wilderness which is approximately 60 km away from the project, which is beyond the 50 km threshold for analysis. Therefore, the applicant did not evaluate visibility impacts to Class I Areas. U.S. EPA Region 9 requested that a Class II visibility analysis for Sequoia National Forest and Los Padres National Forest be performed. Sequoia National Forest is 54 kilometers away and Los Padres National Forest is 49 kilometers away from the project site. The applicant proposed a methodology and threshold similar to Class I areas because the EPA has not established a quantitative visibility impairment threshold for Class II areas. This visibility screening modeling analysis compares the project's impacts against visual screening criteria for total color contrast (Delta E) and plume contrast. The results of the applicant's VISCREEN analysis are shown **Air Quality Table 25.**

Air Quality Table 25
Class II Visibility Results

Maximum Visual Impacts Inside Area Screening Criteria Are Not Exceeded								
Background	Theta	Azimuth	Distance	Alpha	Delta E		Contrast	
					Criteria	Plume	Criteria	Plume
SKY	10	142	15	27	2	1.765	0.05	0.013
SKY	140	142	15	27	2	0.532	0.05	-0.012
TERRAIN	10	84	11	84	2	1.932	0.05	0.019
TERRAIN	140	84	11	84	2	0.291	0.05	0.01

Source: HECA 2012ff and PDOC (SJVAPCD 2013a)

The modeling results summarized in **Air Quality Table 25** show plume impacts for the two Class II areas that are below the Delta E and Contrast screening criteria for Class I areas. Staff concludes that emissions associated with the project would not generally result in adverse impacts to visibility.

Growth

A growth impact analysis is required under the federal Prevention of Significant Deterioration (PSD) permitting program. The analysis includes a discussion of general commercial, residential, industrial, and other growth associated with the project. The applicant provided a discussion of potential growth impacts that would likely occur to support the project. Topics include population, housing, economic base and employment. The SJVAPCD determined that the project would not cause any significant population increases or associated growth. In the **Socioeconomics** section of the

PSA/DEIS staff also concluded that the project would not induce substantial population growth, displacement of population, or demand for housing and public services.

Operations Mitigation

As described in the "Laws, Ordinances, Regulations, and Standards" section, District NSR Rule 2201 establishes emission and operation requirements. Staff recommends operating emission impacts be mitigated to the greatest feasible extent including all feasible measures from the LORS, as well as other measures considered necessary by the District and staff to fully mitigate the emissions.

BACT requirements for this project are triggered on a per pollutant basis for each emissions unit with a potential to emit greater than 2 lbs/day. BACT is not required for ammonia emissions resulting from the operation of the SCR unit since the SCR unit is a control device used to meet BACT for NOx. Ammonia emissions are quantified and limited according to the applicants proposed slip limits[12]. The following reflects measures to meet both BACT requirements and applicant-proposed mitigation.

Proposed Mitigation

Emissions Control Mitigation for Each Process Unit

CTG/HRSG Combustion Turbine (excluding Startup/Shutdown conditions)

NOx: The PDOC identifies selective catalytic reduction limiting emission levels to 2.5 ppmvd (1-hour average) and 4 ppmvd (3-hour average) @ 15 percent O_2 for hydrogen-rich and natural gas fuel respectively as BACT. The applicant has proposed a 3-hour averaging period when operating on hydrogen-rich fuel, and they are proposing SCR technology to meet these limits.

CO: The PDOC identifies an oxidation catalyst achieving emission levels of 3.0 ppmvd and 5.0 ppmvd @ 15 percent O2 (3-hour average) for hydrogen-rich and natural gas fuels, respectively as BACT. The applicant is proposing an oxidation catalyst to meet these limits.

VOC: The PDOC identifies an oxidation catalyst achieving emission levels of 1.0 ppmvd and 2.0 ppmvd @ 15 percent O2 (3-hour average) for hydrogen-rich and natural gas fuels, respectively as BACT. The applicant is proposing an oxidation catalyst to meet these limits.

PM10: The PDOC identifies an air inlet cooler/filter tube, lube oil vent coalescer and 0.003 lb SOx/MMBtu when firing on hydrogen-rich fuel exclusively, or either PUC-regulated natural gas or non-PUC regulated natural gas with no more than 0.75 grains sulfur (S)/100 dry standard cubic feet (dscf) as BACT. The applicant is proposing to meet these limits with the necessary equipment or equivalent, meet 0.003 lb SOx/MMBtu when firing on hydrogen-rich fuel and the use of PUC-regulated natural gas.

[12] Quantification of the proposed project's ammonia emissions are presented in the Public Health section of this document, in **Public Health Tables 5** and **6**.

SO_X: The PDOC identifies PUC –regulated natural gas, non-PUC regulated natural gas with no more than 0.75 grain S/100 dscf or 0.003 lb SOx/MMBtu when firing on hydrogen-rich fuel as BACT. The applicant is proposing to meet these limits through the use of PUC-regulated natural gas and hydrogen-rich fuel meeting 0.003 lb SOx/MMBtu.

NH_3: The applicant is proposing 5 parts per million by volume, dry (ppmvd) at 15 percent O_2 on hydrogen-rich fuel and natural gas fuel.

Railcar Unloading and Transfer System, Truck Unloading and Transfer System, Feedstock Grinding/Crushing and Drying System, Gasification Solids Handling System and Urea Storage and Handling Operation

PM10: The PDOC identifies storage, mixer, augers, elevators, and conveyors to all be enclosed and vented to a fabric filter baghouse as BACT for dry material handling storage and conveying. The baghouse particulate emissions are not to exceed 0.001 grains/dscf. Visible emissions from transfer points are limited to 5 percent opacity.

In addition the PDOC requires water spray dust suppression in the coal/petcoke unloading stations and the storage enclosure when unloading.

The applicant is proposing to use water spray and other dust suppression techniques to control emissions during train and truck unloading of coal and petcoke. The applicant is also proposing to fully enclose handling, conveying and storage system and vent emissions to be controlled with fabric filter baghouses to meet these BACT requirements.

Fugitive Emissions from Gasification System, and Sulfur Recovery System

VOC: The PDOC defines leaks as a reading of methane in excess of 100 ppmv above background for valves and 500 ppmv above background for pump and compressor seals when measured using EPA Method 21 and an inspection and maintenance program pursuant to District Rule 4455 as BACT. The applicant is proposing a leak detection and repair program for valves and connectors with VOC above 100 ppmv and pumps and seals with VOC above 500 ppmv.

Sulfur Recovery System

SOx: The PDOC identifies the use of a sulfur recovery unit with tail gas treating unit to limit the sulfur recovery system to 10 ppmv H_2S (three hour moving average) or less and a standby incinerator, except during startup and shutdown as BACT. The applicant is proposing this equipment and would meet the limit.

CO_2 Recovery and Vent System

CO and VOC: The PDOC identifies capture, compression and transportation of the exhaust stream in a pipeline for injection (during normal operation): venting due to upset condition up to 504 hours (or equivalent) per rolling 12 month period as BACT. The applicant is proposing equipment and would meet the limit.

Auxiliary Boiler

NOx: The PDOC identifies limiting emission levels to 5 ppmvd @ 3 percent O_2 as project specific BACT. The applicant is proposing SCR technology to meet this limit.

VOC, SOx, CO, PM10: The PDOC identifies using natural gas with LPG backup as BACT. The applicant is proposing to use PUC-quality natural gas.

Cooling Towers

PM10: The PDOC identifies a cellular type drift eliminator as BACT. The applicant is proposing a cellular type drift eliminator with a 0.0005 percent drift as percent of the amount of recirculating water, total dissolved solids limit and good operating practices.

Flares

NOx: The PDOC identifies an engineered flare or enclosed burner with air or stream assisted combustion, staged combustion and/or equivalent District approved controls and demonstrated NOx emissions of less than 0.068 lb/MMBtu equipped with a flare gas recovery system for non-emergency releases as BACT.

CO: The PDOC identifies an engineered flare with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls and a flare gas recovery system as BACT.

VOC: The PDOC identifies an enclosed ground level flare or any other engineered flare designed with a VOC destruction efficiency of 98.5 percent or greater.

PM10: The PDOC identifies an engineered flare with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls and a flare gas recovery system as BACT.

SO_X: The PDOC identifies a flare with a flare gas recovery system for non-emergency releases, and natural gas as the pilot and purge gas as BACT.

The applicant is proposing a natural gas piloted flare with good combustion practices, and limited operations, that would meet the other emission limit and destruction efficiency requirements listed above for the Gasification, Rectisol®, and SRU flares. Additionally, the applicant is proposing the use of a caustic scrubber to remove sulfur from the gases prior to their destruction in the SRU flare.

Ammonia Synthesis Startup Heater

NOx: The PDOC identifies 9 ppmvd @ 3 percent O_2 as BACT. The applicant is proposing a low NOx burner to meet these requirements, CO, VOC, SOX, PM10: The PDOC identifies PUC- quality natural gas firing as BACT. The applicant is proposing PUC-quality natural gas.

Nitric Acid Unit

NOx: The PDOC identifies extended absorption and/or catalytic reduction limiting NOx emission to 0.20 lb/ton of nitric acid produced (expressed as 100 percent nitric acid on a 24 hour rolling average basis) as BACT. The applicant is proposing a low NOx burner to meet these requirements.

Ammonium Nitrate Unit

PM10: The PDOC identifies a wet scrubber limiting emissions to 0.0075 lb-PM10/ton of ammonium nitrate produced. The applicant is proposing a wet scrubber to meet this limit.

Two Emergency Diesel Generators, 2,922 hp and One Emergency Firewater Pump Engine, 565 hp

NOx/CO/VOC/PM10: The PDOC identifies the latest EPA Tier Certification level for the applicable horsepower range as BACT.

SO_X: The PDOC identifies very low sulfur diesel of 15ppmv or less as BACT.

The applicant is proposing the use of interim Tier 4 engines fueled by low sulfur diesel fuel to meet these BACT requirements. The applicant would be required to obtain equipment meeting final Tier 4 emissions standards if that tier level is applicable at the time of installation.

Emission Offsets

As documented in **Air Quality Table 4**, the SJVAPCD is in non-attainment with AAQS for O_3, PM10, and PM2.5. The California Energy Commission requires mitigation for the emissions of pollutants and/or their precursors that are in non-attainment with state and federal air quality standards or may result in any violation of any air quality standard. Precursors of O_3, PM10, and PM2.5 include VOC, SOx, and NOx. Therefore mitigation is required for PM10, PM2.5, SOx, NOx, and VOC emissions in areas designated as non-attainment for O_3, PM10, and PM2.5 standards. Worst case 1-hour and 8-hour CO impacts modeling runs performed by the applicant and the SJVAPCD indicated CO emissions from the project would not cause a violation to the CO AAQS. Therefore, offset mitigation is not required for CO.

Emission offsets are used to mitigate project impacts. Offsets are reductions in emissions in one place that compensate for an increase in emissions elsewhere. Emission reduction credits (ERCs) are credits that are issued for a specific reduction in emissions that can be used as emission offsets. In the San Joaquin Valley Air Basin, ERCs are generated by voluntary reductions in emissions from stationary and area sources. ERCs can be generated from the shutdown of emission sources, adding control equipment to existing sources, or by a change in operating conditions. ERCs are issued or ‘banked’ by the District after the reductions have been analyzed to verify they are real, surplus, quantifiable, permanent and enforceable. Reductions in emissions are only eligible if the decrease in emissions can be verified and the decrease goes beyond any emissions reductions required by the District.

The SJVAPCD NSR rule, District Rule 2201, requires new facilities with emissions above certain levels to provide ERCs as mitigation. The mitigation required by the District is quantified separately from the mitigation required by the California Energy Commission. Mitigation required by SJVAPCD is outlined in the District NSR rule and does not necessary reflect the mitigation required by the California Energy Commission under CEQA. Therefore this document includes a comparison of the emission offsets quantified to satisfy the local District Rules and Regulations and with the recommendations by Energy Commission staff for additional CEQA mitigation.

The SJVAPCD NSR rule does not exactly match federal requirements in all respects; some requirements are more stringent in some areas and less stringent in others. ERCs generated in the SJVAPCD are credited as surplus at the time they are banked. However, federal requirements stipulate ERCs are to be surplus at the time of use. Because the SJVAPCD NSR rule does not require discounting of ERCs at the time of use, ERCs are tracked and adjusted on a programmatic basis. In addition, SJVAPCD offsetting thresholds are lower than federal offsetting requirements. Therefore, SJVAPCD is required to demonstrate to the U.S. EPA that on an annual basis their ERC tracking and adjustment program is equivalent to federal requirements. This demonstration includes both review of the offsets required for new and modified sources in comparison to the direct implementation of federal requirements and a review of the reductions required by SJVAPCD from new and modified sources after discounting to ensure mitigation equals or exceeds the ERCs required under federal regulations. Since SJVAPCD offsets are tracked, and adjusted if necessary on a programmatic basis, additional reasonably available control technology (RACT) adjustments are not imposed. RACT adjustments are used to reduce ERCs to account for District rules that impose emissions reductions that would have been required if the equipment were still in operation. This ensures that the emissions reductions are truly surplus to regulatory actions.

District Rule 2201 requires that the applicant provide emission offsets, in the form of banked ERCs, but only for the portion of a project’s stationary source emissions that exceed SJVAPCD Rule 2201 offset thresholds. HECA would require offsets for VOC, NOx, SO_2, and PM10 based on District Rule 2201.

District Rule 2201 does not require emissions to be offset for non-major sources of pollutants. District Rule 2201 defines the threshold for a major source of PM2.5 emissions as 100 tons per year. The project is expected to be below this threshold for PM2.5. However, the modeled impacts of PM2.5 emissions exceed the 24 hour and annual AAQS and SIL thresholds. Therefore the District is also requiring HECA to fully offset PM2.5 emissions. The District determined the full mitigation of PM2.5 emissions would not cause or make worse a violation of the PM2.5 AAQS.

Air Quality Table 26 shows the District’s summary of the emission liabilities that need to be offset.

Air Quality Table 26
HECA District Offset Calculations (lb/year)

Offset Need Determination	NOx	CO	VOC	SO_2	PM10	PM2.5
HECA Total Emissions	317,310	544,421	75,376	59,436	178,863	158,151
Offset Threshold	20,000	200,000	20,000	54,750	29,200	200,000
Offsets Triggered?	**Yes**	**Yes** [a]	**Yes**	**Yes**	**Yes**	**Yes** [b]

Source: PDOC (SJVAPCD 2013a), staff analysis.
Notes:
[a] – Although the proposed project's estimated emissions would be above the offset threshold, offset requirements for CO are exempted in attainment areas where ambient air quality standards are not violated. The project's modeling analysis provided sufficient proof to the District that CO ambient air quality standards would not be violated by this project, so CO offsets are not required.
[b] – Required because the modeled impacts of PM2.5 emissions exceed the 24 hour and annual AAQS and SIL thresholds.

The quantities of emission offsets required are calculated according to District Rule 2201 on a quarterly basis. The applicant is proposing several sources of emission reduction credits to offset the project's permitted emissions, which are described below and summarized in **Air Quality Tables 27** through **29**. Calculations of the offsets required take into consideration the distance of the project from the source of the emission reduction. This is done by the application of a distance offset ratio. For VOC and NOx from new major sources, the District requires a distance offset ratio of 1.5:1. For other pollutants the District requires a distance offset ratio of 1.3:1 for off-site ERCs created from sources that are located within 15 miles of the HECA site, and a distance offset ratio of 1.5:1 for ERCs created from sources that are located more than 15 miles from the HECA site. The applicant's proposed ERCs are from sources located more than 15 miles away, except for the VOC ERCs that come from sources located within 15 miles of the HECA project site. Therefore, a distance ratio of 1.5:1 is used for District offset purposes for all pollutants (SJVAPCD 2013a).

In addition, offsets are not required for emergency equipment that would be used exclusively as standby equipment and that would not operate more than 200 hours per year for non-emergency purposes such as testing and maintenance. Therefore emissions from the two emergency engines and emergency fire pump are subtracted from the facility total emissions prior to the application of the distance offset ratio in the offset determination calculations.

The applicant is proposing to satisfy their offset requirements for both PM10 and PM2.5 through interpollutant offsets. The use of interpollutant offsets is approved by the District on a case by case basis. Approval is based on a demonstration that the emission increases would not cause or contribute to a violation of an AAQS. Per District Rule 2201, interpollutant offsets between PM2.5 and PM2.5 precursors are allowed at specific ratios established by U.S. EPA or as approved in the SIP. The District approved a 1:1 interpollutant ratio of SOx offsets for PM10/PM2.5. This ratio is based on chemical mass balance modeling and speciated rollback modeling performed for the 2008 PM2.5 attainment plan.

As shown in **Air Quality Table 27** through **Air Quality Table 30**, the applicant has demonstrated, per District requirements and Energy Commission policy, that it owns ERCs in quantities sufficient to offset the project's NOx, VOC, SO_2 and PM10 emissions.

NOx Emission Offsets

Air Quality Table 27 provides a summary of the total project NOx emissions subject to District offsets and identifies the offset emission reduction credit sources owned by the applicant. Credit S-3273-2 was created in November 1983 from the shutdown of a catalytic cracker, fluid coker, and CO boiler. Credits C-1058-2 were created in January 2008 through the installation of a SCR unit, a scrubber, and a conversion from fuel oil to natural gas.

Air Quality Table 27
NOx Offsets Available for HECA

Offset Source Location	Distance (miles)	Credit Number	Total Q1 (lb)	Total Q2 (lb)	Total Q3 (lb)	Total Q4 (lb)
Emissions Above Threshold [a]		---	74,201	74,201	74,201	74,201
6500 Refinery Ave., Bakersfield	> 15	S-3273-2	120,500	120,500	120,500	120,500
11535 E. Mountain Ave., Kingsburg	> 15	C-1058-2	10,100	10,100	10,100	10,100
Total ERC Holdings		---	130,600	130,600	130,600	130,600
Total HECA Offsets required @ 1.5:1		---	111,302	111,302	111,302	111,302
Surplus		---	19,299	19,299	19,299	19,299

Sources: PDOC (SJVAPCD 2013).
Note: [a] – The offset emission thresholds are provided in **Air Quality Table 26**, and the quarterly threshold is one quarter of the annual threshold shown in that table after subtracting the emergency equipment emissions provided in **Air Quality Table 17**.

The applicant has sufficient offset credits to comply with the District's NOx offset requirements for this project. The applicant could retain or sell the surplus ERCs they own that are not needed to offset this project.

VOC Emission Offsets

Air Quality Table 28 provides a summary of the total project VOC emissions subject to District offsets and identifies the offset emission reduction credit sources owned by the applicant. Credits S-3305-1, S-3557-1 and S-3605-1 are all from the same emission reduction event that occurred in September 1979 through the shutdown of an entire stationary source. The applicant is proposing to surrender ERC certificate S-3305-1 and a portion of S-3605-1 to offset the VOC emissions from the project.

The applicant has sufficient offset credits to comply with the District's VOC offset requirements for this project. The applicant could retain or sell the surplus ERCs they own that are not needed to offset this project.

SOx and PM10/PM2.5 Emission Offsets

The applicant has proposed the use of SOx emissions offsets to mitigate PM10 and PM2.5 emissions as a form of interpollutant offsets to complete the PM10 offset package. **Air Quality Table 29** provides a summary of the total project SO_2 and PM10 emissions subject to District offsets and identifies the offset emission reduction credit sources owned by the applicant. Credit S-3275-5 was created in March of 1992 through the shutdown of a tail gas incinerator. Credit C-1058-5 was created in January 2008 through the installation of a scrubber and a conversion from fuel oil to natural gas.

Air Quality Table 28
VOC Offsets Available for HECA

Offset Source Location	Distance (miles)	Credit Number	Total Q1 (lb)	Total Q2 (lb)	Total Q3 (lb)	Total Q4 (lb)
Emissions Above Threshold [a]		---	13,792	13,792	13,792	13,792
20807 Stockdale Hwy, Bakersfield	< 15	S-3305-1	14,625	14,625	14,625	14,625
20807 Stockdale Hwy, Bakersfield	< 15	S-3557-1	11,437	11,438	11,438	11,437
20807 Stockdale Hwy, Bakersfield	< 15	S-3605-1	7,937	7,938	7,938	7,937
Total ERC Holdings		---	33,999	34,001	34,001	33,999
Total HECA Offsets required @ 1.5:1 [b]		---	20,688	20,688	20,688	20,688
Surplus		---	13,311	13,313	13,313	13,311

Sources: PDOC (SJVAPCD 2013a).
Note: [a] – The offset emission thresholds are provided in **Air Quality Table 26**, and the quarterly threshold is one quarter of the annual threshold shown in that table after subtracting the emergency equipment emissions provided in **Air Quality Table 17**.
Note: [b] – The offset ratio required per SJVAPCD Rule 2201, Section 4.8.1.

Air Quality Table 29
SOx and PM10/PM2.5 Offsets Available for HECA

Offset Source Location	Distance (miles)	Credit Number	Total Q1 (lb)	Total Q2 (lb)	Total Q3 (lb)	Total Q4 (lb)
SOx Emissions Above Threshold [a]		---	1,170	1,170	1,170	1,170
PM10 Emissions Above Threshold [a]		---	37,404	37,404	37,404	37,404
PM2.5 Emissions			39,538	39,538	39,538	39,538
6451 Rosedale Hwy, Bakersfield	> 15	S-3275-5	42,000	42,000	42,000	42,000
11535 E. Mountain Ave., Kingsburg	> 15	C-1058-5	24,500	24,500	24,500	24,500
Total ERC Holdings		---	66,500	66,500	66,500	66,500
Total HECA SOx Offsets required @ 1.5:1		---	1,755	1,755	1,755	1,755
Total HECA PM10 Offsets required @ 1.5:1		---	56,106	56,106	56,106	56,106
Total HECA PM2.5 Offsets required @ 1.5:1			59,307	59,307	59,307	59,307
Total HECA Offsets required [b]		---	61,062	61,062	61,062	61,062
Surplus		---	5,438	5,438	5,438	5,438

Sources: PDOC (SJVAPCD 2013a).
Notes:
[a] – The offset emission thresholds are provided in **Air Quality Table 26**, and the quarterly threshold is one quarter of the annual threshold shown in that table after subtracting the emergency equipment emissions provided in **Air Quality Table 17**.
[b] – Total offsets include the SOx offsets and PM2.5 offsets. The PM10 offsets required include PM2.5 emission. However, since the facility is fully offsetting the PM2.5 emissions they exceed the PM10 offset contribution.

The applicant has proposed the use of SOx for PM10 interpollutant offsets. SOx is accepted as one of the major precursors of PM10 and PM2.5 through reaction with ammonia to form ammonium sulfates. Reductions in SOx, particularly in areas that are ammonia rich such as the SJVAB, will reduce secondary particulate formation. Therefore, interpollutant offsets of SOx for PM10 can be used to reach the goal of mitigating a project's impacts to regional ambient particulate concentrations. The key issue is the determination of an appropriate interpollutant offset ratio, which depends on the existing levels of PM precursors and the general air chemistry of the area in question. The District has determined that an offset ratio of 1:1 is adequate for SOx for

PM10 interpollutant ERC trading. However, the SJVAPCD's Governing Board approved the District's 2012 PM2.5 Plan for inclusion in the State Implementation Plan (SIP) in December 2012, which was then approved by the California Air Resources Board (ARB) on January 24, 2013. That plan calls for a 4.1 to 1 sulfur oxides (SOx) for PM2.5 interpollutant offset ratio for the San Joaquin Valley, and use of the 1:1 offset ratio was rejected by the U. S. EPA. Additionally, there is no reason that the SOx for PM2.5 interpollutant offset ratio should be different than the SOx for PM10 interpollutant offset ratio. However, both the applicant and SJVAPCD are still using a 1:1 SOx for PM interpollutant offset ratio. Staff has provided a comment to the District regarding the appropriateness of this offset ratio and the Final Staff Assessment (FSA) will provide additional information based on the comment response provided by the District in the FDOC.

The applicant does not currently have sufficient offset credits to comply with the District's SOx and PM10 offset requirements for this project if the SOx to PM10 offset ratio is increased from 1:1 to 4.1:1.

CEQA Offsets

Energy Commission staff have long held that for fossil fuel power plants, the annual operation emissions for all nonattainment pollutants and their precursors need to be fully offset at a minimum 1:1 ratio, not just the portion of a facility's emissions that exceed offset trigger levels, such as allowed by SJVAPCD Rule 2201. For this project, as shown in **Air Quality Table 30**, the District's offset requirements would exceed that minimum 1:1 offsetting goal for NOx, VOC, SOx, PM10 and PM2.5.

Air Quality Table 30
Total Operations Offset Ratio for HECA's SJVAB Emissions

Pollutant	Annual Emissions[a]	District Required ERCs	Offset Ratio
NOx	317,310 lbs/year	445,206 lbs/year	1.40:1
VOC	75,379 lbs/year	82,672 lbs/year	1.10:1
SOx + PM10/PM2.5[b]	238,299 lbs/year	244,248 lbs/year [c]	1.02:1

Source: Compilation of data from **Air Quality Tables 17**, and **27** through **29**
Notes:
[a] **– Total facility emissions, not just the portion that exceeds Rule 2201 thresholds**
[b] – PM10/PM2.5 offset requirements are the larger of the two. In this case PM2.5.
[c] – SO_2 ERCs.

Staff notes that with the assumption that an interpollutant offset ratio of SOx for PM[13] of 1:1 is appropriate, the applicant's offset proposal would meet staff's CEQA offset recommendation of a minimum offset threshold of 1:1 for all non-attainment pollutants and their precursors. However, if a SOx for PM interpollutant offset ratio of 4.1:1 is determined to be appropriate then the applicant does not currently have enough SOx credits to offset the combined HECA SOx and PM emissions. The final evaluation of the adequacy of this interpollutant offset ratio will in part be based on the District's response to staff's questions on this issue. Staff will determine, based on that response and the rest of the evidence provided, whether recommended adjustments need to be made to

[13] Staff evaluation of CEQA mitigation for PM2.5 impacts is the same as for PM10.

this interpollutant offset ratio for CEQA mitigation purposes. Staff will provide this final determination in the FSA/FEIS.

Mitigation Agreements

The applicant has entered into two separate Governing Board approved mitigation agreements with the District. The first agreement covers providing VOC and NOx emissions reductions for General Conformity compliance and additional PM10 emissions reductions for District CEQA compliance purposes. This agreement covers providing emission reduction funding of over $7,500,000 to address 243.6 tons of NOx, 39.5 tons of VOC, and 61.3 tons of PM10 emissions during project construction and ten years of project operating NOx transportation emissions, totaling 436 tons of NOx emissions (SJVAPCD 2013c, Attachment A, Exhibit C). The monies obtained by this agreement would be used by the District to fund emissions reductions within the air basin. However, the applicant would be required to provide additional funding or emission reduction credits from the District bank to cover any shortages in the emission reductions obtained versus the amount of necessary emissions reductions identified in this agreement until sum of the emissions reductions obtained equals the amount of emission reductions required by this agreement.

The second voluntary emissions reduction agreement (VERA) addresses excess NOx emissions from the project due to the fact that the NOx emissions efficiency for this project is lower than for natural gas fired combined cycle projects. The District has determined that this lower efficiency results in an additional 16.7 tons per year of NOx emissions as compared with other combined cycle projects and requires the fee for this agreement to be based on the current average NOx ERC cost of $67,492 per ton. The total amount required to be paid to the District under this voluntary agreement, including a 5 percent administrative fee, is $1,181,135. Unlike the other mitigation agreement, this is a one-time fee that has no stipulations in regards to the final amount of emissions reductions achieved by the emissions reduction projects funded with the monies obtained from this agreement.

Staff recognizes that the first agreement would be used to satisfy General Conformity offset requirements, and is subject to approval by DOE. Additionally, staff recognizes the additional air quality benefits that the first agreement and the second voluntary agreement would provide, including the associated reduction of pollutants (PM10, PM2.5, air toxic pollutants), other than VOC and NOx. Staff supports the applicant and the District in their efforts to provide these additional air quality benefits to the region. However, staff would prefer that these agreements include an additional implementation requirement that these emission reductions would occur as close to the project site as feasible.

Adequacy of Proposed Mitigation

Staff concurs with the District's determination that the project's proposed emission controls/emission levels for criteria pollutants meets BACT requirements and that the proposed emission levels are reduced to the lowest technically feasible levels.

Staff has made a preliminary determination that the applicant's offset proposal meets both District requirements and meets CEQA mitigation requirements for the project's stationary sources. Additionally, staff agrees with most of the mitigation measures that the applicant has proposed to reduce emissions from the project's mobile sources that are not regulated by the District. However, there are two issues that need to be resolved prior to the issuance of the FSA in order for staff to finalize this determination. These two issues are as follows:

1) SO_2-for-PM10 offset ratio.

Staff is still evaluating the appropriateness of the 1:1 offset ratio for interpollutant trading of SO_2 for PM10 in terms of providing adequate and SIP-required mitigation for the project's potential PM10 impacts and adequate mitigation for the project's PM2.5 impacts. Staff and U.S. EPA have previously provided comments regarding this issue to the District (CEC 2010, U.S. EPA 2010), and staff has provided another comment on this issue in staff's PDOC comment letter to the SJVAPCD, dated March 28, 2013. Staff will be evaluating the District's response and additional comments from other parties, such as U.S. EPA, as part of our final conclusion regarding this issue.

2) Mercury and Air Toxics Standards (MATS) Compliance

The District has not included any MATS compliance conditions in the PDOC. Staff acknowledges that the MATS regulation has been stayed but U.S. EPA published the amended MATS rule on March 28, 2013. Therefore, the District should assume that by the time the project begins operation, the MATS regulation will be in force and provide necessary permit conditions for MATS rule compliance. The affected sources are the combustion turbine generator/heat recovery steam generator (CTG/HRSG) and coal dryer that need to meet the particulate, mercury, and hydrogen chloride emission limitations of this rule. For the time being, staff has added Condition of Certification **AQ-SC13** to address the project's MATS compliance requirements.

Additionally, in the March 28, 2013 letter to SJVAPCD, staff has provided several other comments to the District on the PDOC that staff feels need to be resolved for clarity of the analysis findings and the permit condition requirements.

Staff Proposed Mitigation

Staff is proposing several staff conditions of certification (**AQ-SC6** through **AQ-SC14**), some of which memorialize mitigation commitments made by the applicant for mobile source emissions, and others to fill gaps in the emissions mitigation proposed by the applicant and the District in the PDOC.

To reduce the project's on-road and off-road emissions, staff is proposing Conditions of Certification **AQ-SC6** and **AQ-SC7**. Condition of Certification **AQ-SC6** requires that when the applicant purchases vehicles for feedstock (coal and petcoke) transport during facility operations, they must purchase new model year dedicated on-road and off-road equipment. This will reduce potential operating period maintenance and on-site fuel handling emissions by ensuring that only new equipment meeting the latest emissions standards are purchased. Staff Condition of Certification **AQ-SC7** requires that when the applicant contracts out for these services, the contractor must use vehicles with engines that meet post-2010 emissions standards.

Due to the large project site, much of which will not be paved or otherwise controlled, staff is proposing Condition of Certification **AQ-SC9** that would require the applicant provide and implement a fugitive dust control plan during operations.

In response to concerns regarding fugitive particulate emissions and spillage from the transport of coal, the applicant has agreed to either use covered railcars or dust suppressants to control the fugitive dust from rail based coal transportation. Therefore, staff has included Condition of Certification **AQ-SC10** to memorialize this applicant stipulation and has expanded it to include the control of fugitive dust emission from all transported bulk materials to and from the site. This condition of certification also includes right of way inspection requirements along the transportation routes to ensure mitigation measure effectiveness (i.e. no observed spillage). For the rail transportation this is currently limited to the length of the HECA rail spur for several reasons, including; right of access to the right of way, and issues of attribution where rail transport of coal would include other end users. Staff will consider increasing the inspection requirements if access and spillage source attribution can be assured.

To reduce air pollutant emissions from rail transportation, staff is proposing Condition of Certification **AQ-SC12**. This condition memorializes the applicant's proposed measure to require the contracted rail provider to use Tier 3 or better locomotives. However, given the fact that Tier 4 standards will be in effect for new locomotive and switching engines by 2015, which would be before the project could start operation if approved, staff is proposing that the applicant obtain an onsite switching engine that meets Tier 4 standards, and that the applicant require the contracted rail provider to use Tier 4 locomotives starting in 2020. The difference between Tier 3 and Tier 4 standards, as opposed to the difference between Tier 2 and Tier 3 standards, is substantial for NOx and PM emissions, so staff believes that requiring the project to use locomotive and switching engines that meet this higher engine Tier standard is a feasible measure that would provide a significant reduction of the project's long-term transportation emissions.

As noted above, staff has included Condition of Certification **AQ-SC13** to address compliance with the federal MATS regulation. Staff expects to delete this condition assuming the District, per staff's comment on the PDOC, adds MATS compliance conditions in the FDOC.

Staff condition **AQ-SC14** is included to ensure that the two mitigation agreements the applicant has signed with the District are being complied with, specifically that the required funding has been provided in a timely manner in compliance with these two agreements.

Staff is also proposing conditions of certification (**AQ-SC11** and **AQ-SC8)** that would ensure that the license is amended as necessary to incorporate changes to the air quality permits and ensure ongoing compliance through the requirement of quarterly operations reports that demonstrate compliance, respectively.

Staff has considered the environmental justice population surrounding the site (see **Socioeconomics Figure 1**). Since the project's direct air quality impacts have been reduced to less than significant, there is no environmental justice issue for air quality.

Chemically Reactive Pollutant Impacts

The project's gaseous emissions of NOx, SO_2, VOC and ammonia can contribute to the formation of secondary pollutants: ozone and PM10/PM2.5.

Ozone Impacts

There are air dispersion models that can be used to quantify ozone impacts, but they are used for regional planning efforts where hundreds or even thousands of sources are input into the modeling to determine ozone impacts to large regions such as air basins. There are no regulatory agency models approved for assessing single source ozone precursor impacts. However, because of the known relationship of NOx and VOC emissions to ozone formation, it can be said that the emissions of NOx and VOC from HECA do have the potential (if left unmitigated) to contribute to higher ozone levels in the region. These impacts would be cumulatively significant because they would contribute to ongoing violations of the state and federal ozone ambient air quality standards as shown in **Air Quality Figure 1**, provided on page 4.1-17. Staff is recommending Condition of Certification **AQ-SC5** to reduce the NOx and VOC emissions from off-road equipment during construction. The District rules require that the NOx and VOC emissions for HECA be offset at a greater than 1:1 ratio (provided in District conditions **AQ-1**). Staff concludes that with these mitigation measures the project's ozone impacts are less than significant.

Secondary PM10/PM2.5 Impacts

Secondary PM10 formation, which is assumed to be 100 percent PM2.5, is the process of conversion from gaseous reactants to particulate products. The process of gas-to-particulate conversion, which occurs downwind from the point of emission, is complex and depends on many factors, including local humidity and the presence of air pollutants. The basic process assumes that the SOx and NOx emissions are converted into sulfuric acid and nitric acid first, and then react with ambient ammonia to form sulfate and nitrate. The sulfuric acid reacts with ammonia much faster than nitric acid and converts completely and irreversibly to particulate form. Nitric acid reacts with ammonia to form both a particulate and a gas phase of ammonium nitrate. The particulate phase will tend to fall out. However the gas phase can revert back to ammonia and nitric acid. Thus, under the right conditions, ammonium nitrate and nitric acid establish a balance of concentrations in the ambient air. There are two conditions that are of interest, described as "ammonia rich" and "ammonia poor." The term "ammonia rich" indicates that there is more than enough ammonia to react with all the sulfuric acid and to establish a balance of nitric acid-ammonium nitrate. Further ammonia emissions in this case would not necessarily lead to proportional increases in ambient PM2.5 concentrations. In the case of an "ammonia poor" environment, there is an insufficient amount of ammonia to establish a balance and thus additional ammonia would tend to increase PM2.5 concentrations.

The San Joaquin Valley has been the subject of an extensive secondary particulate formation study, the California Regional Particulate Air Quality Study, which has determined that the San Joaquin Valley is ammonia rich. Therefore, the ammonia emissions from HECA are not expected to lead to substantial further formation of ammonium nitrate or sulfate. While there would certainly be some conversion from the ammonia emitted from HECA, there is currently no regulatory model that can predict the conversion rate. Additionally, VOC emissions have the potential to convert into organic particles, where depending on the location the primary concern related to secondary PM2.5 formation from VOC is biogenic rather than anthropogenic (i.e. from natural organic releases such as turpene emissions from pine trees). However, because of the known relationship of NOx, SOx, and VOC emissions to PM2.5 formation, it can be said that the emissions of these three pollutants from HECA do have the potential (if left unmitigated) to contribute to higher PM2.5 levels in the region.

The applicant is proposing to mitigate the project's NOx, VOC, SO_2, and PM10 emissions through the use of emission offsets and limit the ammonia slip emissions to 5 ppm for the CTG/HRSG and 10 ppm for the nitric acid plant. The NOx, VOC, SO_2, and PM10 offsets are proposed by the applicant to be provided for emissions above the District offset thresholds at an offset ratio that is greater than 1 to 1, meaning offsetting with emissions reductions that are greater than the emissions increases. Additionally, the applicant has agreed to create additional emissions reductions by funding the District's Emission Reduction Incentive Program (ERIP). Staff does have questions regarding the appropriate SOx for PM interpollutant offset ratio; however, with the proposed emission offsets and additional mitigation funding, staff concludes at this time that the project would not cause significant secondary PM2.5 pollutant impacts.

DIRECT/INDIRECT IMPACTS AND MITIGATION – EOR COMPONENT

Based on the information currently available for the OEHI CO_2 EOR component, this section examines the potential air quality impacts of the OEHI CO_2 EOR component that would use HECA's separated CO_2 for tertiary oil recovery. The EOR component includes the construction of the CO_2 pipeline, the drilling of CO_2 injection wells, the construction of the CO_2 injection system and the CO_2 recovery and recycling systems. This project component is expected to be subject to the completion of a separate EIR, and if so would be required to mitigate emissions as determined to be required under CEQA by that separate environmental analysis.

The air quality impacts of this related project would include short-term construction impacts that would occur during the same timeframe as the HECA construction (see **Air Quality Table 18** for a summary of the estimated OEHI CO_2 EOR component's construction emissions); and operating impacts related to this EOR component would include stationary source emissions from the new oil recovery and CO_2 recycling systems and indirect emissions from the additional electrical energy needed for the CO_2 compressors and other electrical requirements to operate the EOR system (see **Air Quality Table 19** for a summary of the estimated OEHI CO_2 EOR component's operating emissions). However, if CO_2 were not being made available from HECA then it is possible that OEHI would use other tertiary oil recovery methods, such as water or other gas injection, to recover crude oil that could be recovered with these methods and these other tertiary oil recover methods could have operating emissions as high as or higher than the proposed CO_2 based EOR system.

Staff's initial findings regarding this project-related action are as follow:

- The construction related impacts of this EOR component would generally occur several miles from HECA, and construction emissions mitigation would be required as part of that project's CEQA/NEPA process. Staff believes that with adequate mitigation, the combined construction impacts of HECA and the EOR component would be less than significant.

- The direct operating stationary source emissions of the EOR component would require appropriate permitting from the SJVAPCD, with emission reduction mitigation as required under District Rules (such as BACT and offsets, if necessary). Therefore, staff believes that the cumulative operation impacts of HECA and the EOR component would be less than significant.

In addition, staff makes the following inter-agency request to ensure that the cumulative air quality impacts of these two projects are less than significant:

- The Energy Commission requests that the EOR component CEQA/NEPA responsible agency require construction emission mitigation measures that are as strict or stricter than the measures provided in Staff Conditions **AQ-SC3** and **AQ-SC5**.

CUMULATIVE IMPACTS

"Cumulative impacts" are defined as "two or more individual effects which, when considered together, are considerable or…compound or increase other environmental impacts." (CEQA Guidelines, § 15355.) A cumulative impact consists of an impact that is created as a result of a combination of the project evaluated in the EIR together with other projects causing related impacts." (CEQA Guidelines, § 15130(a)(1).) Such impacts may be relatively minor and incremental, yet still be significant because of the existing environmental background, particularly when one considers other closely related past, present, and reasonably foreseeable future projects.

This analysis is concerned with criteria air pollutants. Such pollutants have impacts that are usually (although not always) cumulative by nature. Rarely would a project by itself cause a violation of a federal or state criteria pollutant standard. However, a new source of pollution may contribute to violations of criteria pollutant standards because of the existing background sources or when combined with foreseeable future projects. Air districts attempt to attain the criteria pollutant standards by adopting attainment plans, which comprise a multi-faceted programmatic approach to such attainment. Depending on the air district, these plans typically include requirements for air emissions offsets and the use of Best Available Control Technology (BACT) for new sources of emissions, and restrictions of emissions from existing sources of air pollution.

Thus, much of the preceding discussion is concerned with cumulative impacts. The "Existing Ambient Air Quality" section describes the air quality background in the San Joaquin Valley Air Basin in the vicinity of the proposed project's site, including a discussion of historic ambient levels for each of the significant criteria pollutants. The "Construction Impacts and Mitigation" subsection discusses the project's contribution to the local existing background caused by project construction. The "Operation Impacts and Mitigation" section discusses the proposed project's contribution to the local existing background caused by project operation. The following subsection includes these additional analyses:

- a summary of projections for criteria pollutants by the air district and the air district's programmatic efforts to abate such pollution; and
- an analysis of the proposed project's *localized cumulative impacts*, the proposed project's direct operating emissions combined with other local major emission sources;

Summary of Projections

The SJVAPCD is the lead agency for managing air quality and coordinating planning efforts for the portion of Kern County within the SJVAB, so that the ozone and PM10 standards are attained in a timely fashion and attainment with CO standards are maintained[14]. The District is responsible for developing those portions of the State Implementation Plan (SIP) and the Air Quality Management Plan (AQMP) that deal with certain stationary and area source controls and, in cooperation with the transportation planning agencies (TPAs), the development of transportation control measures (TCMs). In this role the SJVAPCD is the agency with principal responsibility for analyzing and addressing cumulative air quality impacts, including the impacts of ambient ozone and particulate matter. The District has summarized the cumulative impacts of ozone and particulate matter on the air basin from the broad variety of its sources. Analyses of these cumulative impacts, as well as the measures the District proposes to reduce impacts to air quality and public health, are summarized in four publicly available documents that the District has adopted. These adopted air quality plans are summarized below.

2007 Ozone Plan (8-hour ozone plan)
Link: http://www.valleyair.org/Air_Quality_Plans/AQ_Final_Adopted_Ozone2007.htm

Extreme Ozone Attainment Demonstration Plan (1-hour ozone plan)
Link: http://www.valleyair.org/Air_Quality_Plans/AQ_plans_Ozone_Final.htm

Reasonably Available Control Technology (RACT) Demonstration for Ozone State Implementation Plans (SIP)
Link: http://www.valleyair.org/Air_Quality_Plans/docs/RACTSIP-2009.pdf

2007 PM10 Maintenance Plan
Link: http://www.arb.ca.gov/planning/sip/sjvpm07/sjvpm07.htm

2008 PM2.5 Plan
Link:http://www.valleyair.org/Air_Quality_Plans/AQ_Final_Adopted_PM25_2008.htm

2012 PM2.5 Plan
Link: http://www.valleyair.org/Air_Quality_Plans/PM25Plans2012.htm

The Extreme Ozone Attainment Demonstration Plan for 1-hour ozone was approved by the U.S. EPA on March 8, 2010. The 2007 Ozone Plan for 8-hour ozone, attainment planning for the 1997 8-hour ozone standard, was adopted by the District on April 30,

[14] The project area is in a CO attainment area that is not a maintenance area, so the SJVAPCD CO Maintenance Plan is not applicable to the project area and CO planning will not be discussed further.

2010 and by the ARB on June 14, 2010. U.S. EPA approved the 8-hour ozone plan in December 2011. The U.S. EPA approval of the Extreme Ozone Attainment Demonstration Plan was subsequently withdrawn in November 2012, along with partially withdrawing approval of the 2007 ozone plan. The District is developing a new 1-hour ozone plan which it plans on submitting by June 2013. Additionally, the District is expecting to submit an 8-hour ozone plan by 2015 to address the current extreme non-attainment of the 2008 8-hour ozone standard.

A reasonably available control technology (RACT) demonstration for ozone is required by U.S. EPA to demonstrate that the District has satisfied all federal RACT requirements as necessary for NAAQS attainment planning purposes. The District's 2009 RACT demonstration document found that the current District rules, with two minor exceptions, meet the federal RACT requirements. One of those rules, Rule 4311 – Flares, applies to this project. The District subsequently amended Rule 4311 in 2009 to comply with the federal RACT requirement, and this project must comply with that amended rule and all of the other applicable District rules that comply with the federal RACT requirements.

The 2007 PM10 Maintenance Plan was approved and the SJVAB was redesignated as attainment for PM10 by U.S. EPA on September 2008. The 2008 PM2.5 Plan was adopted by the District on April 30, 2008 and was submitted to the U.S. EPA by ARB on June 30, 2008. U.S. EPA approved nearly all elements of the 2008 PM2.5 Plan in September, 2011. The 2012 PM2.5 Plan was adopted by the District in December 2012 and approved by ARB on January 24, 2013. Since the plan has not yet been approved by U.S. EPA, the 2008 PM2.5 Plan is the currently approved plan.

Ozone

Extreme Ozone Attainment Demonstration Plan and 2007 Ozone Plan

The 2007 Ozone Plan, like the 1-hour Extreme Ozone Plan, requested that the SJVAB be reclassified as an extreme nonattainment area, which was granted by U.S. EPA. The extreme designation will change permitting requirements and definitions; including lowering the emissions threshold for determining whether or not a proposed facility is a major source and increasing the minimum offset ratio to 1.5 to 1 assuming that the District cannot prove all major sources have implemented BACT, a requirement that has been added to Rule 2201.[15] Other requirements include the expeditious implementation of reasonably available control technology (RACT). The plan includes a number of control measures to implement the reductions needed for attainment and these include stationary source control measures, as well as incentive measures, innovative measures, and the implementation of other transportation and engine standard measures for state and federal government fleet vehicles. These plans target NOx and VOC emission reductions from a multitude of stationary source types, such as wineries, feedlots, small combustion sources, gas turbines, IC engines, and various solvent/coating sources. However, the plan would not impact the HECA emission sources because they already meet BACT requirements.

[15] However, this Rule 2201 requirement, as provided in Section 4.8.1, does not apply to HECA as the project's original permit application was deemed complete before this rule update became effective.

Compliance with Ozone Plans

The SJVAPCD rules and regulations specify performance standards, offset requirements, and emission control requirements for stationary sources. The regulations also include requirements for obtaining Authority to Construct (ATC) permits and subsequent operating permits. These regulations apply to HECA and all other projects with emission sources. In general, triennial updates of the attainment plans ensure that population, employment, and transportation trends in the region are taken into account, and compliance with SJVAPCD rules and regulations ensures consistency with the regional air quality management plans.

Energy Commission staff has evaluated a potential concern that HECA could interfere with the attainment effort of the 2007 Ozone Plan if it relies on offsets created by emission reductions prior to the plan baseline. The SJVAPCD is expecting new stationary sources like HECA to use pre-baseline credits (pre-2002 for the 2007 Ozone Plan) to allow growth from permitted stationary sources during the period of this plan, but as a safeguard, a cap would be established on the quantity of pre-baseline credits used by new sources. Additionally, the integrity of the proposed mitigation may be adversely affected by the annual equivalency demonstration required by SJVAPCD Rule 2201, Section 7, which ensures that the District's offset requirements are at least as stringent as the federal requirements. Since the project's FDOC is expected to be issued before there is any failure in the equivalency demonstration, the ERCs used for HECA need not be "surplus at time of use". The implication is that the ERCs surrendered for HECA are presently surplus and they would not be subject to discounting to demonstrate equivalency with federal offset requirements. The project could result in future failures in the annual NSR offset equivalency demonstration, which would impact how future project ERC sources are evaluated, but that would not directly impact the offset compliance status for HECA. Therefore, because the project would use BACT to control ozone precursor emissions and ERCs at a minimum offset ratio of 1.5 to 1 (for NOx and VOC) to fully offset ozone precursors as required by the effective version of New Source Review Rule 2201 at the time the project's application was deemed complete by the District, staff has determined that the project would not directly conflict with the District's 2007 Ozone Plan or regional ozone attainment goals.

Particulate Matter

2007 PM10 Maintenance Plan

The 2007 PM10 Maintenance Plan illustrates how the SJVAPCD intends to continue the efforts of the 2003 PM10 Plan and 2006 PM10 Plan that implemented aggressive PM10 controls in the region, including Reasonably Available Control Measures (RACM) for large existing sources of PM10 and fugitive dust. The 2007 PM10 Maintenance Plan includes a request for reclassification to "attainment" for the federal PM10 standard, and it provides for continued attainment for 10 years from the designation. In November 2008, the U.S. EPA redesignated the SJVAPCD to attainment for the federal PM10 standard (73 FR 66759, November 12, 2008).

2008 PM2.5 Plan

The District prepared a 2008 PM2.5 Plan which focuses primarily on the strategy to attain the 1997 annual standard set by the U.S. EPA of 65 $\mu g/m^3$ by 2015. In 2006, U.S.

EPA revised the 24-hour standard to 35 μg/m^3. Through continued implementation of the 2008 PM2.5 Plan the SJVAB is predicted to be in attainment of the 1997 annual standard by 2015.The section below discusses attainment with the revised standard.

The 2008 PM2.5 Plan contains a comprehensive list of strict regulatory and incentive-based measures to reduce directly emitted PM2.5 and precursor emissions throughout the San Joaquin Valley. The plan considers all of the following four facets of control strategy:

- Regulatory Control Measures for Stationary Sources,
- Incentive-based Strategies,
- Innovative Strategies and Programs, and
- Local, State, and Federal Sources/Partnerships

2012 PM2.5 Plan

The District prepared a 2012 PM2.5 Plan which focuses primarily on the strategy to attain the 2006 annual standard set by the U.S. EPA of 35 μg/m^3 by 2019. It is expected the majority of the Valley will be in attainment prior to the 2019 deadline. ARB approved the plan at a public hearing on January 24, 2013.

The 2012 PM2.5 Plan builds on existing strategies to reduce PM2.5 emissions. The plan incorporates local, state and federal strategies to reduce PM2.5 emissions. The strategies involve targeting both direct PM 2.5 and indirect PM 2.5 through reducing NOx emissions. NOx emissions are identified as the predominate pollutant leading to the formation of PM2.5, they are expected to be reduced by 55 percent. Focusing on NOx reductions has the added benefit of assisting with strategies aimed at reducing ozone. A critical component to the plan involves the reduction of mobile source emissions. The reduction of mobile source emissions is dependent on state and federal measures.

The 2012 plan includes the following control strategies:

- Wide-ranging regulations for both stationary sources and the public,
- Risk based approach prioritizing measures for expeditious attainment considering public health benefits,
- Incentive programs targeting mobile sources including off-road vehicles and equipment,
- Research/further studies to continue to develop policies and identify additional clean air strategies,
- Policy and legislative efforts at local state and federal levels,
- Outreach efforts to assist the public in getting involved to improve air quality,
- State and federal regulations reducing emissions from mobile sources including on-road and off-road sources,

- Incentive funding and programs to assist the District in reducing mobile source emissions, and
- Technology advancement efforts including funding and collaborative support from other agencies to develop new zero and near zero-emission technologies.

Compliance with Particulate Plans

Energy Commission staff is concerned that HECA could interfere with the attainment effort of the 2008 PM2.5 Plan if it relies on SOx emission reduction credits without an adequate interpollutant trading ratio for PM2.5 increases. The "reasonable further progress" calculations in the 2008 PM2.5 Plan shows that about ten times more tons of direct PM2.5 need to be reduced than SO_2 (Table 8-2 of 2008 PM2.5 Plan). The 2014 Receptor Modeling Documentation supporting the 2008 PM2.5 Plan indicates that reducing SOx would not be as effective as reducing direct PM2.5 as NOx. The District inventory of SOx is too small to have enough of an impact when compared to direct PM2.5 or NOx. Interpollutant trading is allowed with "the appropriate scientific demonstration of an adequate trading ratio" (Rule 2201, Section 4.13), and the SJVAPCD 2007 PM10 Maintenance Plan (see Appendix E of the Maintenance Plan) indicates that the minimum ratio would be one-to-one with higher interpollutant ratios if appropriate under Rule 2201. The PDOC indicates that the approved interpollutant offset ratio for SOx for PM10 for HECA is 1 to 1. However, staff notes that although implementation of trading under District Rule 2201 is subject to federal oversight, there is no evidence in the record indicating whether the methods used by the District in developing the interpollutant SOx for PM10 ratio has been specifically reviewed and/or approved by U.S. EPA.

Additionally, there are issues regarding the PM2.5 emission estimate for the project that have been previously commented on by Energy Commission staff (CEC 2010) and U.S EPA (U.S. EPA 2010). However, staff believes that the PM2.5 emissions, with the current operations assumptions would not exceed the Clean Air Act New Source Review trigger of 100 tons per year which would mean that the PM2.5 offsets do not have to comply with an interpollutant precursor trading ratio approved by U.S. EPA.

Although there is no formal federal endorsement of the District's interpollutant trading approach for PM10, Energy Commission staff preliminarily concludes that HECA would not conflict with regional particulate matter attainment and maintenance goals due to the following reasons and assumptions:

- The project is required to apply a distance ratio to the emission reduction credits that increases the overall offset ratio for PM10 to 1.5 to 1.
- Staff recognizes that the PM2.5 attainment plan has been previously adopted by ARB, and the SJVAPCD has determined that the interpollutant trading ratio for HECA is appropriate.
- The PDOC shows that HECA is likely to comply with the particulate matter plans by meeting its permit requirements and complying with the existing applicable rules and regulations.
- Offsets do not provide for future reductions in emissions impacts, rather they have provided past reductions and benefitted the air basin since the time of the reduction;

and a review of the SJVAB historical emissions inventories and PM2.5 ambient concentrations seems to indicate that the improvements in PM2.5 ambient concentrations may to some extent track with the reductions in SO_2 emissions that have occurred in the SJVAB over the past 15 years.

Staff may revise this preliminary conclusion if further analysis shows that the one-to-one SO_2 for PM offset ratio would significantly interfere with the attainment effort of the 2008 PM2.5 Plan.

Localized Cumulative Impacts

Since power plant direct air quality impacts can be reasonably estimated through air dispersion modeling (see the "Operation Modeling Analysis" subsection) the proposed project's contributions to localized cumulative impacts can be estimated. To represent *past* and, to an extent, *present projects* that contribute to ambient air quality conditions, the Energy Commission staff recommends the use of ambient air quality monitoring data (see the "Existing Ambient Air Quality" subsection), referred to as the *background*. The staff takes the following steps to estimate what are additional appropriate "present projects" that are not represented in the background and "reasonably foreseeable projects":

- First, the Energy Commission staff (or the applicant) works with the air district to identify all projects that have submitted, within the last year of monitoring data, new applications for an authority to construct (ATC) or permit to operate (PTO) and applications to modify an existing PTO within 6 miles of the project site. Based on staff's modeling experience, beyond 6 miles there is no statistically significant concentration overlap for non-reactive pollutant concentrations between two stationary emission sources.
- Second, the Energy Commission staff (or the applicant) works with the air district and local counties to identify any new area sources within 6 miles of the project site. As opposed to point sources, area sources include sources like agricultural fields, residential developments or other such sources that do not have a distinct point of emission. New area sources are typically identified through draft or final Environmental Impact Reports (EIRs) that are prepared for those sources. The initiation of the EIR process is a reasonable basis on which to determine what is "reasonably foreseeable" for new area sources.
- The data submitted, or generated from the applications with the air district for point sources or data from the EIR process for area sources, provides enough information to include these new emission sources in air dispersion modeling. Thus, the next step is to review the available EIR(s) and permit application(s), determine what sources must be modeled and how they must be modeled.
- Sources that are not new, but may not be represented in ambient air quality monitoring are also identified and included in the analysis. These sources include existing sources that are co-located with or adjacent to the proposed source (such as an existing power plant). In most cases, the ambient air quality measurements are not recorded close to the proposed project, thus a local major source might not be well represented by the background air monitoring data. When these sources are

included, it is typically a result of there being an existing source on the project site and the ambient air quality monitoring station being more than 2 miles away.

- The modeling results must be carefully interpreted so that they are not skewed towards a single source, in high impact areas near that source's fence line. It is not truly a cumulative impact of HECA if the high impact area is the result of high fence line concentrations from another stationary source and HECA is not providing a substantial contribution in the determined high impact area of the other source.

Once the modeling results are interpreted, they are added to the background ambient air quality monitoring data and thus the modeling portion of the cumulative assessment is complete. Due to the use of air dispersion modeling programs in staff's cumulative impacts analysis, the applicant must submit a modeling protocol, based on information requirements for an application, prior to beginning the investigation of the sources to be modeled in the cumulative analysis. The modeling protocol is typically reviewed, commented on, and eventually approved in the data adequacy phase of the Energy Commission licensing procedure. Staff typically assists the applicant in finding sources (as described above), characterizing those sources and interpreting the results of the modeling. However, the actual modeling runs are usually left to the applicant to complete. There are several reasons for this; modeling analyses take time to perform and require significant expertise, the applicant has already performed a modeling analysis of the proposed project alone (see the "Operation Modeling Analysis" subsection), and the applicant can act on its own to reduce stipulated emission rates and/or increase emission control requirements as the results warrant. Once the cumulative project emission impacts are determined, the necessity to mitigate the proposed project emissions can be evaluated, and the mitigation itself can be proposed by staff and/or the applicant (see the "Operation Mitigation" subsection).

The applicant requested a list of possible new stationary sources within six miles of the project site from the SJVAPCD in 2009 and again in 2011. The 2009 list included seven sources with minimal emissions potential (URS 2010). No significant stationary sources, with greater than 5 tons of permitted emissions of any pollutant, were identified within six miles of the project site. No additional possible new stationary sources were identified by the District in 2011 (HECA 2012e). Therefore, it has been determined that no stationary sources requiring a cumulative air dispersion modeling analysis exist within a 6-mile radius of the project site.

However, there is the potential for additional projects, such as renewable energy projects or oil and gas recovery projects, in the general area of the proposed project site. Additionally, there is the potential for significant additional development within the air basin. The corresponding potential for an increase in air basin emission sources is a major part of staff's rationale for recommending Conditions of Certification **AQ-SC6**, **AQ-SC7**, **AQ-SC9**, **AQ-SC10**, and **AQ-SC12** that are designed to mitigate the proposed project's cumulative impacts by substantially reducing mobile source and fugitive dust emissions during site operation. With these recommended mitigation measures, staff has concluded that the cumulative air quality impacts are less than significant.

While staff did not require a cumulative modeling analysis, the regional 1-hour NO_2 modeling analysis (**Air Quality Table 21**) that was completed to show compliance with the federal 1-hour NAAQS was a cumulative analysis that included a number of regional emissions sources as described by the applicant in the AFC Appendix E-7 (HECA 2012e), and the PDOC Appendix K (SJVAPCD 2013a).

Staff has considered the environmental justice population surrounding the site (see **Socioeconomics Figure 1**). Since the proposed project's cumulative air quality impacts have been mitigated to less than significant, there is no environmental justice issue for air quality cumulative impacts.

COMPLIANCE WITH LORS

The San Joaquin Valley Air Pollution Control District issued a Preliminary Determination of Compliance (PDOC) for the Hydrogen Energy California project on February 7, 2013 (SJVAPCD 2013a). The District will issue a Final Determination of Compliance (FDOC) after resolving any issues raised by the public or by agency comments. Compliance with all District rules and regulations was demonstrated to the District's satisfaction in the PDOC. The District's PDOC conditions are presented in the Conditions of Certification (**AQ-1** to **AQ-25**).

Staff submitted an official PDOC comment letter to SJVAPCD on March 28, 2013 and expects that the FDOC will contain revisions to conditions due to Energy Commission, applicant, or third party comments, and staff will provide revised FDOC findings and conditions of certification in the Final Staff Assessment (FSA).

FEDERAL

The District is responsible for issuing the federal New Source Review (NSR) permit and has delegated enforcement of the applicable New Source Performance Standards (NSPS, Subparts A, Db, GA, GG,Y, KKKK, and IIII). The U.S. Environmental Protection Agency's (EPA's) Prevention of Significant Deterioration (PSD) program has provisions for U.S. EPA to issue permits directly or to delegate administration to local agencies. Districts that are delegated and have adopted a SIP program approved by U.S. EPA are able to issue PSD permits that satisfy all of the federal Clean Air Act's PSD requirements. The SJVAPCD's PSD Rule 2410 was approved into the SIP on 6/1/2012, and U.S. EPA subsequently granted full PSD authority to the District; therefore the PSD permitting analysis has been completed by the District in the PDOC, and it will no longer be part of a separate federal action.

The PDOC issued by the SJVAPCD is undergoing a review process by the U.S. EPA concurrent with a public notice period. The U.S. EPA will provide any comments on the PDOC by the end of an extended comment period that concludes May 30, 2013. In addition the SJVAPCD held a public workshop to accept any verbal comments regarding the PDOC on April 2, 2012 and will hold a second public workshop on May 15, 2013. On March 28, 2013, staff provided the SJVAPCD a formal comment letter that identified concerns that staff has with the analysis and conditions contained in the PDOC, and expects to provide a second comment letter before the end of the comment period. Additionally, the District would have to review and address other agency and public comments, as appropriate.

Staff will evaluate any comments received from U.S. EPA on the PSA/DEIS and address them, if necessary, in the FSA.

General Conformity – DOE

Section 176(c)(1) of the Clean Air Act (CAA) requires that any entity of the federal government which engages in, supports, or in any way provides financial support for any activity demonstrate that the activity will conform to the applicable State Implementation Plans (SIPs) for achieving and maintaining National Ambient Air Quality Standards (NAAQS) for criteria pollutants before the federal entity proceeds with the activity. This requirement is referred to as the Clean Air Act's "General Conformity Rule" (GCR). As the HECA project will receive financial support from DOE, DOE must demonstrate that the project will conform to the applicable SIPs for all nonattainment and maintenance areas that would be affected by direct and indirect emissions from the project. DOE makes its conformity determination as part of their NEPA process.

A determination of conformity was performed for all the nonattainment and maintenance areas that would be affected by the HECA project – these areas are in the states of California, Arizona, and New Mexico. Emissions of criteria pollutants that would affect each of these areas from activities associated with construction and operation were estimated and compared to the *de minimis* thresholds established for the GCR to determine which emissions were subject to the rule.[16]

The estimates of emissions indicate that the total direct and indirect emissions of carbon monoxide (CO), particulate matter less than 10 microns in diameter (PM10), particulate matter less than 2.5 microns in diameter (PM2.5), and sulfur dioxide (SO_2) are below the GCR's thresholds for all years of construction and operation in all nonattainment and maintenance areas. Estimated construction and operational emissions of nitrogen oxides (NO_X) would exceed the GCR threshold during each year of construction and operation in the San Joaquin Valley Air Basin (SJVAB). Construction emissions of volatile organic compounds (VOCs) would exceed the threshold in 2014 and 2015 in the SJVAB. Accordingly, DOE must make a General Conformity Evaluation and Determination for NO_X in the SJVAB for the periods of construction and operation; and for VOC during construction. Appendix Air-1 contains the basis and supporting information used in this analysis.

The Applicant, HECA, has negotiated enforceable commitments with the San Joaquin Valley Air Pollution Control District (SJVAPCD) that call for HECA to provide funds to the District's Emission Reduction Incentive Program (ERIP), which the SJVAPCD would disburse as grants to emission reduction projects. The SJVAPCD would administer the projects and verify the emission reductions. The SJVAPCD would fund projects within the SJVAB that produce real, quantifiable, enforceable, emission reductions that would occur contemporaneously with the emissions from the project that are subject to the GCR. The District intends to fund enough projects to more than offset the HECA project's anticipated GCR emissions (that is, the SJVAPCD is requiring the applicant to provide funding for a surplus of emission reductions in the SJVAB). Through this

[16] Emissions of criteria pollutants that are regulated by a permit are exempt from the application of the GCR. Accordingly, most of the direct emissions from the operation of the HECA project are not subject to the conformity requirements.

mechanism, the District would ensure that construction and operational emissions of NO_X and VOCs from the project that exceed the GCR thresholds would be more than offset by the emission reductions achieved by the District's ERIP. On the basis of these agreements and the analysis in Appendix Air-1, DOE has determined that HECA would conform to the applicable SIPs and that its proposed financial assistance from the applicant complies with the requirements of the GCR.

General Conformity – Energy Commission Staff

The United States Department of Energy (DOE) is in the process of completing the project's General Conformity draft analysis. The draft analysis has been provided as Appendix Air-1 of this CEQA/NEPA document. Staff, along with U.S. EPA and other interested parties, will review and as necessary comment on the draft General Conformity analysis during its public review period, which will coincide with the PSA/DEIS public review period. The draft General Conformity analysis will be noticed in the Federal Register by DOE, and the final General Conformity determination will be completed by DOE separate from the Energy Commission's licensing decision.

The draft General Conformity analysis includes the determination of the annual construction period emissions and the applicable annual operating period emissions. These applicable operating period emissions include the project related traffic/rail and on-site mobile equipment emissions, but do not include the stationary source emissions that are permitted by and mitigated under the SJVAPCD rules and regulations. The analysis indicates that the project's construction emissions (NOx and VOC) and the project's operating emissions (NOx) exceed the general conformity annual thresholds for the San Joaquin Valley Air Basin. The analysis also indicates that the General Conformity thresholds for the other affected nonattainment area along the project's transportation routes are not exceeded.

HECA is not included as an emissions source within the SIP or within the growth forecasts in the SIP; therefore, the peak NOx and VOC emissions from the project will need to be mitigated. The peak annual NOx emissions are estimated to be 69.0 tons per year during the second year of construction and 43.6 tons per year during operation, and the peak VOC emissions are estimated to be 12.4 tons per year during the third year of construction. The applicant has agreed to fund the SJVAPCD's Emission Reduction Incentive Program (ERIP) to create the necessary emissions reductions to fully offset these emissions. The DOE was involved with the SJVAPCD and the applicant during the General Conformity emissions mitigation negotiations and agrees that funding the ERIP will produce real, quantifiable, enforceable and surplus emissions reductions in sufficient quantities to cover HECA's NOx and VOC General Conformity emissions obligations.

The emission reductions created through the projects funded by the ERIP could include the replacement of older equipment with newer lower emitting equipment or electrification of diesel engines, among other types of projects. Staff notes that one benefit of funding new emissions reductions in comparison with using existing ERCs is that other pollutant emissions, such as diesel particulate emissions, will also be reduced through the emissions reduction projects funded. The total funding is calculated based on the total construction period emissions (243.6 tons of NOx and 39.5 tons of VOC) and the first ten years of operations emissions (43.6 tons/year times 10 years). The mitigation fee is based on $9,350/ton with a 4 percent administration fee, so the total General Conformity based mitigation fee has been calculated to be approximately $7,000,000.

STATE

The applicant will demonstrate that the project will comply with Section 41700 of the California State Health and Safety Code, which restricts emissions that would cause nuisance or injury, through the issuance of the District's Preliminary Determination of Compliance and the Energy Commission's affirmative finding for the project.

The District's conditions and staff verifications will ensure compliance with the emission limit requirements of the ARB diesel engine air toxic control measures (ATCMs) and the applicant will also be required to comply with the idle restriction requirements of the ATCMs. District Policy APR 1905 – Risk Management Policy for Permitting New and Modified Sources, specifies that if there is an increase in emissions associated with a proposed new source, the District will perform an analysis to determine the possible impact to the nearest resident or worksite receptor. This analysis was included in the PDOC. The total facility prioritization score was greater than one. Therefore, a health risk assessment was required to determine the short-term acute and long-term chronic exposures from this project. Best available control technology for toxic emission control (T-BACT) was triggered for the CTG/HRSG, but all other facility sources were found to have prioritization scores below the trigger level for T-BACT. T-BACT for this unit would be satisfied with BACT for PM10 and VOC.

The applicant is exempt from the requirements of the Air Toxics "Hot Spots" risk assessment requirements (Section 44300 of the California Health and Safety Code) because the project will have had a risk assessment performed as part of its district permitting and the risk assessment, as provided in the District's PDOC, found that the project's emissions would result in less than significant health risks to the public.

LOCAL

As part of the Energy Commission's licensing process, in lieu of issuing a construction permit to the applicant for HECA, the District will prepare and present to the Energy Commission a DOC (both a PDOC, and after a public comment period, an FDOC). The PDOC was published on February 7, 2013 (SJVAPCD 2013a), and the FDOC will be published after the District has had time to respond to comments received on the PDOC, including comments from the applicant, the Energy Commission, and other interested parties such as U.S. EPA.

The District rules and regulations specify the emissions control and offset requirements for new sources such as HECA. Best Available Control Technology (BACT) will be implemented and emission reduction credits (ERCs) proposed by the Applicant and approved and certified by the District will fully mitigate project nonattainment pollutant emissions (including precursors) so that they would be consistent with the strategies and future emissions anticipated under the District's air quality attainment and maintenance plans. In addition, under a voluntary emissions reduction agreement with the SJVAPCD, the applicant will provide additional emissions mitigation through the funding of emission reduction projects.

The District's PDOC states that the proposed project is expected to comply with all applicable District rules and regulations. The DOC evaluates whether and under what conditions the proposed project will comply with the District's applicable rules and regulations, as described below.

Rule 1080 – Stack Monitoring

This rule grants the Air Pollution Control Officer (APCO) the authority to request the installation and use of continuous emissions monitors (CEMs), and specifies performance standards for the equipment and administrative requirements for record keeping, reporting, and notification. The facility will be equipped with CEMS for the following:

- CTG/HRSG: NOx, CO and O_2
- Nitric Acid Plant: NOx

The PDOC includes conditions to assure compliance with this rule.

Rule 1081 – Source Sampling

This rule requires adequate and safe facilities for use in sampling to determine compliance with emission limits, and specifies methods and procedures for source testing and sample collection. The PDOC includes periodic source testing requirements for the CTG, sulfur recovery unit/thermal oxidizer, CO_2 recovery and vent system, auxiliary boiler, ammonia startup heater, nitric acid unit, ammonium nitrate unit, and material handling units. Additionally, the PDOC includes fugitive emissions leak detection and repair program requirements identifying the sampling requirements for piping components and tanks in VOC or other criteria pollutant or hazardous air pollutant (HAP) service. The PDOC also includes total dissolved solids testing requirements for the cooling towers. Finally, there are other fuel and stream composition sampling requirements in the PDOC as necessary to determine composition necessary to calculate emissions or determine rule applicability and compliance. The PDOC includes conditions to assure compliance with this rule.

Rule 1100 – Equipment Breakdown

This rule defines a breakdown condition, the procedures to follow if one occurs, and the requirements for corrective action, issuance of an emergency variance, and reporting. This rule is applied to the owner of any source operation with air pollution control equipment, or related operating equipment that controls air emissions, or continuous monitoring equipment. Specific procedures for the CTG are included in the PDOC. The PDOC includes conditions to assure compliance with this rule.

Rule 2010 – Permits Required

This rule requires any person who is building, altering, replacing or operating any source that emits, may emit air contaminants, or may reduce emissions, to first obtain authorization from the District in the form of an Authority to Construct (ATC) or a Permit to Operate (PTO). For Energy Commission jurisdictional power plant projects, the District completes their analysis in the form of a DOC and the Authority to Construct and

Permit to Operate are granted by the District if they make a positive final DOC finding and the AFC is approved by the Energy Commission. The filing of the application with the District (HECA 2012e) and obtaining the ATC and PTO will fulfill the requirements of this rule.

Rule 2201 – New and Modified Stationary Source Review Rule

The main function of the District's New Source Review Rule is to allow for the issuance of Authorities to Construct, Permits to Operate, the application of Best Available Control Technology (BACT) to new or modified permit source and to require the new permit source to secure emission offsets. In addition, see Rule 2010, above.

Section 3.16 – Daily Emissions Limitation (DEL)

This requires daily emission limitations (DELs) restricting a unit's maximum daily emissions to a level at or below the emissions associated with the maximum design capacity. DELs must be contained in the applicable permits and enforceable on a daily basis. The PDOC includes conditions to assure compliance with the DELs.

Section 4.1 – Best Available Control Technology

Best Available Control Technology (BACT) is defined as the most stringent emission limitation or control technique of the following: a) achieved in practice for a category and class of source; b) contained in any State Implementation Plan and approved by the U.S. EPA for a category and class of source; c) contained in an applicable federal New Source Performance Standard; or d) any other emission limitation or control technique that the District's Air Pollution Control Officer (APCO) finds is technologically feasible and cost effective. BACT is required for any new or modified emission unit that results in an emissions increase of at least 2.0 lb/day. However, Section 4.2.1 states that BACT is not required for CO emissions from any new or modified emissions unit if those sources emit less than 200,000 lb/year of CO. In the case of HECA, BACT applies for the following equipment and pollutants:

- Gas Turbine/HRSG – NOx, CO, VOC, SOx, PM10, CO_2
- Railcar/Truck Unloading and Transfer Systems – PM10
- Feedstock Storage, Blending and Reclaim System – PM10
- Feedstock Grinding/Crushing and Drying System – PM10
- Gasification System – CO, VOC, CO_2
- Gasification Solids Handling System – PM10
- Sulfur Recovery System – SOx
- CO_2 Recovery and Vent System – VOC, CO, CO_2
- Auxiliary Boiler – NOx, CO, VOC, SOx, PM10
- Three Cooling Towers – PM10
- Gasification Flare – NOx, CO, VOC, SOx, PM10
- Sulfur Recovery Unit Flare – NOx, CO, SOx, PM10

- Rectisol® Flare – NOx, CO, VOC, SOx, PM10
- Ammonia Startup Heater – NOx, CO, VOC, SOx, PM10
- Urea Absorber and Urea Pastillation Unit – PM10
- Nitric Acid Unit – NOx
- Ammonium Nitrate Unit – PM10
- Urea Storage and Handling Operation – PM10
- Emergency Generator Engines and Firewater Pump – NOx, CO, VOC, PM10

The District has determined that the control equipment or basic equipment proposed for HECA currently meets the requirements of BACT.

The PDOC includes conditions to assure compliance with the BACT determinations, including the gas turbine/HRSG BACT demonstration requirements.

Section 4.5 through 4.13 – Emission Offset Requirements

Section 4.5 specifies that emissions offsets for new or modified sources are required when their emissions are equal to or exceed the following levels:

- Oxides of Nitrogen, NOx – 20,000 lbs/year;
- Volatile Organic Compounds, VOC – 20,000 lbs/year;
- Carbon Monoxide, CO – 200,000 lbs/year;
- PM10 – 29,200 lbs/year;
- Sulfur Oxides, SOx – 54,750 lbs/year.

If constructed, HECA would exceed the above emission levels for NOx, VOC, CO, PM10 and SOx based on the permitted equipment emission limits and the applicant's requested facility operation.

Section 4.6 specifies that emissions offsets are not required for increases of CO in attainment areas (such as in the vicinity of the proposed HECA project), if the applicant demonstrates that the emissions increase will not cause or contribute to a violation of the ambient air quality standards, and that those emissions are consistent with Reasonable Further Progress. The District completed a modeling analysis for the project's CO emissions using AERMOD. Worst case 1-hour and 8-hour CO impacts were added to the worst case ambient background concentrations and compared to the AAQS. The modeling results shown below demonstrate that the proposed increases in CO emissions will not cause a violation of the CO AAQS and therefore offsets will not be required:

	1 hr std μg/m^3	**8 hr std μg/m^3**
Worst Case Background	4,581	2,485
Facility Increment	7,244	2,856
Total	11,825	5,341
AAQS	23,000	10,000

Section 4.6 also specifies that emergency equipment used exclusively as emergency standby equipment for electrical power generation is exempt from emission offset requirements.

Section 4.8 specifies that the required emission offsets shall be adjusted according to the distance of the offset from the proposed project's site. The ratios are:

- NOx and VOC major sources - 1.5:1, regardless of distance
- PM2.5 - 1:1, regardless of distance
- Other Pollutant Distance Ratios
  - Internal or on-site source – 1 to 1;
  - Within 15 miles of the source – 1.2 to 1 (non-major source), 1.3 to 1 (major source); and
  - 15 miles or more from the source – 1.5 to 1.

Section 4.13.1 specifies that major sources (defined as those sources that emit greater than 25 tons of NOx and VOC, 100 tons CO, or 70 tons of PM10 and SOx) that are shut down and thus generate an ERC may not be used as an offset for a new major source (like HECA) unless those ERCs are included in an U.S. EPA-approved attainment plan.

Section 4.13.3 allows for the use of interpollutant offsets (including PM10 precursors for PM10) on a case-by-case basis, provided that the applicant demonstrates that the emissions increase will not cause a violation of any ambient air quality standard. The ratio for interpollutant trading shall be based on an air quality analysis and shall be equal to or greater than the minimum offsetting requirement (the distance ratios) of Section 4.8.

Section 4.13.3.2 allows for the use of interpollutant offsets between PM2.5 and PM2.5 precursors at specific ratios as established by the U.S. EPA, or as approved into the SIP by the U.S. EPA. The District has determined this restriction on the use of interpollutant offsets according to these ratios is only applicable to new major sources and major modifications of PM2.5. This requirement would not be applicable since the proposed facility's emissions of PM2.5 are low enough that it is not a new major source of PM2.5.

Section 4.13.4 requires Actual Emissions Reductions (AER) used as offsets to have occurred during the same calendar quarter as the emissions increases being offset. Exceptions to this rule (4.13.7 through 4.13.9) allow PM emission reductions that occurred from October through March to offset PM emissions occurring anytime during the year, for NOx and VOC emission reductions that occurred from April through November to offset NOx and VOC emissions occurring anytime during the year.

The District has evaluated the offset need and offsets proposed by the applicant, including evaluating the proposed interpollutant offsets. The District has found that the applicant's offset proposal will comply with these regulations (SJVAPCD 2013a).

Section 4.14 – Ambient Air Quality Standards

Section 4.14.1 requires that emissions from new stationary sources subject to public noticing requirements be modeled to determine if the emissions cause or worsen a violation of an AAQS. This District can consider mitigation of emissions through offsets in this determination. The District's modeling analysis provided in Appendix K of the PDOC determined that all pollutants would either remain below the AAQS or below relevant Significant Impact Levels (SILs) with the exception of the 24-hour and annual PM2.5 SILs. Therefore, to ensure that the project's PM2.5 emissions do not create adverse impacts, the District is requiring offsets to fully mitigate the total PM2.5 emissions from the project. Taking this mitigation into consideration, the District has determined that the project will not cause or make worse a violation of the PM2.5 AAQS. This project is not a major source of PM2.5 emissions and otherwise would not require PM2.5 emissions offsets. Compliance with this rule is expected.

Section 4.15 – Additional Requirements for new Major Sources and Federal Major Modifications

Section 4.15.2 requires that the owner of a proposed new major source or federal major modification demonstrate to the satisfaction of the District that all major stationary sources subject to emission limitations that are owned or operated by the applicant or any entity controlling or under common control with the applicant in California, are in compliance or on a schedule for compliance with all applicable emission limitations and standards. The applicant has indicated that they will provide a certification in compliance with this regulation prior to issuance of the FDOC. Compliance with this rule is expected.

Rule 2410 – Prevention of Significant Deterioration

Rule 2410 incorporates federal PSD rule requirements into the District's rules and regulations, and became effective as of June 1, 2012. PSD applies to major sources designated in attainment with NAAQS. Rule 2410 requires an air analysis demonstrating compliance with NAAQS for applicable pollutants. Therefore modeling was performed to demonstrate that regulated air pollutants would not cause or contribute to a violation of applicable NAAQS, PSD increments, Air Quality Related Values (AQRV), or result in impacts to visibility and soil and vegetation. The project is designated a PSD source for CO, NOx and PM10. The District's modeling analysis shown in Appendix K of the PDOC indicated that project specific impacts would exceed the Class II SILs for 1-hour CO and 1-hour NO_2. An additional refined cumulative screening analysis for CO determined that the cumulative CO impacts would be well below the NAAQS, so no significant CO impacts would occur. Additional cumulative impact modeling and PSD increment analysis was completed for NO_2. This refined modeling determined that the project would not cause new exceedances of the 1-hour NO_2 NAAQS. In summary, SJVAPCD determined the proposed project would not cause, or significantly contribute to, a violation of the NAAQS and demonstrated compliance with other modeling requirements of this rule. Compliance with this rule is expected.

Rule 2520 – Federally Mandated Operating Permits

Rule 2520 requires that a project owner file a Title V Operating Permit from the U.S. EPA with the District within 12 months of commencing operation. A project is subject to this requirement if any of the following apply: the project is a major stationary source (under PSD definitions), it has the potential to emit greater than 100 tons per year of a criteria pollutant, any equipment permitted is subject to New Source Performance Standards, the project is subject to Title IV Acid Rain program, or the owner is required to obtain a PSD Permit. The Title V Permit application requires that the owner submit information on the operation of the air polluting equipment, the emission controls, the quantities of emissions, the monitoring of the equipment as well as other information requirements. Title V requirements apply to HECA and the PDOC includes conditions to assure compliance with this rule.

Rule 2540 – Acid Rain Program

A project greater than 25 megawatts (MW) and installed after November 15, 1990, must submit an acid rain program permit application to the District. The acid rain requirements will become part of the Title V Operating Permit (Rule 2520). Monitoring of the NOx and SOx emissions and a relatively small quantity of SOx allowances (from a national SOx allowance bank) will be required as well as the use of a NOx CEM. An acid rain application will need to be submitted to EPA at least 24 months before the date the unit expects to generate electricity. The PDOC includes conditions to assure compliance with this rule.

Rule 2550 – Federally Mandated Preconstruction Review for Major Sources of Air Toxics

Rule 2550 applies to new facilities classified as a major toxics source. The project as proposed is not a major air toxics source because individual HAP emissions are below ten tons per year and total stationary HAP emissions are below twenty five tons per year. The PDOC includes conditions to assure the project would remain below the major air toxics source thresholds. Initial testing will be required for the CO_2 recovery and vent system and CTG. The PDOC includes conditions to assure compliance with this rule.

Rule 4001 – New Source Performance Standards

Rule 4001 specifies that a project must meet the requirements of the Federal New Source Performance Standards (NSPS), according to Title 40, Code of Federal Regulations, Part 60, Chapter 1. The specific subparts that are applicable to HECA include:

- Subpart A - General Provisions. Section 60.18 – General Control Device and Work Practice Requirements.
- Subpart Db - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
- Subpart Ga – Standards of Performance for Nitric Acid Plants for Which Construction, Reconstuction, or Modification Commences After October 14, 2011
- Subpart Y - Standards of Performance for Coal Preparation and Processing Plants
- Subpart GG – Standards of Performance for Stationary Gas Turbines
- Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

- Subpart KKKK - Standards of Performance for Stationary Combustion Turbines

Subpart A provides general requirements that apply to control devices. For this project this subpart applies to the sulfur recovery unit (SRU) and Rectisol® flares. The specific requirements of this rule relate to visible emissions limitations and monitoring, a requirement to maintain a flame at all times (i.e. pilot flame), and compliance recordkeeping requirements. The PDOC includes conditions to assure compliance with this rule.

Subpart Db is applicable to steam generating units with a heat input capacity of greater than 100 MMBtu/hr. The proposed auxiliary boiler is applicable to this Subpart. Applicable requirements include NOx standards and testing, exhaust monitoring and recordkeeping requirements. Facilities can demonstrate compliance through the monitoring of steam generating unit operating conditions if a plan is approved by the EPA Administrator. Therefore the facility will be required to submit a plan to EPA for approval within 360 days of initial startup. The PDOC includes conditions to assure compliance with this rule.

Subpart G is applicable to each nitric acid production unit commencing construction after August 17, 1971 and on or before October 14, 2011. Any facility commencing construction after October 14, 2011 is subject to Subpart Ga.

Subpart Ga is applicable to the proposed nitric acid unit. Subpart Ga establishes performance standard of 0.20 lb-NOx per ton of nitric acid produced (expressed as 100 percent nitric acid), averaged over a 24-hour rolling hour period. The PDOC includes conditions to assure compliance with this rule. Subpart Ga also requires a CEMS for measuring NOx. In addition the subpart outlines monitoring, testing, operational specifications, recordkeeping and reporting requirements for the CEMS.

Subpart Y is applicable to coal preparation and processing plants processing more than 181 megagrams (200 tons) of coal per day. The following processes are subject to this Subpart:

- Railcar Unloading and Transfer System
- Truck Unloading and Transfer System
- Feedstock Storage, Blending, and Reclaim System
- Feedstock Grinding/Crushing and Drying System

Subpart Y exempts thermal dryers receiving all of their thermal input covered under another subpart from the requirements in Subpart Y. The proposed dryer receives all of its thermal input from the treated exhaust of the CTG/HRSG subject to Subpart KKKK. Subpart KKKK requirements (described below) include emission control performance standards such as visible emission limitations, performance testing, monitoring, and recordkeeping requirements. The PDOC includes conditions to assure compliance with this rule.

Subpart GG is applicable to all stationary gas turbines with a heat input greater than 10.7 gigajoules per hour (10.2 MMBtu/hr) commencing construction after October 3, 1977. The proposed CTG is subject to this subpart. However, it is also subject to Subpart KKKK which has provisions exempting CTGs regulated by Subpart KKKK from Subpart GG requirements.

Subpart IIII is applicable to the emergency engines and emergency fire pump. This subpart establishes emission standards, fuel requirements, hour meter requirements, limits maintenance and testing and requires proper maintenance for the engines and control devices. The facility will comply with the use of the latest EPA Tier Certification level for the applicable horsepower range, ARB-certified fuel, installation of non-resettable hour meter, maintenance and testing limitations, and proper maintenance. The PDOC includes conditions to assure compliance with this rule.

Subpart KKKK is applicable to all stationary gas turbines with a heat input greater than 10.7 gigajoules per hour (10.2 MMBtu/hr) commencing construction after February 18, 2005. Subpart KKKK requires that a project meets specific NOx and SO_2 standards, meets continuous emission monitoring system requirements, meets various emission and fuel reporting requirements, and meets specified NOx and SOx performance testing requirements. The PDOC includes conditions to assure compliance with this rule.

Rule 4002 – National Emission Standards for Hazardous Air Pollutants

Rule 4002 incorporates the National Emission Standards for Hazardous Air Pollutants (NESHAPs) from Part 61 and Part 63, Chapter I, Subchapter C, Title 40 CFR and applies to major sources of Hazardous Air Pollutants (HAPs). HECA will conduct an initial speciated HAPS compliance source test to demonstrate it is not a major source of HAPS. The PDOC includes conditions to assure compliance with this rule.

Emergency engines are subject to the following NESHAP rule if they are operated at a major or area source of HAPS.

- Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Emissions (RICE)

Subpart ZZZZ requires the engines to comply with CFR 60 Subpart IIII. Additional notification is required for engines with an initial performance test. Testing is not required for emergency engines. Therefore, the notification requirement is not applicable. The PDOC includes conditions to assure compliance with CFR 60 Subpart IIII and therefore compliance with this rule.

The IGCC complex, specifically the gasification unit, CTG/HRSG, and Coal Dryer are subject to the following NESHAP rule:

- Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

This rule contains various emissions limits for coal and oil fired power plants by fuel and type of plant. The project's IGCC emissions are regulated with the emissions limits presented in Table 1 of this rule. The IGCC emissions limits are as follows:

- Filterable particulate matter[17] - $7.0E^{-2}$ lbs/MWh (megawatt-hour)
- Hydrogen chloride[18] (HCl) – $2.0E^{-3}$ lbs/MWh
- Mercury (Hg) – $3.0E^{-3}$ lbs/GWh (gigawatt-hour)

Staff's review of the emissions estimates provided by the applicant indicated that they will comply with these emissions limits. The applicant is proposing mercury control systems to remove mercury evolved in the gasification system to remove it from the syngas prior to its combustion and from the coal dryer exhaust to collect any mercury volatilized from the coal in the coal dryer. However, the PDOC does not contain any conditions specific to ensure compliance with this rule. Therefore, staff has included Condition of Certification **AQ-SC13** to address compliance with this rule. Staff anticipates that based on our comments on the PDOC conditions, the District will add conditions to the FDOC to adequately address compliance with this NESHAPS regulation, and if so staff will remove condition **AQ-SC13**.

Rule 4101 – Visible Emissions

This rule prohibits visible air emissions, other than water vapor, of more than No. 1 on the Ringelmann chart (20 percent opacity) for more than three minutes in any one-hour. Considering the control equipment (SCR/CO catalyst) on the gas turbine and other stationary sources, no visible emissions greater than 20 percent opacity are expected during normal operation of the facility. The PDOC includes conditions to assure compliance with this rule.

Rule 4102 – Nuisance

This rule prohibits any emissions "which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public or which endanger the comfort, repose, health or safety of any such person or public or which cause or have a natural tendency to cause injury or damage to business or property." The types of emission sources at the facility, when operating normally (see Rule 1100 above for equipment breakdown requirements), are not expected to cause the potential for nuisance. The PDOC includes a condition to assure compliance with this rule.

Rule 4201 – Particulate Matter Concentration

Rule 4201 limits particulates emissions from any source that emits or may emit dust, fumes, or total suspended particulate matter to less than 0.1 grain per dry standard cubic foot (gr/dscf) of gas calculated to 12 percent of carbon dioxide. The particulate matter grain loadings expected for the proposed facility equipment are less than this standard. The PDOC includes a condition to assure compliance with this rule.

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[17] This standard is either a filterable particulate matter emissions limit or speciated non-Hg metals emissions limits. In this case the applicant will be complying using the filterable particulate matter emissions limit.

[18] This standard is either based on hydrogen chloride or sulfur dioxide, where the sulfur dioxide emissions standard must be monitored for compliance using a continuous emissions monitoring system (CEMS). The applicant is not proposing a sulfur dioxide CEMS, and so is proposing to comply with the hydrogen chloride emissions standard.

Rule 4202 – Particulate Matter Emission Rate

This rule limits particulate matter emissions for any source operation, which emits or may emit particulate matter emissions, by establishing allowable emission rates. Calculation methods for determining the emission rate based on process weight are specified. Gaseous and liquid fuels are exempt, so the turbines and the engines are exempt from this rule.

The project's proposed cooling towers and fuel feedstock handling equipment are subject to this rule and the emissions from the cooling towers were found to comply in the PDOC's engineering analysis and the PDOC includes conditions to assure compliance with this rule.

Rule 4301 – Fuel Burning Equipment

Rule 4301 provides limits on the concentration of combustion contaminants and specifies maximum emission rates for NOx, SO_2, and combustion contaminant emissions (particulates) for any fuel burning equipment, except for air pollution control equipment which is exempt. The specified limits are 140 lbs/hour of NOx, calculated as NO_2, 200 lbs/hour of SO_2, 0.1 gr/dscf of combustion contaminants in exhaust flue gas calculated to 12 percent of carbon dioxide, and 10 lbs/hour of combustion contaminants. The combustion turbine generator and emergency engines do not meet the definition of fuel burning equipment as stated in this rule and are therefore exempt. However, the auxiliary boiler is subject to this rule, and the District has found that the maximum hourly emissions from the auxiliary boiler would be less than the emission limits set by this rule. Therefore, compliance with this rule is expected.

Rule 4304 – Equipment Tuning Procedure for Boilers, Steam Generators and Process Heaters

Rule 4304 provides equipment tuning procedures and frequencies for boilers, steam generators, and process heaters. This rule applies to the auxiliary boilers and the PDOC has a condition requiring compliance with this condition; therefore, compliance with this rule is expected.

Rule 4311 – Flares

This rule limits emissions of VOC, NOx, and SOx from the operation of flares. All three flares (gasification flare, SRU flare, and Rectisol® flare) are subject to this rule. The PDOC includes conditions to assure compliance with this rule.

Rule 4320 – Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heater Greater Than 5.0 MMBtu/hr

This rule limits emissions of NOx, CO, SO_2, and PM10 emissions from permit units burning greater than 5 MMBtu/hr of fuel. The auxiliary boiler and the ammonia synthesis unit startup heater are subject to this rule, and the PDOC includes conditions to assure compliance with this rule. Additionally, the other rules apply to these two sources:

- Rule 4305 Boilers, Steam Generators and Process Heaters – Phase 2
- Rule 4306 Boilers, Steam Generators and Process Heaters – Phase 3

However, Rule 4320 has more stringent requirements than these two rules and compliance with Rule 4320 will ensure compliance with all three of these rules.

Rule 4702 – Internal Combustion Engines – Phase 2

This rule limits emissions of NOx, CO, and VOC from internal combustion engines with a rated brake horsepower greater than 50 hp. Pursuant to Section 4.3.1.2 of this rule, the proposed emergency engines are exempted, and only need to meet the following recording requirements of Section 6.2.3 of this rule:

- 6.2.3.1 Total hours of operation,
- 6.2.3.2 The type of fuel used,
- 6.2.3.3 The purpose for operating the engine,
- 6.2.3.4 For emergency standby engines, all hours of non-emergency and emergency operation shall be reported, and
- 6.2.3.5 Other support documentation necessary to demonstrate claim to the exemption.

The PDOC includes conditions to assure compliance with this rule.

Rule 4703 – Stationary Gas Turbines

Rule 4703 limits NOx and CO emissions from stationary gas turbines. The rule establishes requirements for testing, monitoring, and record keeping for NOx and CO emissions from new or modified stationary gas turbines with a designed power of 0.3 MW or higher and/or a maximum heat input rating of more than 3,000,000 Btu per hour. Hydrogen-rich fuel does not meet the definition of gas fuel as stated in this rule. Therefore, this rule would not apply when the CTG is fired on hydrogen-rich fuel. However, the CTG is subject to this rule when fired on natural gas or co-fired with a blend of natural gas and hydrogen. The PDOC includes conditions to assure compliance with this rule.

Rule 4801 – Sulfur Compounds

Rule 4801 limits the emissions of sulfur compounds to no greater than 0.2 percent by volume calculated as SO_2 on a dry basis averaged over 15 consecutive minutes. The use of PUC-regulated natural gas and ARB-certified diesel fuel, and the District conditions providing fuel sulfur limits on the hydrogen-rich fuel will assure compliance with this rule.

Rule 7012 – Hexavalent Chromium – Cooling Towers

This rule limits emissions of hexavalent chromium from circulating water in cooling towers. Section 5.2.1 of this rule requires no hexavalent chromium containing compounds can be added to cooling tower circulating water. The PDOC includes conditions to assure compliance with this rule.

REGULATION VIII - FUGITIVE PM10 PROHIBITIONS

The District has included several conditions in the PDOC that relate mitigation and compliance requirements of these rules (**AQ-1-10** through **-19**) that would apply during project construction and operation. Staff's construction fugitive dust mitigation condition (**AQ-SC3**) generally includes the same requirements as these District rules but has been revised to note that any District rule requirement that is more stringent than those required in the staff condition shall apply. The PDOC includes conditions to assure compliance with all Regulation VIII rules, including:

Rule 8011 – General Requirements

Rule 8011 specifies the types of chemical stabilizing agents and dust suppressant materials that can (and cannot) be used to minimize fugitive dust emissions from anthropogenic (man-made) sources. The rule also specifies test methods for determining compliance with visible dust emission (VDE) standards and for stabilized surface conditions, soil moisture content, silt content for bulk materials, silt content for unpaved roads and unpaved vehicle/equipment traffic areas, and threshold friction velocity (TFV). The facility owner/operator would be required to retain records only for those days that a control measure was implemented, and the facility owner/operator must keep the records for one year following project completion to demonstrate compliance. An owner subject to Rule 2520 (Federally Mandated Operating Permits) shall keep such records for five years. A fugitive dust management plan for unpaved roads and unpaved vehicle/ equipment traffic areas is discussed as an alternative for Rule 8061 and Rule 8071 (see below). The PDOC includes conditions to assure compliance with Regulation VIII rules.

Rule 8021 – Construction, Demolition, Excavation, Extraction and Other Earthmoving Activities

Rule 8021 requires fugitive dust emissions throughout construction activities (from pre-activity to active operations and during periods of inactivity) to comply with the conditions of a stabilized surface area and to not exceed an opacity limit of 20 percent. This can be accomplished by means of water application, chemical dust suppressants, or constructing and maintaining wind barriers. A Dust Control Plan is also required and shall be submitted to the APCO prior to the start of any construction activities on any site that will include 10 acres or more of disturbed surface area for residential developments, 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. HECA exceeds these limits and therefore must develop a dust control plan, but compliance with the requirements of this rule is expected.

Rule 8031 – Bulk Materials

Rule 8031 limits the fugitive dust emissions from the outdoor handling, storage and transport of bulk materials. This rule requires fugitive dust emissions to comply with the conditions of a stabilized unpaved road surface and to not exceed an opacity limit of 20 percent. It specifies that bulk materials be transported using wetting agents, allow appropriate freeboard space in the vehicles, or be covered. It also requires that stored materials be covered or stabilized. Compliance is expected.

Rule 8041 – Carryout and Trackout

Rule 8041 limits carryout and trackout during construction, demolition, excavation, extraction, and other earthmoving activities (Rule 8021, above), from bulk materials handling (Rule 8031, above), from paved and unpaved roads (Rule 8061, below), and from unpaved vehicle and equipment traffic areas (Rule 8071, below) where carryout has occurred or may occur. Carryout and trackout for this project is only related to the construction period and staff's construction fugitive dust mitigation condition **AQ-SC3** includes requirements to assure compliance with Regulation VIII rules. Compliance is expected.

Rule 8051 – Open Areas

Rule 8051 requires any open area of 0.5 acres or more within urban areas, or three acres or more within rural areas, and contains at least 1,000 square feet of disturbed surface area to comply with the conditions of a stabilized unpaved road surface and to not exceed an opacity limit of 20 percent, by means of water application, chemical dust suppressants, paving, applying and maintaining gravel, or planting vegetation. HECA exceeds these rule trigger limits, but compliance with this rule is expected.

Rule 8061 – Paved and Unpaved Roads

Rule 8061 specifies the width of paved shoulders on paved roads and guidelines for medians. It requires gravel, roadmix, paving, landscaping, watering, and/or the use of chemical dust suppressants on unpaved roadways to prevent exceeding an opacity limit of 20 percent. Exemptions to this rule include "any unpaved road segment with less than 26 annual average daily vehicle trips (AADT)." Compliance is expected.

Rule 8071 – Unpaved Vehicle/Equipment Traffic Areas

This rule limits fugitive dust from any unpaved vehicle and equipment traffic area by using gravel, roadmix, paving, landscaping, watering, and/or the use of chemical dust suppressants to prevent exceeding an opacity limit of 20 percent. Exemptions to this rule include "unpaved vehicle and equipment traffic areas with less than 50 Average Annual Daily Trips (AADT)." Compliance is expected.

DIRECT AND INDIRECT IMPACTS OF THE NO-ACTION ALTERNATIVE

Under the No-Action Alternative, DOE would not provide financial assistance to the applicant for the HECA Project. The applicant could still elect to construct and operate its project in the absence of financial assistance from DOE, but DOE believes this is unlikely. For the purposes of analysis in the PSA/DEIS, DOE assumes the project would not be constructed under the No-Action Alternative. Accordingly, the No-Action Alternative would have no impacts associated with this resource area.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

The table below contains staff's responses to comments received pertinent to the criteria air pollutant topics addressed in this section that were submitted by government agencies, intervenors, and the public. Please note some of the comments received refer to multiple environmental assessment resource topics such as public health, greenhouse gases and carbon sequestration, water resources, etc. The responses provided in the table below reference only the comments or portions of the comments related to criteria pollutant air quality issues. Please see the other environmental assessment resource topic sections for responses to comments or portions of comments regarding those issue areas. This comment response includes responses to comments provided to the Energy Commission and to the DOE.

Submitted by	COMMENT and RESPONSE
AGENCY: Parks and Rec.	
Agency – Parks and Rec (TN-58852) 10/21/2010	Comment: (summarized) The Tule Elk Reserve is located less than one mile from the integrated gasification combined cycle (IGCC) main complex. The Reserve is considered a sensitive land use receptor area per the San Joaquin Valley Air Pollution Control District. According to the air quality analysis, even after very aggressive mitigation measures the construction-related pollutants of PM10 impacts are predicted to be potentially significant beyond the fence line and if constructed the proposed project would exceed air quality standards levels for NOx, VOC, CO, and SOx. As a sensitive land use receptor area and an adjacent property owner we believe that these potential offensive air pollutants could significantly impact the park visitor's experience. In addition, this project could create a potential health risk for individuals and groups that regularly visit the Reserve, including the elderly, school groups and families with young children. We are concerned that the proposed mitigation measures will not sufficiently reduce and/or eliminate these emissions of odorous substances within the Reserve. Response: The project would create a new emissions source that would likely incrementally increase existing concentrations of all criteria pollutants surrounding the site. Staff and the SJVAPCD have found that these incremental increases in non-attainment pollutant impacts (that is, for pollutants that currently exceed air quality standards) would not be substantial and that the project would not create any new exceedances of ambient air quality standards for attainment pollutants (that do meet these standards). Staff has also determined that offensive odors would not occur past the fence line under normal operating conditions. Additionally, the project would be required to provide emissions mitigation as follows: 1) BACT emissions controls and emissions offsets as required by District regulations; 2) emissions controls as recommended by staff conditions of certification to reduce emissions from the onsite and offsite emissions sources that would not be regulated by the District rules; and 3) through the completion of two emissions reduction funding agreements with the District that would fund additional

	emissions reductions in the San Joaquin Valley as necessary to fulfill General Conformity offset requirements, other District determined CEQA mitigation needs, and a voluntary agreement to address NOx emissions efficiency issues. These mitigation measures would reduce incremental impacts sufficiently such that they would not be significant.
Agency – Parks and Rec (TN-58852) 10/21/2010	<u>Comment</u>: (summarized) The proposed project will exceed the Prevention of Significant Deterioration (PSD) emission thresholds for NO_2 and CO as it pertains to the Air Quality Related Values (AQRVs). We are concerned that the proposed project will degrade and reduce the visibility within the Reserve. Public Resource Code Section 5019.65 identifies State Natural Reserves as, "... areas embracing outstanding natural or scenic characteristics or areas containing outstanding cultural resources of statewide [sic] significance.” The purpose of a State Reserve is to preserve its native ecological associations, unique faunal or floral characteristics, geologic features, and scenic qualities in a condition of undisturbed integrity. Resource manipulation shall be restricted to the minimum required to negate the deleterious influence of man. Currently, State Parks has classified only 17 State Natural Reserve units out of 279 units. As an adjacent property owner, we are concerned that these airborne pollutants will diminish the clarity and color of what the park visitors see, negatively impacting the park visitor's experience. We request that a visibility analysis be completed including photo enhancements of the project's impacts to the visibility within the Reserve. Appropriate mitigations measures should be implemented to reduce and/or eliminate these manmade effects on the visibility within the Reserve. <u>Response</u>: The project would be a new air pollutant emissions source and so would to some small degree impact visibility near the project site, either due to the effects of criteria pollutants or due to water vapor plumes from the cooling tower or other exhausts. This section includes a discussion of the required AQRV modeling analysis that is part of the PSD process. U.S. EPA requires the project to perform a significant impact level analysis for Class 1 areas (national parks, wilderness areas and national monuments). SJVAPCD performed this modeling analysis using AERMOD. Although the closest Class 1 Area is 60 km southwest, AERMOD evaluated impacts out to 50 kilometers. Results indicated maximum impacts would fall within 2-3 kilometers from the facility boundary. Predicted concentrations are below the Class I significant impact level (SIL) at 20-30 kilometers from the facility boundary. Visibility impairment associated with HECA was analyzed using procedures from EPA’s Workbook for Plume Visual Impact Screening and Analysis. A screening analysis conducted per Federal Land

	Manager's (FLM) guidance indicated that the project's emissions were below FLM screening criteria for the nearest Class I and Class II Areas, so no further visibility modeling was required. Visibility modeling addresses long range visibility impacts and does not address short-range visibility impacts, partly because the impacts of a single air pollutant emissions source, even one as large as HECA, isn't a visibility concern over a short distance. The potential for visual resource impacts, including short range impacts of the water vapor plumes from the project are discussed in the Visual Resources section of this document.
AGENCY: U.S. Environmental Protection Agency (U.S. EPA)	
Agency – U.S. EPA (TN-66381) 7/26/2012	Comment: (summarized and paraphrased) Ambient Conditions The DEIS should include a detailed discussion of ambient air conditions including the area's attainment or nonattainment status for all NAAQS. The project area is designated as nonattainment for the annual 24-hour PM2.5 standard and extreme nonattainment for the 8-hour ozone standard. Response: The PSA/DEIS includes a detailed discussion of ambient air conditions including the attainment and non-attainment status for all NAAQS and CAAQS. The attainment status information is presented in **Air Quality Table 4** and the local air quality background values for the past several years are presented in **Air Quality Table 5**.
Agency – U.S. EPA (TN-66381) 7/26/2012	Comment: (summarized) General Conformity The DEIS should address the applicability of Clean Air Act (CAA) Section 176 and EPA's general conformity regulations at 40 CFR Part 51 and 93 for those pollutants that do not exceed the NAAQS. The General Conformity rule does not require linking the conformity determination and the NEPA process, it is recommended the processes are linked for convenience and efficiency. Response: The draft General Conformity analysis is provided as Appendix Air-1 and is being linked with the NEPA process.
Agency – U.S. EPA (TN-66381) 7/26/2012	Comment: (summarized) Permitting for Attainment and Nonattainment Pollutants The DEIS should summarize all existing air quality regulation, the required demonstration and the respective air permitting agencies for federal attainment, federal non-attainment and hazardous air pollutant emission. The project will require a Significant Deterioration (PSD) permit per section 165 of the Clean Air Act for attainment pollutants. The project will require a Nonattainment New Source Review (NNSR) permit for nonattainment pollutants (40 CFR 51.160-51.165).

	For a major new source subject to PSD, the emissions must be quantified to demonstrate which attainment pollutants trigger the PSD significant emission rate thresholds; Best Available Control Technology (BACT) must be applied to those pollutants; air quality modeling analyses must be conducted for the applicable pollutants; and additional impacts analyses must be addressed. For a major new source subject to NNSR, at a minimum, emissions must be quantified to demonstrate which nonattainment pollutants trigger the New Source Review requirements, Lowest Achievable Emission Rate (LAER) must be applied to those pollutants, and emission credits must be obtained for the applicable pollutants. The following requirements should be addressed in the DEIS: BACT, LAER and air quality modeling considerations. It is important to ensure that there is not a violation of the NAAQS or applicable PSD increments, identify nearby areas designates as Class I and Class II areas, and confirm whether there are potential impacts on impairment to visibility, deposition or other air quality-related values. Response: The Air Quality section in the PSA/DEIS includes a summary and compliance demonstration for all federal, state and local laws, regulations and policies. The permitting agency is identified in the compliance with LORS section. The project requires a PSD permit which would be issued by the SJVAPCD, nonattainment pollutants are regulated under the Nonattainment New Source Review (NNSR) permitting program administered by the SJVAPCD, and the hazardous air pollutant permitting program is administered by the SJVAPCD (hazardous air pollutants are discussed in the Public Health section of the PSA/DEIS). The air quality section provides a summary of the PSD and NNSR permitting findings presented in the SJVAPCD's PDOC, including the District's criteria pollutant modeling analysis. The SJVACPD's PSD analysis, within the PDOC, includes an identification of the pollutants triggering PSD requirements. The BACT and modeled impact analyses are also provided in the PDOC. Emissions have been quantified to demonstrate the nonattainment pollutants subject to NSR requirements. LAER has been addressed and emission credits would be obtained for the applicable pollutants. Class I and Class II areas have been identified and potential impairment to visibility and required AQRV, such as deposition modeling, is included as necessary in the PDOC and discussed in this section. Therefore, the PSA/DEIS analysis includes the analysis of the specific modeling requirements identified in this comment.

Agency – U.S. EPA (TN-66381) 7/26/2012	Comment: (summarized) Mobile Sources The DEIS should identify and quantify the addition of new mobile sources associated with the project, including truck traffic and rail traffic that may result from the transport of coal and petcoke feedstocks and other materials. The expected routes of travel, frequencies, and locations of sensitive receptors should be identified and impacts assessed. See also the comment under Environmental Justice below. Response: The PSA/DEIS includes a detailed analysis of additional mobile sources associated with the project. The analyses included emissions from the transport of both coal and petcoke and the transport of product manufactured at the integrated manufacturing complex. Both transportation alternatives were analyzed. The expected routes of travel, frequency and sensitive receptors were identified. The impacts related to transportation were assessed in several sections of the PSA/DEIS including air quality, public health, and traffic and transportation.
Agency – U.S. EPA (TN-66381) 7/26/2012	Comment: (summarized) Construction Emissions Mitigation The DEIS should include a thorough analysis of impacts from the construction of the proposed project alternatives and emission estimates of all criteria pollutants and diesel particulate matter (DPM). The DEIS should include information regarding health risks associated with vehicle emissions and mobile source air toxics. Response: The PSA/DEIS includes an analysis of impacts from the proposed construction. The analysis in the air quality section includes emission estimates of criteria pollutants. The construction analysis includes an emissions estimate for all emissions sources associated with the project construction including both on-site and offsite sources for both HECA and the OEHI component. Staff reviewed these emissions estimates and required both project applicants to confirm or revise these estimates as staff considered necessary. Additionally, a modeling analysis of the HECA construction criteria pollutant emissions, prepared by the applicant and reviewed by staff, is included in the construction impacts analysis. Air toxics are discussed in the Public Health section of this document.
Agency – U.S. EPA (TN-66381) 7/26/2012	Comment: (summarized) Construction Emissions Mitigation EPA recommends including a Construction Emissions Mitigation Plan (CEMP) for fugitive dust and DPM/fine particulates in the DEIS. The plan should be adopted in the Record of Decision. Response: The PSA/DEIS includes Conditions of Certification **AQ-SC1** through **AQ-SC5** that mitigate construction emissions. **AQ-SC2**

	requires an Air Quality Construction Mitigation Plan (AQCMP) that details the steps that would be taken and the reporting conditions to comply with **AQ-SC3** through **AQ-SC5** that require mitigation of fugitive dust emission and equipment tailpipe emissions, including DPM. In addition, **AQ-SC1** requires the applicant have an onsite construction mitigation manager who would be responsible daily for the implementation and compliance of the mitigation program.
Agency – U.S. EPA (TN-66381) 7/26/2012	Comment: (summarized) Construction Emissions Mitigation EPA recommends the following to reduce diesel particulate matter, hydrocarbons and oxides of nitrogen associated with construction activities. -Minimize use and unnecessary idling -Maintain and tune engines to perform at applicable certification levels and standards. Perform periodic unscheduled visits to ensure compliance. -Prohibit tampering of engines and require adherence to manufacturer's specifications. -Lease new equipment meeting the most stringent applicable State or Federal standards. In general commit to the best available emission control technology. -Include mitigation measures to reduce greenhouse gas emissions. -Use registered particulate traps and other appropriate controls. -Use diesel fuel with a sulfur content of 15 ppm or less -Use control devices. Suitable control device determinations should be made by an independent Licensed Mechanical Engineer. Response: The PSA/DEIS includes Condition of Certification **AQ-SC5** that mitigates emissions of diesel particulate matter, hydrocarbons and oxides of nitrogen from diesel-fueled engines associated with construction activities. **AQ-SC5** requires diesel engines associated with construction to meet the highest tier rating available. Specific exceptions are built in to the requirement. **AQ-SC5** includes additional requirements to ensure the engines are properly maintained and are operated according to state regulations. Operating restrictions specifically include idling restrictions for diesel-fueled engines. Add-on tailpipe emissions control devices are only allowed if equipment with Tier 3 or 4 engines are not available, and these control devices must be verified by the California Air Resources Board or U.S. EPA. Requirements of this condition are designed to mitigate off-road equipment tailpipe emissions to the highest extent possible as long as safety requirements are met and to ensure compliance with LORS.
Agency – U.S. EPA (TN-66381) 7/26/2012	Comment: (summarized) Construction Emissions Mitigation The DEIS should identify the need for a Fugitive Dust Control Plan as required by SJVAPCD. In addition the following is recommended -Stabilize open storage piles and disturbed areas

	-Install wind fencing and phase grading operation where appropriate and use water trucks under windy conditions. -Prevent spillage and limit speeds to 15 mph for non-earthmoving equipment <u>Response</u>: The PSA/DEIS includes conditions of certification mitigating fugitive dust associated with construction emissions. **AQ-SC2** specifically requires the facility to develop an air quality construction mitigation plan (AQCMP) which includes measures to minimize fugitive dust. Condition **AQ-SC3** outlines mitigation measures imposed by the Energy Commission and states any additional mitigation measures imposed by SJVAPCD need to be included in the AQCMP. Condition **AQ-SC4** identifies additional measures to be taken when the required control measures are not adequately mitigating fugitive dust emissions. Requirements are designed to mitigate fugitive dust emissions to the highest extent possible and ensure compliance with LORS.
INTERVENOR: Association of Irritated Residents (AIR)	
Intervenor – AIR (TN-64367) 3/23/2012	<u>Comment</u>: (summarized) “NOx emissions from the CTG/HRSG will be lower…” How much lower? What are the earlier figures? Will the total NOx emissions decrease taking into account the fertilizer plant and related operation? Will using coal as 75 percent of the fuel for the life of the project instead of the first two years increase or decrease criteria air pollutants? Any changes in the fuel transportation should be included in the analysis. How much transportation is associated with the fertilizer plant including deliveries and finished product? How do project emissions change if the rail spur is not built? <u>Response</u>: A preliminary assessment was completed for the original project prior to the submittal of the amended application. According to the preliminary analysis, the annual NOx emissions for the HRSG/CTG were estimated to be 167.86 tons and total NOx stationary source operating emissions were estimated to be 194.89 tons. Total NOx emissions from the HRSG/CTG and coal dryer for the amended application are estimated to be 123.50 tons and total NOx stationary source operating emissions are estimated to be 158.93 tons, roughly 44 and 37 tons below the original project estimates, respectively. The NOx emissions limit from the use of the hydrogen-rich fuel would not be affected by the proportion of coal and petcoke. However, this higher proportion of coal use over the life of the project would be expected to increase the total transportation emissions when considering the entire length of the transportation routes for coal and petcoke. Emissions and impacts from fuel transportation are included in the

	analysis. The facility is proposing two transportation alternatives, and emissions estimates for both alternatives are included in the analysis. The first alternative includes the addition of a rail spur to the project site; the second alternative does not include the new rail spur. With a rail spur, the coal would be delivered to the project site by rail and the fertilizer products would be shipped by rail from the project site. Without a rail spur, coal would be offloaded from the coal trains at an existing transloading facility in Wasco, approximately 26.5 miles from the project site, then shipped by truck the rest of the way to the project site and the fertilizer products would be shipped by truck from the project site. The transportation emissions within the SJVAB would be somewhat lower for the rail spur alterative due to the greater efficiency of shipping by rail rather than truck. **Air Quality Tables 14** and **15** outline criteria pollutant emissions from the two transportation alternatives. Assumptions used to quantify the expected transportation emissions from the two transportation alternatives are provided in the Operational Criteria Pollutant Emissions section of the applicant's amended AFC in Appendix E-3.
Intervenor – AIR (TN-64367) 3/23/2012	<u>Comment</u>: (summarized) Please justify the use of coal as the majority fuel for the life of the project. Is there a reason why the project does not attempt carbon capture with natural gas? <u>Response</u>: The applicant responded to this question posed by the intervenor in the applicant's 4/26/2012 data response.
Intervenor – AIR (TN-66072) 6/29/2012	<u>Comment</u>: (summarized) Please justify why NO_2 data used in the analysis is from the Shafter, Walker Street station and not the Arvin, Bear Mountain station. Please include topography as well as requirements to be conservative to present worst case scenarios in the justification. Please explain how Shafter has the lowest levels of NO_2 emissions and Arvin has the highest. <u>Response</u>: First, the NO_2 concentrations from the Shafter monitoring station are higher to considerably higher than those from Arvin, not lower. A comparison of the last three years of available maximum hourly NO_2 data from Arvin (where monitoring was discontinued after 2010) is shown as follows (in ppm): <u>Arvin</u> <u>Shafter</u> 2008 0.033 0.057 2009 0.051 0.052 2010 0.032 0.074 A comparison of the annual NO_2 monitoring data and the federal 1-

	hour NO_2 concentration (three year average of the 98th percentile of maximum daily values) also clearly shows that the Arvin monitoring station has measured lower, not higher, NO_2 concentrations than the Shafter monitoring station. The NO_2 data used in the impact analysis is from the Shafter-Walker Street (Shafter) station. The Shafter station is the closest station to the proposed site. This station monitors ozone, NO_2 and VOCs which are precursors for ozone. The objective of using this station is to provide background ozone concentrations that are relevant to the nearby project site. The Arvin monitoring site, which monitors ozone and NO_2, is located further from the site than several other monitoring stations, and while it does provide conservative background concentrations for the air basin as a whole for ozone it does not provide a reasonable background for the area immediately surrounding the project site, which is used for the purpose of determining background values for the worst-case near-field impacts. The worst-case air basin conditions are reflected in the non-attainment conditions depicted in **Air Quality Table 4**. The air quality impact analysis does not include the modeling of ozone impacts, so the only pollutant modeled in the impact analysis that the Arvin site monitors is NO_2. The air dispersion modeling analysis, which is inherently conservative due to the dispersion algorithms and the input assumptions regarding NO conversion to NO_2, uses the most representative and conservative site-specific background NO_2 concentrations, which staff has determined to be Shafter, after review of the data from the closest monitoring stations surrounding the project site.
Intervenor – AIR –Tom Franz (TN-66342) 7/27/2012	Why is natural gas not considered an alternative for this project. With the large amount of NOx emitted from burning hydrogen as a fuel and because of the air quality problem in this part of the San Joaquin Valley, explain why there is no option considered to use oxygen only as the combustion air when the hydrogen fuel is burned. In other words, why is it so necessary for HECA to further pollute the air the public breathes in order to save the earth from more GHG emissions? Response: Staff's review of available technologies indicates that the use of oxygen is not technically achievable at this point. The flame temperature that would occur with a hydrogen-rich fuel and oxygen combustion mixture are beyond the current state of CTG materials technology. Other oxygen-based combustion technologies such as

	rocket engine technologies are not yet mature and are not available at the scale of this project. Additionally, the separation of the amount of oxygen necessary would create a large additional parasitic load that could reduce project efficiency significantly. The applicant indicated why natural gas isn't being used as the primary fuel in their 4/26/2012 response.
INTERVENOR: Kern County Farm Bureau	
Intervenor – Farm Bureau (TN-66242) 7/12/2012	Comment: (summarized) The Kern County Farm Bureau is concerned about the contribution of emissions negatively impacting local air quality, where farmers already face the severest regulations and costs for compliance in the world. Response: In terms of air quality, the proposed project faces some of the severest regulations and highest costs for compliance to operate in the San Joaquin Valley Air Basin (SJVAB). Additionally, the proposed project would have to comply with a number of emission reduction mitigation measures, including a Voluntary Emissions Reduction Agreement with the SJVAPCD, to reduce the project's impacts both regionally and locally.
INTERVENOR: Sierra Club	
Intervenor – Sierra Club (TN-66370) 7/27/2012	Comment: (summarized) DOE should consider an enclosed ground flare and a flare recovery system. The EIS must examine air pollution impacts from the rail and truck emissions along the entire 700 mile route. The EIS must consider the impacts to environmental justice areas. The EIS must consider mercury emissions. The EIS must consider the impacts of truck traffic. Response: The SJVAPCD is satisfied that the flare technology selected meets appropriate BACT guidelines as determined in the PDOC. Environmental Justice impacts have been evaluated in this section. The project's mercury emissions, in terms of U.S. EPA MATS rule compliance, are discussed in this section. Please also see the Public Health section of the document for a discussion of the mercury emissions impacts. This section does consider the impacts of the mobile source

	emissions (rail and truck traffic) from the project's fuel feedstock imports and product exports, and the General Conformity analysis would require emissions reductions for NOx within the SJVAB.
PUBLIC COMMENTS	
Public – Trudy Douglass (TN-65878 and TN-66096) 6/20/2012 and 7/4/2012	<u>Comment:</u> I am a teacher and I am very worried about the health of my family and students. My daughter has asthma, a friend who has never smoked has emphysema, and a young friend is one of too many in the valley who has a thy[r]oid tumor. All of these problems are related to living in this valley. <u>Response:</u> This section indicates whether the project would meet all applicable LORS, determines whether significant impacts to criteria pollutants would occur from the project, and recommends measures to reduce these impacts to the maximum extent. Based on this review, the project's criteria pollutant emissions were not determined to cause a significant impact to the health of the surrounding communities. Please see the Public Health section for the air toxics health impact discussion.
Public – Trudy Douglass (TN-65878, TN-66096, and TN-66427) 6/20/2012, 7/4/2012, and 7/27/2012	<u>Comment:</u> (summarized) The people in San Joaquin Valley are working to comply with the EPA regulations, resulting in better air quality in 10 years. A coal/coke gasification factory will erase the progress we have made by burning the dirtiest fuel 24/7. We comply with no burn days, HECA must follow the same rules we do. <u>Response:</u> This IGCC facility would not directly burn the coal and petcoke fuel feedstocks, such as in a traditional coal boiler. The coal/petcoke feedstocks would be transformed in the gasifier to a hydrogen-rich fuel that would be combusted in the gas turbine to make power. The hydrogen-rich fuel would undergo separation and cleaning processes that would remove the vast majority of the remaining sulfur and air toxics compounds before it would be combusted in the gas turbine. This technology would have criteria and air toxics emissions that are well below those from traditional coal fired power plants. Industrial facilities in the San Joaquin Valley must also comply with all local, state, and federal LORS. In addition to EPA regulations, the facility must also comply with the rules and regulations of SJVAPCD and ARB. The federal, state and local agencies together set standards, implement programs for toxics, motor vehicle emissions, locomotives, heavy-duty trucks, ships, off-road diesel equipment, stationary sources, etc. There are only a few rules that directly impact residential emission sources. As noted above, the coal and petcoke feedstock would be gasified and the resulting hydrogen-rich fuel would be cleaned prior to combustion. The

	resulting emissions from the IGCC would meet stringent BACT requirements.
Public – Trudy Douglass (TN-65878, TN-66096, TN-66389, TN-66427, TN-67235) 6/20/2012, 7/4/2012, 7/27/2012, 7/27/2012, and 9/20/2012	Comment: (summarized/combined several similar comments) The HECA site is on and surrounded by prime farm land. It sits at the closed end of the San Joaquin Valley; there is no outlet for the 520 tons of pollutants a year (not including transportation emissions) that the project will emit assuming all of HECA's gasification, storage, sequestration, and transfer processes work perfectly, and this number does not include the millions of tons of CO_2 it is supposed to sequester. This valley is world renowned for the quality, quantity, and diversity of its agricultural products. The project's pollution and particulates each year for 30 years will make our crops and orchards less able to convert the CO_2 to oxygen, will injure our whole ecosystem and may be the death of it. The project will also raise higher our levels of ozone and particles. Response: San Joaquin Valley is subject to federal, state and local air quality regulations designed to achieve healthy air quality. EPA has developed national ambient air quality standards (NAAQS) for pollutants considered harmful to public health and the environment. Primary standards are designed to provide public health protection for sensitive populations. Secondary standards are designed to provide protection against decreased visibility and damage to animals, crops, vegetation and buildings. Many of the secondary standards are the same as the primary standards and there is no secondary standard more stringent than a primary standard. Potential worst-case project emissions were modeled and compared to the NAAQS. Impacts from the project would be mitigated according to the modeling results. The rules and regulations applicable to the San Joaquin Valley were developed to reduce or maintain ambient air quality levels to meet the applicable standards taking into account the specific qualities and needs of the region. California also has adopted CAAQS to further protect these valuable resources.
Public – Trudy Douglass (TN-66096, and TN-66389) 7/4/2012, and 7/27/2012,	Comment: (summarized/combined two similar comments) SCS is using pollution monitoring numbers from Shafter, the closest station to the site. It has the lowest readings in our district, but it does not reveal a valid image of our air quality. The most appropriate baseline for our air pollution and particulate measurements in the district comes from the Arvin/Bear Mountain monitoring station at the end of the valley. Response: Please see the above response to the intervenor AIR's comment on this issue.
Public – Trudy Douglass	Comment: (summarized/combined two similar comments) We have the permanent place as the number 1 spot for the worst air quality

(TN-66245 and TN-66389) 7/12/2012, and 7/27/2012	in the US. If this project goes forth as proposed, we will have higher medical costs from pollution-based diseases: asthma, emphysema, cancer and heart disease, reduced longevity, lower productivity of the people and the land, and vehicle higher fees and fines for our failure to meet EPA particulate standards. Although HECA is responsible, they avoid censure by buying those "magical" air credits with our own tax money to offset their offense against us. This is legal but is it right? <u>Response:</u> The San Joaquin Valley is subject to federal, state and local air quality regulations designed to achieve healthy air quality. The rules and regulations applicable to the San Joaquin Valley were developed to reduce or maintain ambient air quality levels to meet the applicable standards taking into account the specific qualities and needs of the region. Federal and state laws require emission control measures for all pollutants that exceed established standards. The San Joaquin Valley is required to have a plan that outlines the measures they will take to achieve attainment with the federal ambient air quality standards. These plans are referred to as State Implementation Plans (SIPs). The SJVAPCD under the direction and review of the EPA and ARB develops rules and regulations that are designed to improve and maintain air quality so that the San Joaquin Valley is in attainment with these established standards. All projects proposed in SJVAPCD jurisdiction must comply with the rules and regulations in order to be approved. The SJVAPCD's New Source Review (NSR) Rule requires the application of Best Available Control Technology (BACT) to any new or modified emission unit with the potential to emit of 2.0 pounds per day of any criteria pollutant. BACT and other requirements must be applied regardless of offsets. In other words, the purchase and application of emission reduction credits does not equate to project approval. A project must still comply with all established laws, ordinances, regulations and standards (LORS). Additionally, this project has entered into two emissions reduction funding agreements with the District that would fund additional emissions reductions in the San Joaquin Valley as necessary to fulfill General Conformity offset requirements, other District determined CEQA mitigation needs, and a voluntary agreement to address NOx emissions efficiency issues. In comparison, most non-stationary source projects (housing, commercial development, etc.) that may cause large increases in local area emissions have no regulatory requirements to offset their emissions, although in this air basin some of these types of projects do enter into voluntary agreements with the District to fund emissions reductions.
Public – Daniel Bell (TN-66248)	<u>Comment:</u> Are there required offsets for coal transport? <u>Response:</u>

7/16/2012	The mobile source emissions associated with this project would not be directly subject to SJVAPCD permitting and so would not be subject to the SJVAPCD offset rules. However, since this project would be subject to federal approval it would have to comply with the General Conformity rule. The project's operating mobile source emissions within the SJVAB have been determined to exceed the NOx emissions threshold of this rule, so those emissions would have to be offset. The applicant has entered into an emissions reduction funding agreement with the District that would fund additional emissions reductions in the San Joaquin Valley as necessary to fulfill General Conformity offset requirements, other District determined CEQA mitigation needs, and a voluntary agreement to address NOx emissions efficiency issues.
Public – Daniel Bell (TN-66248) 7/26/2012	<u>Comment:</u> Are there required offsets for NOx, SO2, etc? <u>Response:</u> The stationary emissions source offsets, required by SJVAPCD rules and regulations, would be required to be surrendered by the applicant prior to operation of the project. SJVAPCD's NSR rule requires offsets for pollutants with permitted emissions exceeding an established threshold. The project's projected emissions exceed the thresholds for all criteria pollutants, VOC, CO, NOx, SOx, and PM10. Offsets would not be required for CO, because the NSR rule exempts offset requirements for CO if the facility demonstrates the project would not cause a violation to the ambient air quality standards for CO. So all pollutants except CO would be offset. The other emission reductions that would be required for this project would be created by funding provided by the applicant through two mitigation agreements that would fund additional emissions reductions in the San Joaquin Valley as necessary to fulfill General Conformity offset requirements, other District determined CEQA mitigation needs, and a voluntary agreement to address NOx emissions efficiency issues.
Public – Dean Clason (TN-66349) 7/26/2012	<u>Comment:</u> I am opposed to the proposed HECA plant based on the fact that we already have the worst air pollution in the country, and our air basin has no outlet in the southern valley. <u>Response:</u> Comment noted.
Public – Kathleen Parsa (TN-66385) 7/23/2012	<u>Comment:</u> The proposed HECA plant will increase air pollution. It has already been determined that Bakersfield has the worst air quality in the nation. Who wants to make it worse? <u>Response:</u> The PSA/DEIS includes an analysis of the ambient air quality in the

	project area. In addition, the impacts of the proposed project have been modeled and compared to the ambient air quality standards. The project would be required to mitigate emissions to the extent feasible and offset the remaining stationary source operating emissions from the project. The SJVAPCD and Energy Commission staff have both determined that the HECA facility could be built and operated without significantly worsening air quality.
Prior to being an intervenor Public – Chris and John Romanini, et. al. (TN-66382) 7/26/2012	Comment: Kern has the worst air in the nation. Polluted air causes health issues. Should the DOE encourage a demonstration project that will further pollute our air in the interest of global warming? Should not the DOE consider the effects on our local environment first? A small issue is the discretionary decision by local schools that restricts outdoor sports and PE for students when the air quality index (AQI) is above 201, 151, and 101. When HECA operates, will their emissions impacts have the children sitting in the gym more? Response: HECA would incrementally increase pollutants near the project site, and so would have some incremental increases in local pollutants. These impacts have been evaluated and the SJVAPCD and staff have called for mitigation measures to reduce these impacts to the extent feasible. Additionally, HECA's emissions would not be of a magnitude that would affect the AQI estimates or noticeably increase the monitored concentrations from the air monitoring network that is used to quantify the AQI.
Prior to being an intervenor Public – Chris and John Romanini, et. al. (TN-66382) 7/26/2012	Comment: HECA's figures and tables on emissions are difficult to add up. Please state the total PM2.5, PM10, NOx and SO2 emissions per year that HECA will produce. These figures should include both plant (power and chemical) and vehicle (rail and road). Response: The PSA/DEIS includes many tables totaling the calculated emissions from HECA and the OEHI CO_2 EOR component emissions sources. See **Air Quality Table 17** for a summary of annual operating emissions for HECA, including the mobile source emissions, and **Air Quality Table 19** for a summary of the EOR component's operating emissions, including the mobile source emissions. Staff's presentation of these emissions is meant to simplify the presentation and inform the public regarding the projects' emissions sources and emissions totals. Additionally, the applicant docketed revised emissions tables so that the public has the same emissions data updates/clarifications that were provided to staff, the SJVAPCD, and the Sierra Club under confidential cover.

Public – Trudy Douglass, et. al. (TN-66389) 7/27/2012	<u>Comment</u>: The HECA project will put 350 trucks and 200 employees on the road every day with a total of 1100 vehicles a day, going in and out of this factory. (The pollution from these sources is not included with the other pollution totals.) <u>Response:</u> The emissions tables in this section (**Air Quality Tables 14**, **15**, and **17**) do provide the emissions data from the mobile sources noted above. Additionally, the applicant provided mobile source pollutant emissions estimates in the AFC and then provided revised emissions estimates in the data responses to staff data requests that corrected some of the travel distance assumptions used in the mobile source emissions estimate. Finally, staff has recommended mitigation measures meant to reduce the emissions from truck transportation by requiring the use of newer/cleaner trucks (Conditions of Certification **AQ-SC6** and **AQ-SC7**) and by requiring loads to be covered or enclosed to eliminate emissions from spillage (Condition of Certification **AQ-SC10**).
Public – Trudy Douglass, et. al. (TN-66389) 7/27/2012	<u>Comment</u>: Standards for the feedstock must be established. Coke and coal are graded on a sliding scale; can we trust the HECA operators to check for quality? There are many junctures in HECA procedures where toxic waste levels of coke and coal could be added to their feedstock, adding many more heavy metals to their emissions. This kind of manipulation could save a lot of money for some, make a lot of money for others and add significantly to the pollution levels of our air, land, water, and vegetation. <u>Response</u>: HECA would have to meet air pollutant emissions limits, including hazardous air pollutant limits, regardless if they change the source of the coal or petcoke feedstocks. The hazardous metals in the coal, with the exception of very volatile metals (i.e. mercury), would end up encapsulated in the gasification solids. The eventual use or disposal of the gasification solids could be influenced by the metals content of the solids. Please see the Waste Management section for additional discussion on handling and disposal of the gasification solids.
Public – Trudy Douglass, et. al. (TN-66389) 7/27/2012	<u>Comment</u>: An off-site air-monitoring station, at HECA's expense, must be setup down-wind from the factory to monitor pollution levels especially within a 20-mile radius. These readings must be monitored daily by outside consultants, and there must be immediate pre-established consequences for violations. <u>Response</u>: The SJVAPCD operates an extensive network of air quality monitors throughout the San Joaquin Valley air basin to characterize the air quality in the basin. This data is used to determine the attainment status with both the NAAQS and CAAQS

	standards. The SJVAPCD is subject to 40 CFR Part 58 monitoring requirements and guidelines requiring SJVAPVCD to develop a monitoring network plan to ensure an effective system. The plan describes the purpose of each monitor and includes a demonstration that the location and operation of each monitor meets the requirements. The addition of a specific ambient monitor due to a new emissions source is very rarely required unless there is a significant gap in the monitoring network that would jeopardize its effectiveness. Due to mixing and varying chemical and physical properties of the pollutants, the variability of meteorological conditions (wind direction and speed), and the variability of other emissions sources it is very hard to attribute monitored pollutant levels to a specific stationary emissions source. Pollutants do not always behave the same way after they are released into the atmosphere. For example, coarse particles tend to settle more rapidly and travel shorter distances than finer particles; and other pollutants such as NO_2 and VOC chemically transform over time into secondary particulate or ozone. Therefore, it is not always possible to determine from downstream monitors the specific contribution from a source of a specific pollutant. Many times one facility will not affect the readings from downstream monitors. The HECA facility however would be required to measure the direct emissions from the plant by monitoring the emissions in the stack exhaust stream, both with continuous emissions monitoring (CEMS) on the CTG/HRSG for pollutants that can be monitored in this manner and periodic source testing for the other emissions sources. Source testing would be performed by independent contractors who are licensed in the state of California. The source testing contractors would be required to use specific standard source testing methods when testing emissions from project emissions sources. This testing would be required to demonstrate compliance with emissions limits and to check on the accuracy of the CEMS. There would be immediate consequences to the facility if they could not meet emissions limits as determined by the CEMS or if they did not pass a source test.
Public – Arthur Unger (TN-66357) 7/26/2012	<u>Comment</u>: The DEIS should quantify the plant's impacts on local air quality. How much PM10, PM2.5 and ozone from trains and trucks transporting coal from New Mexico, with and without a railroad spur to the plant? How much air pollution from employees driving to the plant, trucks carrying supplies to the plant and trucks taking urea and coal ash from the plant? How much NOx from burning hydrogen? Note that Lamont and Arvin have the worst air in this area of severe non-compliance with NAAQS. <u>Response:</u> The PSA/DEIS quantifies the impacts on local air quality from all the sources indicated in the comment. The emissions from construction, commissioning and operations are all quantified the

	PSA/DEIS. **Air Quality Table 17** summarizes HECA's permitted maximum annual emissions, including the mobile source (truck and train) emissions. **Air Quality Table 21** summarized HECA's modeled ambient air quality impacts. Additional emissions and ambient air quality impact details are presented in several other tables provided in this section.
Public – Brad Bittleston (TN-66348) 7/26/2012	<u>Comment</u>: (summarized) The poor air quality in this valley contributes to the respiratory illnesses of the citizens especially the children. Can't a more remote location somewhere else that can tolerate the changes and negative impacts be a more viable option? <u>Response:</u> Please see the previous comment responses regarding the air quality analysis provided in this section, and please also see the Public Health section for additional health impacts analysis. To some extent, based on the project's purpose, the location of this project is fixed. This project needs a nearby, willing user of CO_2, who would not only accept the CO_2 but would also sequester the CO_2. The applicant has worked out an agreement with Occidental Petroleum to use CO_2 in the Elk Hills Oil field, so any alternative location would need to be in the general proximity of this oil field. Please also see the Alternatives section for a discussion of alternative project locations.

NOTEWORTHY PUBLIC BENEFITS

No air quality related noteworthy public benefits have been identified.

CONCLUSIONS

Staff has made the following preliminary conclusions about HECA:

- Construction impacts would contribute to violations of the ozone, PM10, and PM2.5 ambient air quality standards. Staff recommends Conditions of Certification **AQ-SC1** to **AQ-SC5**, and District Condition of Certification **AQ-1-10** through **AQ-1-19**, to mitigate the project construction-phase impacts to a less than significant level.
- The project's operation would neither cause new violations of any NO_2, CO, or SO_2 ambient air quality standards nor significantly contribute to existing violations for these pollutants. Therefore, the project's direct NO_2, CO, and SO_2 impacts are less than significant.
- HECA's operation would result in a less than significant direct emissions impact under CEQA if HECA complies with staff recommended Conditions of Certification (**AQ-SC6** through **AQ-SC14**) and District required Conditions of Certification (**AQ-1** through **AQ-25**), provides the emissions mitigation funding as agreed with the District for General Conformity and CEQA compliance purposes, and provides the

emission reduction credits to offset the stationary source emissions in quantities recommended by the District (**AQ-1)**. This preliminary finding is contingent that staff's final determination regarding the appropriate interpollutant offset ratio agrees that the District's proposed SOx for PM interpollutant offset ratio, along with the other required mitigation, is adequate to provide a net air quality benefit. The final evaluation of the adequacy of this interpollutant offset ratio will in part be based on the District's response to staff's questions on this issue. Staff will determine, based on that response and the rest of the evidence provided, whether recommended adjustments need to be made to this interpollutant offset ratio for CEQA mitigation purposes. Staff will provide this final determination in the Final Staff Assessment/Final Environmental Impact Statement (FSA/FEIS).

- The proposed project's indirect (or secondary emissions) contribution to existing violations of the ozone and particulate (PM10/PM2.5) ambient air quality standards are likely significant if unmitigated. Therefore, staff recommends **AQ-SC6**, **AQ-SC7**, and **AQ-SC12** to mitigate the project's onsite and offsite transportation emissions to reduce their ozone precursor emissions; District conditions **AQ-1-10** to **AQ-1-19** and staff conditions **AQ-SC9** and **AQ-SC10** mitigate the non-stationary source operating fugitive dust emissions potential to ensure that both the potential ozone and PM10/PM2.5 impacts are mitigated to less than significant over the life of the project.
- The project will continue to operate in compliance with adoption of staff's proposed condition **AQ-SC11** that provides the administrative procedural requirements for project modifications and condition **AQ-SC8** that requires quarterly operations compliance reporting.
- Staff is recommending condition **AQ-SC13** to ensure compliance with the Federal MATS Rule. Staff expects that the District will include MATS compliance conditions in the FDOC that will allow staff to remove this recommended condition.
- Staff condition **AQ-SC14** is included to ensure that the two mitigation agreements the applicant has signed with the District are being complied with, specifically that the required funding has been provided in a timely manner in compliance with these two agreements.
- Staff has reviewed HECA's potential to create offsite odors and has determined that there is the potential for sensitive individuals to perceive odors during worst-case meteorological conditions at or near the project fence line during normal operations. However staff concludes that HECA would not create objectionable odors affecting a substantial number of people, and thus would not have significant odor impacts.
- Staff has considered the environmental justice population surrounding the site (see Socioeconomics Figure 1). Since the project's direct and cumulative air quality impacts have been reduced to less than significant, there is no environmental justice issue for air quality.

OUTSTANDING INFORMATION REQUIRED FOR COMPLETION OF THE FSA/FEIS

Staff requires the following information to complete the FSA/FEIS.

- A revised emissions estimate for HECA that matches the current project description, including but not necessarily limited to: the removal of the ammonia product shipping emissions; and the addition of the limestone fluxant. The revised emissions estimate should include the shipping, handling, and storage emissions from the fluxant and should address the shipping emissions for potential alternative shipping locations for the gasifier solids that have been provided to staff in other data responses.
- The applicant provided Energy Commission staff with updated operating data in an e-mail message for a telephone conference held May 10, 2013. During that conference, the applicant requested Energy Commission staff to prepare a set of written questions on this updated operating data so that they could respond completely to Energy Commission staff needs. These questions cover air quality, carbon sequestration and facility reliability topics. They are listed in the **Carbon Sequestration and Greenhouse Gas Emissions Section** because most of them relate to that topic.
- The District's FDOC that addresses staff's comments on the PDOC, including but not limited to: the need to provide conditions for the limestone fluxant receiving and handling; the addition of federal MATS regulation conditions; and the inconsistencies regarding the SOx for PM interpollutant offset ratio.

RECOMMENDED MITIGATION MEASURES FOR THE EOR PROJECT

Staff makes the following inter-agency request to ensure that the cumulative air quality impacts of HECA and EOR component during construction are less than significant:

The Energy Commission requests that the EOR component CEQA/NEPA responsible agency require construction emission mitigation measures that are as strict or stricter than the measures provided in Staff Conditions **AQ-SC3** through **AQ-SC5**.
The specific mitigation measure requirements requested to be implemented during the EOR component's construction are as follows:

<u>Fugitive Dust Control</u>

Apply the following fugitive dust controls, or other controls as effective:

- Pave the main access roads through the facility to the main EOR site prior to major construction activities.

- All unpaved construction roads and unpaved operation and maintenance site roads, as they are being constructed, shall be stabilized with a non-toxic soil stabilizer or soil weighting agent that can be determined to be both as efficient or more efficient for fugitive dust control as ARB precertified soil stabilizers, and shall not increase any other environmental impacts, including loss of vegetation to areas beyond where the soil stabilizers are being applied for dust control. All other disturbed areas in the project and linear construction sites shall be watered as frequently as necessary during grading; and after active construction activities are complete, the disturbed areas shall be stabilized with a non-toxic soil stabilizer or soil weighting agent, or alternative approved soil stabilizing methods. The frequency of watering can be reduced or eliminated during periods of precipitation.

- No vehicle shall exceed 10 miles per hour on unpaved areas within the construction site or along project linear facilities such as the carbon dioxide injection or well field production pipeline corridors, with the exception that vehicles may travel up to 25 miles per hour on stabilized unpaved roads as long as such speeds do not create visible dust emissions.

- Visible speed limit signs shall be posted at the construction site entrances and along traveled routes.

- All paved roads within the construction site shall be swept at least twice daily (or less during periods of precipitation) on days when construction activity occurs to prevent the accumulation of dirt and debris.

- All soil storage piles and disturbed areas that remain inactive for longer than 10 days shall be covered, or shall be treated with appropriate dust suppressant compounds.

- All vehicles used to transport solid bulk material on public roadways and that have potential to cause visible emissions shall be provided with a cover, or the materials shall be sufficiently wetted and loaded onto the trucks in a manner to provide at least one foot of freeboard.

- Wind erosion control techniques (such as windbreaks, water, chemical dust suppressants, and/or vegetation) shall be used on all construction areas that may be disturbed. Any windbreaks installed to comply with this condition shall remain in place until the soil is stabilized or permanently covered with vegetation.

- The fugitive dust control requirements of SJVAPCD Regulation VIII that are in addition to or more stringent than the requirements of parts A. through N. of this condition shall be identified and performed as necessary for compliance with SJVAPCD Rules and Regulations.

<u>Off-Road Construction Equipment</u>

Apply the following off-road construction equipment engine controls, or other controls as effective:

All off-road diesel construction equipment with a rating of 50 hp or greater used in the construction of this facility shall be powered by the cleanest engines available that also comply the California Air Resources Board's (ARB's) Regulation for In-Use Off-Road Diesel Fleets (California Code of Federal Regulations Title 13, Article 4.8, Chapter 9, Section 2449 et.seq.) and shall include the following with the lowest-emitting engine chosen in each case, as available:

A. All off-road vehicles with compression ignition engines shall comply with the California Air Resources Board's (ARB's) Regulation for In-Use Off Road Diesel Fleets.

B. To meet the highest level of emissions reduction available for the engine family of the equipment, each piece of diesel-powered equipment shall be powered by a Tier 4 engine (without add-on controls) or Tier 4i engine (without add-on controls), or a Tier 3 engine with a post-combustion retrofit device verified for use on the particular engine powering the device by the ARB or the U.S. EPA. For PM, the retrofit device shall be a particulate filter if verified, or a flow-through filter, or at least an oxidation catalyst. For NOx, the device shall meet the latest Mark level verified to be available (as of January 2012, none meet this NOx requirement).

C. For diesel powered equipment where the requirements of Part "B" cannot be met, the equipment shall be equipped with a Tier 3 engine without retrofit control devices or with a Tier 2 or lower Tier engine using retrofit controls verified by ARB or U.S. EPA as the best available control device to reduce exhaust emissions of PM and nitrogen oxides (NOx) unless certified by engine manufacturers that the use of such devices is not practical for specific engine types.

Staff believes that the District will adequately control the EOR component's operating emissions through equipment permitted BACT requirements, emissions offset requirements, and other permit emissions limitations.

PROPOSED CONDITIONS OF CERTIFICATION

Staff recommends the following conditions of certification to address the impacts associated with the construction and operation of HECA. These Conditions include Energy Commission staff's proposed conditions as well as the SJVAPCD proposed Conditions from the PDOC, with appropriate staff proposed verification language added for each condition..

STAFF CONDITIONS OF CERTIFICATION

Staff conditions **AQ-SC1** through **AQ-SC14** are all Energy Commission specific mitigation measures and associated construction and operating conditions. These conditions apply to both the HECA project site, and the associated linear facilities where applicable. The term "CPM" below refers to the Energy Commission's compliance project manager.

AQ-SC1 Air Quality Construction Mitigation Manager (AQCMM): The project owner shall designate and retain an on-site AQCMM who shall be responsible for directing and documenting compliance with Conditions of Certification **AQ-SC3**, **AQ-SC4** and **AQ-SC5** for the entire project site and linear facility construction. The on-site AQCMM may delegate responsibilities to one or more AQCMM Delegates. The AQCMM and AQCMM Delegates shall have full access to all areas of construction on the project site and linear facilities, and shall have the authority to stop any or all construction activities as warranted by applicable construction mitigation conditions. The AQCMM and AQCMM Delegates may have other responsibilities in addition to those described in this condition. The AQCMM shall not be terminated without written consent of the CPM.

Verification: At least 60 days prior to the start of ground disturbance, the project owner shall submit to the CPM for approval, the name, resume, qualifications, and contact information for the on-site AQCMM and all AQCMM Delegates.

AQ-SC2 Air Quality Construction Mitigation Plan (AQCMP): The project owner shall provide an AQCMP, for approval, which details the steps that will be taken and the reporting requirements necessary to ensure compliance with Conditions of Certification **AQ-SC3**, **AQ-SC4,** and **AQ-SC5**.

Verification: At least 60 days prior to the start of any ground disturbance, the project owner shall submit the AQCMP to the CPM for approval. The AQCMP shall include effectiveness and environmental data for the proposed soil stabilizer's use on all conditions specific to the site, including any information related to US EPA or ARB approvals or certifications for such use. The CPM will notify the project owner of any necessary modifications to the plan within 30 days from the date of receipt.

AQ-SC3 Construction Fugitive Dust Control: The AQCMM shall submit documentation to the CPM in each Monthly Compliance Report (MCR) that demonstrates compliance with the following mitigation measures for the purposes of minimizing fugitive dust emission creation from construction activities and preventing all fugitive dust plumes from leaving the project boundary. Any deviation from the AQCMP mitigation measures shall require prior CPM notification and approval.

A. The main access roads through the facility to the power block areas will be paved prior to initiating construction in the main power block area, and delivery areas for operations materials (chemicals, replacement parts, etc.) will be paved prior to taking initial deliveries.

B. All unpaved construction roads and unpaved operation and maintenance site roads, as they are being constructed, shall be stabilized with a non-toxic soil stabilizer or soil weighting agent that can be determined to be both as efficient or more efficient for fugitive dust control as ARB precertified soil stabilizers, and shall not increase any other environmental impacts, including loss of vegetation to areas beyond where the soil stabilizers are being applied for dust control. All other disturbed areas in the project and linear construction sites shall be watered as frequently as necessary during grading (consistent with Biology Conditions of Certification that address the minimization of standing water); and after active construction activities are complete, the disturbed areas shall be stabilized with a non-toxic soil stabilizer or soil weighting agent, or alternative approved soil stabilizing methods, in order to comply with the dust mitigation objectives of Condition of Certification **AQ-SC4**. The frequency of watering can be reduced or eliminated during periods of precipitation.

C. No vehicle shall exceed 10 miles per hour on unpaved areas within the construction site or along project linear facilities such as the carbon dioxide pipeline corridor, with the exception that vehicles may travel up to

25 miles per hour on stabilized unpaved roads as long as such speeds do not create visible dust emissions.

D. Visible speed limit signs shall be posted at the construction site entrances and along traveled routes.

E. All construction equipment vehicle tires shall be inspected and washed as necessary to be cleaned free of dirt prior to entering paved roadways.

F. Gravel ramps of at least 20 feet in length must be provided at the tire washing/cleaning station.

G. All unpaved exits from the construction site shall be graveled or treated to prevent track-out to public roadways.

H. All construction vehicles shall enter the construction site through the treated entrance roadways, unless an alternative route has been submitted to and approved by the CPM.

I. Construction areas adjacent to any paved roadway shall be provided with sandbags or other equivalently effective measures to prevent run-off to roadways, or other similar run-off control measures as specified in the Storm Water Pollution Prevention Plan (SWPPP), only when such SWPPP measures are necessary so that this condition does not conflict with the requirements of the SWPPP.

J. All paved roads within the construction site shall be swept, using a PM10-efficient street sweeper that would meet the requirements of SJVAPCD Rule 8061, at least twice daily (or less during periods of precipitation) on days when construction activity occurs to prevent the accumulation of dirt and debris.

K. At least the first 500 feet of any paved public roadway exiting the construction site or exiting other unpaved roads en route from the construction site or construction staging areas shall be swept at least twice daily (or less during periods of precipitation) on days when construction activity occurs or on any other day when dirt or runoff resulting from the construction site activities is visible on the public paved roadways.

L. All soil storage piles and disturbed areas that remain inactive for longer than 10 days shall be covered, or shall be treated with appropriate dust suppressant compounds.

M. All vehicles used to transport solid bulk material on public roadways and that have potential to cause visible emissions shall be provided with a cover, or the materials shall be sufficiently wetted and loaded onto the trucks in a manner to provide at least one foot of freeboard.

N. Wind erosion control techniques (such as windbreaks, water, chemical dust suppressants, and/or vegetation) shall be used on all construction areas that may be disturbed. Any windbreaks installed to comply with this condition shall remain in place until the soil is stabilized or permanently covered with vegetation.

O. The fugitive dust control requirements of SJVAPCD Regulation VIII that are in addition to or more stringent than the requirements of parts A. through N. of this condition shall be identified in the AQCMP (**AQ-SC2**), and performed as necessary for compliance with SJVAPCD Rules and Regulations and Conditions **AQ-1-10** through **AQ-1-19**.

Verification: The AQCMM shall provide to the CPM in the monthly compliance report (MCR):

A. a summary of all actions taken to maintain compliance with this condition;

B. copies of any complaints filed with the District related to project construction; and

C. any other documentation deemed necessary by the CPM or AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner's discretion.

AQ-SC4 Dust Plume Response Requirement: The AQCMM shall monitor all construction activities for visible dust plumes. Observations of visible dust plumes that have the potential to be transported: (A) off the project site and within 400 feet upwind of any regularly occupied structures not owned by the project owner, or (B) 200 feet beyond the centerline of the construction of linear facilities indicate that existing mitigation measures are not resulting in effective mitigation. The AQCMP shall include a section detailing how the augmented mitigation measures will be accomplished within the time limits specified in Steps 1 through 3, below. The AQCMM or Delegate shall implement the following procedures for augmented mitigation measures in the event that such visible dust plumes are observed:

Step 1: The AQCMM shall direct more intensive application of the existing mitigation methods within 15 minutes of making such a determination.

Step 2: The AQCMM shall direct implementation of additional methods of dust suppression if Step 1, specified above, fails to result in adequate mitigation within 30 minutes of the original determination.

Step 3: The AQCMM shall direct a temporary shutdown of the activity causing the emissions if Step 2, specified above, fails to result in effective mitigation within one hour of the original determination. The activity shall not restart until the AQCMM is satisfied that appropriate additional mitigation or other site conditions have changed so that visual dust plumes will not result upon restarting the shutdown source. The owner/operator may appeal to the CPM any directive from the AQCMM to shut down an activity. However, the shutdown goes into effect within one hour of the original determination unless overruled by the CPM before that time

Verification: The AQCMM shall provide to the CPM in the MCR:

A. a summary of all actions taken to maintain compliance with this condition;

B. copies of any complaints filed with the District and provided to the project owner related to project construction; and

C. any other documentation deemed necessary by the CPM or AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner's discretion.

AQ-SC5 Diesel-Fueled Engine Control: The AQCMM shall submit to the CPM, in the MCR, a table that demonstrates compliance with the AQCMP mitigation measures for purposes of controlling diesel construction-related combustion emissions. Any deviation from the AQCMP mitigation measures requires prior CPM notification and approval.

All off-road diesel construction equipment with a rating of 50 hp or greater used in the construction of this facility shall be powered by the cleanest engines available that also comply the California Air Resources Board's (ARB's) Regulation for In-Use Off-Road Diesel Fleets (California Code of Federal Regulations Title 13, Article 4.8, Chapter 9, Section 2449 et.seq.) and shall be included in the Air Quality Construction Mitigation Plan (AQCMP) required by **AQ-SC2**. The AQCMP measures shall include the following with the lowest-emitting engine chosen in each case, as available:

A. All off-road vehicles with compression ignition engines shall comply with the California Air Resources Board's (ARB's) Regulation for In-Use Off Road Diesel Fleets.

B. To meet the highest level of emissions reduction available for the engine family of the equipment, each piece of diesel-powered equipment shall be powered by a Tier 4 engine (without add-on controls) or Tier 4i engine (without add-on controls), or a Tier 3 engine with a post-combustion retrofit device verified for use on the particular engine powering the device by the ARB or the U.S. EPA. For PM, the retrofit device shall be a particulate filter if verified, or a flow-through filter, or at least an oxidation catalyst. For NOx, the device shall meet the latest Mark level verified to be available (as of January 2012, none meet this NOx requirement).

C. For diesel powered equipment where the requirements of Part "B" cannot be met, the equipment shall be equipped with a Tier 3 engine without retrofit control devices or with a Tier 2 or lower Tier engine using retrofit controls verified by ARB or U.S. EPA as the best available control device to reduce exhaust emissions of PM and nitrogen oxides (NOx) unless certified by engine manufacturers or the on-site AQCMM that the use of such devices is not practical for specific engine types. For purposes of this condition, the use of such devices is "not practical" for the following, as well as other, reasons.

1. There is no available retrofit control device that has been verified by either the California Air Resources Board or U.S. EPA to control the engine in question and the highest level of available control using retrofit or Tier 1 engines is being used for the engine in question; or

2. The use of the retrofit device would unduly restrict the vision of the operator such that the vehicle would be unsafe to operate because the device would impair the operator's vision to the front, sides, or rear of the vehicle, or

3. The construction equipment is intended to be on site for 10 work days or less

D. The CPM may grant relief from a requirement in Part "B" or "C" if the AQCMM can demonstrate a good faith effort to comply with the requirement and that compliance is not practical.

E. The use of a retrofit control device may be terminated immediately, provided that: (1) the CPM is informed within 10 working days following such termination; (2) a replacement for the construction equipment in question, which meets the level of control required, occurs within 10 work days following such termination of the use (if the equipment would be needed to continue working at this site for more than 15 work days after the use of the retrofit control device is terminated); and (3) one of the following conditions exists:

1.. The use of the retrofit control device is excessively reducing the normal availability of the construction equipment due to increased down time for maintenance, and/or reduced power output due to an excessive increase in back pressure.

2. The retrofit control device is causing or is reasonably expected to cause engine damage.

3. The retrofit control device is causing or is reasonably expected to cause a substantial risk to workers or the public.

4. Any other seriously detrimental cause which has the approval of the CPM prior to implementation of the termination.

F. All equipment with engines meeting the requirements above shall be properly maintained and the engines tuned to the engine manufacturer's specifications.

G. Construction equipment will employ electric motors when feasible.

H. If the requirements detailed above cannot be met, the AQCMM shall certify that a good faith effort was made to meet these requirements and this determination must be approved by the CPM.

I. All off-road diesel-fueled engines used in the construction of the facility shall have clearly visible tags issued by the on-site AQCMM showing that the engine meets the conditions set forth herein.

J. All diesel heavy construction equipment shall not idle for more than five minutes. Vehicles that need to idle as part of their normal operation (such as concrete trucks) are exempted from this requirement.

Verification: The AQCMM shall include in the MCR the following to demonstrate control of diesel construction-related emissions:

A. A summary of all actions taken to control diesel construction related emissions;

B. A table listing all heavy equipment used on site during that month, showing the tier level of each engine and the basis for alternative compliance with this condition for each engine not meeting Part "B" requirements. The MCR shall identify the owner of the equipment and contain a letter from each owner indicating that the equipment has been properly maintained; and

C. Any other documentation deemed necessary by the CPM and the AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner's discretion.

AQ-SC6 The project owner, when purchasing, leasing or renting dedicated on-road or off-road vehicles for feedstock or product transport (including sulfur and gasifier solids) shall obtain vehicles that meet California on-road vehicle emission standards or appropriate U.S. EPA/California off-road engine emission standards for the latest model year available when obtained.

Verification: At least 60 days prior to the start of commercial operation, the project owner shall submit to the CPM a copy of a plan that identifies the sizes and types of on-site vehicles and equipment and the associated vehicle and equipment purchase orders and contracts and/or purchase schedule. The plan shall be updated every other year to indicate any new vehicles or equipment purchased since the previous plan submittal. The plan shall be submitted in the Annual Compliance Report.

AQ-SC7 The project owner, when contracting for haul trucks that will be hauling feedstocks or products (including sulfur and gasification solids) to and from the project site shall require that all such haul trucks are licensed in the state of California and meet or exceed 2010 model year emissions standards.

Verification: The project owner shall provide a copy of the agreement with each trucking company used for hauling feedstocks and products to and from the site to the CPM for approval that demonstrates compliance with this condition at least 30 days before any feedstock or product hauling is performed by the trucking company.

AQ-SC8 The project owner shall submit to the CPM Quarterly Operations Reports and an annual compliance report that include operational and emissions information as necessary to demonstrate compliance with this condition of certification. The Quarterly Operations Report shall specifically note or highlight any incidences of noncompliance. The Quarterly Operations Report for the fourth quarter shall also include the annual compliance report.

<u>Verification:</u> The project owner shall submit quarterly operation reports to the CPM, and District if requested, no later than 30 days following the end of each calendar quarter. This information shall be maintained on site for a minimum of five years and shall be provided to the CPM and District personnel upon request.

AQ-SC9 The project owner shall provide a site operations dust control plan, including all applicable fugitive dust control measures identified in **AQ-SC3** that would be applicable to reducing fugitive dust from ongoing operations that:

A. Describes the active operations and wind erosion control techniques such as windbreaks and chemical dust suppressants, including their ongoing maintenance procedures, that shall be used on areas that could be disturbed by vehicles or wind anywhere within the project boundaries and linear facilities; and

B. Identifies the location of signs throughout the facility that will limit traveling on unpaved surfaces. In addition, vehicle speed shall be limited to no more than 10 miles per hour on these unpaved surfaces, with the exception that vehicles may travel up to 25 miles per hour on stabilized unpaved surfaces as long as such speeds do not create visible dust emissions.

C. Identifies the street sweeping frequency and extent for the onsite and the project affected adjacent offsite paved roads, including the use of a PM10-efficient street sweeper that would meet the requirements of SJVAPCD Rule 8061.

The site operations fugitive dust control plan shall include the use of durable non-toxic soil stabilizers on all regularly used unpaved surfaces and disturbed off-road areas, or alternative methods for stabilizing disturbed off-road areas, within the project boundaries and linear facilities, and shall include the inspection and maintenance procedures that will be undertaken to ensure that the unpaved surfaces remain stabilized. The soil stabilizer used shall be a non-toxic soil stabilizer or soil weighting agent that can be determined to be as efficient as or more efficient for fugitive dust control as ARB precertified soil stabilizers, and shall not increase any other environmental impacts including loss of vegetation or adverse habitat impact.

The fugitive dust controls shall meet the performance requirements of condition **AQ-SC4**. The performance requirements of **AQ-SC4** shall also be included in the operations dust control plan.

<u>Verification:</u> At least 60 days prior to the start commercial operation, the project owner shall submit to the CPM for review and approval a copy of the plan that identifies the dust and erosion control procedures, including effectiveness and environmental data for the proposed soil stabilizer, that will be used during operation of the project and that identifies all locations of the speed limit signs. At least 60 days after the beginning of commercial operation, the project owner shall provide to the CPM a report identifying the locations of all speed limits signs, and a copy of the project employees and contractor training material that clearly identifies that project employees and contractors are aware of these procedures and that they are required to comply with all dust and erosion control procedures and on-site speed limits. The project owner shall also notify the CPM and receive prior approval before changing approved dust suppression methods.

AQ-SC10 The project owner shall use the following measures to reduce fugitive dust from railcar and truck loads serving the project site.

<u>Railcars</u>

The project owner shall ensure that a surface stabilizing compound (surfactant or water), railcars with adequate freeboard, railcars with other dust mitigation design features, or a combination of these methods are used so that: 1) coal dust is not emitted in amounts that are visible by human observation outside of the coal mine property, 2) coal and produced product of any size is not released in visible quantities alongside the rail spur from the main rail line to the project site, and 3) produced product dust is not emitted in amounts that are visible by human observation at the project site or elsewhere along the entire rail transportation route. The project owner shall inspect the length of the rail spur once a month, and shall also inspect the rail spur within a day of receiving related complaints from the public or as requested by the CPM. These inspections shall be photo documented and shall include detailed information when coal or produced product losses are discovered along the rail spur and shall detail the mitigation measures applied to remove any such material found and the measure used to control future losses along the rail spur. This measure is not required if fully enclosed railcars are used for coal or produced product transport.

<u>Trucks</u>

The project owner shall ensure that all bulk material truck loads to and from the project site are either fully enclosed or covered. The project owner shall inspect the truck access/egress route within a day of receiving any complaints of truck load spills from the public or as requested by the CPM. These inspections shall be photo documented and shall include detailed information when truck load spills are discovered along the truck route and detail the mitigation measures applied to remove the spilled material that is found and the measure used to control future truck load losses along the truck route. This measure is not required if only fully enclosed trucks are used for all bulk material transport into and out of the project site.

<u>**Verification:**</u> The project owner shall submit the monthly rail spur and any required truck route inspection reports in the Quarterly Operations Reports (**AQ-SC8**).

The applicant shall provide the method of initial railcar emissions control, including the specifications of the surface stabilizing compound if used, to the CPM for approval at least 60 days prior to shipping the first load of coal to the site. These records shall be maintained onsite for a minimum of two years and shall be provided to the CPM and District personnel upon request. For the purposes of this condition for rail transport the term “coal” means coal or petroleum coke, and “produced product” and “bulk materials” are any materials transported where such materials can be lost through wind erosion or can be spilled from loaded rail cars or trucks due to bumps or turns, as opposed to catastrophic accidents.

AQ-SC11 The project owner shall provide to the CPM copies of all District issued Authority-to-Construct (ATC) and Permit-to-Operate (PTO) documents for the facility. The project owner shall submit to the CPM for review and approval any modification proposed by the project owner to any federal air permit for the project. The project owner shall submit to the CPM any modification to any federal air permit proposed by the District or U.S. Environmental Protection Agency (U.S. EPA), and any revised federal air permit issued by the District or U.S. EPA, for the project.

Verification: The project owner shall submit any ATC, PTO, or proposed federal air permit modifications to the CPM within 5 working days of either: 1) submittal by the project owner to an agency, or 2) receipt of proposed modifications from an agency. The project owner shall submit all modified ATC/PTO documents and all federal air permits to the CPM within 15 days of receipt.

AQ-SC12 The project owner shall provide the following to mitigate locomotive engine emissions:

Line Haul Locomotives

The project owner shall complete an agreement with the rail line operator that requires the use of Tier 3 or better line haul locomotive engines for all rail transportation to and from the project site until the end of 2019, and shall require the use of Tier 4 engines thereafter. These agreements may be made in two parts with the first Tier 3 agreement due prior to the receipt of any operating coal or petroleum coke feedstock materials by rail; and the second Tier 4 agreement due by October of 2019.

Onsite Switch Locomotives

Onsite Switch Locomotives shall meet Tier 4 locomotive or Tier 4 Nonroad emissions standards, depending on which standard applies.

Verification: The project owner shall provide a copy of the agreement(s) with the rail line operator that demonstrates compliance with this condition to the CPM for approval within the specified due dates required by this condition. The project owner shall submit the engine’s specifications of the proposed project owner owned onsite switch locomotive(s) engine to the CPM for approval at least 30 days prior to purchasing or leasing the switch locomotive(s), or if the switch locomotive will be owned and operated by a third party the project owner shall provide the engine specifications to the CPM for approval at least 30 days prior to the switch locomotive being transported to the site.

AQ-SC13 The project owner shall document compliance with federal Mercury and Air Toxics Standards (MATS). The project owner shall provide source testing data or other U.S. EPA approved testing results that demonstrate compliance with the MATS (40 CFR Subpart UUUUU Table 1). The mercury emissions control system shall be in operation at all times when the gasifier and coal dryer are operating and otherwise when there is any potential for coal or petcoke derived mercury emissions. The project owner shall develop a plan to monitor the activated carbon mercury emissions control systems to identify proper carbon change out frequency to avoid saturation and emissions break through. The testing shall meet test plan preparation, notification, and test report requirements as specified in applicable provisions of Conditions of Certification **AQ-1**, **AQ-5**, **AQ-6**, **AQ-9**, and **AQ-11**.

Verification: The project owner shall submit to the CPM a summary of the results of tests required prior to commercial operation that demonstrate compliance with the appropriate 40 CFR Subpart UUUUU Table 1 emissions standards. no later than 60 days after testing is complete, and shall submit subsequent compliance demonstration data no later than 60 days after the testing is complete that meets the compliance demonstration frequency requirements of 40 CFR Subpart UUUUU. The project owner shall provide a monitoring plan for the mercury emissions control systems to the CPM for approval at least 60 days prior to operating these control systems.

AQ-SC14 The project owner shall document compliance with the two mitigation funding agreements that they have signed with the District, specifically providing proof of funding the mitigation amounts as required in the two SJVAPCD Board-approved agreements.

Verification: The project owner shall submit to the CPM a letter from the APCO acknowledging that the funding for the two mitigation agreements has been provided as required by the two SJVAPCD Board-approved mitigation agreements within 15 days of the agreement timeline requirements to receive the funding.

DISTRICT PRELIMINARY DETERMINATION OF COMPLIANCE CONDITIONS (SJVAPCD 2013a)

The SJVACPD permits each permit unit separately, which causes duplication of conditions and verifications. In total there are 1,179 conditions in the PDOC. Staff has compiled the SJVAPCD conditions by permit unit into aggregated AQ conditions, removing the general facility conditions contained in each permit unit's conditions, retaining the District condition numbers and providing less redundant verifications, as shown in the following referencing table.

Staff Condition	District Conditions
AQ-1	Contains nineteen General Facility Conditions, including all of the conditions not listed below in the specific permit unit conditions, except the two conditions that required finalization of the mitigation agreements prior to publication of the FDOC, which were removed since these two

	mitigation agreements have been finalized and approved by the SJVAPCD Governing Board.
AQ-2	Permit Unit S-7616-17-0 – Conditions 8 through 35
AQ-3	Permit Unit S-7616-18-0 – Conditions 8 through 35
AQ-4	Permit Unit S-7616-19-0 – Conditions 8 through 33
AQ-5	Permit Unit S-7616-20-0 – Conditions 8 through 32
AQ-6	Permit Unit S-7616-21-0 – Conditions 8 through 30
AQ-7	Permit Unit S-7616-22-0 – Conditions 8 through 36
AQ-8	Permit Unit S-7616-23-0 – Conditions 11 through 73
AQ-9	Permit Unit S-7616-24-0 – Conditions 8 through 19
AQ-10	Permit Unit S-7616-25-0 – Conditions 11through 45
AQ-11	Permit Unit S-7616-26-0 – Conditions 11through 91
AQ-12	Permit Unit S-7616-27-0 – Conditions 7, 9 through 20
AQ-13	Permit Unit S-7616-28-0 – Conditions 7, 9 through 20
AQ-14	Permit Unit S-7616-29-0 – Conditions 7, 9 through 20
AQ-15	Permit Unit S-7616-30-0 – Conditions 11 through 51
AQ-16	Permit Unit S-7616-31-0 – Conditions 11 through 62
AQ-17	Permit Unit S-7616-32-0 – Conditions 11 through 62
AQ-18	Permit Unit S-7616-33-0 – Conditions 11 through 63
AQ-19	Permit Unit S-7616-34-0 – Conditions 8 through 35
AQ-20	Permit Unit S-7616-35-0 – Conditions 8 through 42
AQ-21	Permit Unit S-7616-36-0 – Conditions 8 through 21
AQ-22	Permit Unit S-7616-37-0 – Conditions 8 through 34
AQ-23	Permit Unit S-7616-38-0 – Conditions 8 through 25
AQ-24	Permit Unit S-7616-39-0 – Conditions 8 through 25
AQ-25	Permit Unit S-7616-40-0 – Conditions 8 through 25

The following are the aggregated District conditions from the PDOC[19]:

AQ-1 The following conditions are general facility conditions that apply to the facility as a whole:

1. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

[19] Please note that acronyms provided in the District conditions may not be defined within the conditions, but they are provided in the acronym list at the end of this section.

2. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

3. Prior to initial operation of S-7616-23, -25, -26, -30, -31, -32, -33, and -35, permittee shall provide NOx emission reduction credits for the following quantity of emissions: 1st quarter: 74,201 lb, 2nd quarter: 74,201 lb, 3rd quarter: 74,201 lb, and fourth quarter: 74,201 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

4. Prior to initial operation of S-7616-17, -18, -19, -20, -22, -23, -25, -26, -27, -28, -29, -30, -31, -32, -33, -34, -36, -37, -38, -39, and -40, permittee shall provide PM10/PM2.5 emission reduction credits for the following quantity of emissions: 1st quarter: 39,538 lb, 2nd quarter: 39,538 lb, 3rd quarter: 39,538 lb, and 4th quarter: 39,538 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10/PM2.5 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

5. Prior to initial operation of S-7616-23, -25, -26, -30, -31, -32, and -33, permittee shall provide SOx emission reduction credits for the following quantity of emissions: 1st quarter: 1,170 lb, 2nd quarter: 1,170 lb, 3rd quarter: 1,170 lb, and 4th quarter: 1,170 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

6. Prior to initial operation of S-7616-21, -23, -24, -25, -26, -30, -31, -32, and -33, permittee shall provide VOC emission reduction credits for the following quantity of emissions: 1st quarter: 13,792 lb, 2nd quarter: 13,792 lb, 3rd quarter: 13,792 lb, and 4th quarter: 13,792 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). [District Rule 2201]

7. ERC certificate numbers C-1058-2, C-1058-5, S-3275-5, S-3273-2, S-3305-1, S-3557-1, and/or S-3605-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Determination of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Determination of Compliance. [District Rule 2201]

8. Permittee shall provide the District at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. [District Rule 4001 and 40 CFR 60.8]

9. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

10. An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

11. Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

12. An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

13. Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

14. Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

15. Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20 percent opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

16. Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20 percent opacity. [District Rule 8011 and 8071]

17. On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips for vehicles with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20 percent opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

18. Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

19. Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

Verification: The following verification requirements apply to applicable general facility conditions:

The project owner shall submit to both the District and CPM the Federally Mandated Operating Permit application and Acid Rain Program permit application within twelve months of commencing operation. (Conditions **AQ 1-1** and **-2**)The project owner shall submit to both the District and CPM records showing that the project's offset requirements have been met prior to initiating operation. (Conditions **AQ 1-3** through **-6**)

The project owner shall submit to the CPM a list of the ERC certificates and quantities surrendered to the District within 30 days of their surrender. The project owner shall request any changes to the ERC certificates listed in this condition at least 30 days prior to their surrender date. If the CPM, in consultation with the District, approves a substitution or modification, the CPM shall file a statement of the approval with the commission docket and mail a copy of the statement to every person on the post-certification mailing list. The CPM shall maintain an updated list of approved ERCs for the project. The initial table of the approved list of ERCs is as follows: (Condition **AQ-1-7**).

HECA Approved ERC List

ERC Certificate	Pollutant	1st Quarter lbs	2nd Quarter lbs	3rd Quarter lbs	4th Quarter lbs
S-3273-2	NOx	120,500	120,500	120,500	120,500
C-1058-2	NOx	10,100	10,100	10,100	10,100
S-3275-5	SOx	42,000	42,000	42,000	42,000
C-1058-5	SOx	24,500	24,500	24,500	24,500
S-3305-1	VOC	14,625	14,625	14,625	14,625
S-3557-1	VOC	11,437	11,438	11,438	11,437
S-3605-1	VOC	7,937	7,938	7,938	7,937

The project owner shall provide the District and the CPM at least 30 days prior notice of any performance test, except as specified under other District Conditions, and the project owner shall submit source test plans to the District for approval and the CPM for review at least 15 days prior to testing (Condition **AQ 1-8**).

The project owner shall provide the Dust Control Plan required under this condition, which will be coordinated with the plan and dust control requirements of staff conditions **AQ-SC2** and **AQ-SC3**, to the CPM and APCO at the same time, and if desired as part of plan required under staff condition **AQ-SC2**. (Condition **AQ-1-10**)

The project owner shall provide a summary of the fugitive dust mitigation measures performed as necessary to comply with this condition and staff condition AQ-SC9 during facility operation in the Annual Compliance Reports (**AQ-SC8**). During construction the facility will comply with the mitigation measures and reporting/recordkeeping requirements of conditions staff conditions **AQ-SC2** through **AQ-SC4.** (Conditions **AQ-1-10** to **-19**)

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-1** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-1-9** through **-19**)

AQ-2 The following conditions cover permit unit S-7616-17-0.
RAIL UNLOADING AND TRANSFER SYSTEM FOR THE HANDLING OF COAL, INCLUDING: ENCLOSED RAIL UNLOADING BUILDING SERVED BY BAGHOUSE DUST COLLECTOR AND DUST SUPPRESSION SPRAY SYSTEM, WITH RAILCAR UNLOADING STATION, RAIL UNLOADING BIN(S), BELT FEEDER(S), RAIL UNLOADING CONVEYOR(S) ENCLOSED IN UNLOADING TUNNEL (SERVED BY A DUST COLLECTOR) THAT TRANSFERS MATERIAL TO TOWER #1 SERVING FEEDSTOCK STORAGE (S-7616-19)

8. Unloading hopper shall be equipped with water/additive misting system, which shall be employed as needed to control dust emissions during unloading. [District Rule 2201]

9. Operation shall include the following dust collectors serving the following operation(s): rail unloading station. [District Rule 2201]

10. Railcar unloading station shall include water spray nozzles that shall be automatically activated at or prior to unloading as necessary to prevent visible emissions. [District Rule 2201]

11. All conveyors and crushers shall be fully enclosed and shall vent only to dust collectors. [District Rule 2201]

12. All feedstock processing and conveying equipment, feedstock storage systems, and feedstock transfer and loading systems shall be dust-tight (to prevent visible emissions in excess of 5 percent opacity) and shall vent only to dust collectors. [District Rules 2201, 4001, and 40 CFR 60.254]

13. Each dust collector shall be equipped with dust-tight (to prevent visible emissions in excess of 5 percent opacity) provisions to return collected material to process equipment. [District Rules 2201, 4001, and 40 CFR 60.254]

14. Each dust collector shall be equipped with operational differential pressure indicators, and during fabric collector operation read in the proper range specified by the manufacturer. [District Rule 2201]

15. The differential pressure across each compartment of the dust collectors shall be checked and the results recorded quarterly. If the differential pressure across each compartment of the dust collectors is not within the proper range specified by the manufacturer, corrective action is required prior to further operation of the equipment. Corrective action means that the cause of the improper pressure differential is corrected before operation of the equipment is resumed. [District Rule 2201]

16. Each dust collector shall automatically activate whenever process equipment served is activated. [District Rule 2201]

17. Enclosure dust suppression system water spray nozzles shall automatically operate when railcar unloading is occurring. [District Rule 2201]

18. Material shall not be conveyed or crushed unless ventilation system and dust collectors are operating and functioning properly. [District Rule 2201]

19. Permittee shall maintain daily records of the hours of operation and weight of material processed by this operation, and records shall be made available for District inspection upon request. [District Rule 2201]

20. Airflow for the following dust collector(s) shall not exceed: rail unloading station: 20,000 cfm. [District Rule 2201]

21. Particulate matter emissions from the dust collectors shall not exceed 0.001 grains/dscf in concentration. [District Rules 2201, 4001, and 40 CFR 60.254]

22. PM10 emissions shall not exceed any of the following emissions for the following operation(s): rail unloading station: 4.1 lb/day. [District Rule 2201]

23. PM10 emissions shall not exceed any of the following emissions for the following operation(s): rail unloading station: 267 lb/yr. [District Rule 2201]

24. The maximum process rates of material on a weight basis shall not exceed any of the following: rail unloading station: 6,107 ton/day. [District Rule 2201]

25. The maximum process rates of material on a weight basis shall not exceed any of the following: rail unloading station: 396,955 ton/yr. [District Rule 2201]

26. Dust collector filters shall be completely inspected annually while not in operation for tears, scuffs, abrasives or holes which might interfere with PM collection efficiency and shall be replaced as needed. [District Rule 2201]

27. Visible emissions from the operation shall be checked and the project owner shall record results quarterly. If visible emissions are observed, corrective action is required prior to further loading. Corrective action means that visible emissions are eliminated before next loading event. [District Rule 2201]

28. Records of dust control device maintenance, inspection, and repairs shall be maintained. The records shall include identification of equipment, date of inspection, corrective action taken, and identification of individual performing inspection. [District Rule 2201]

29. Testing for particulate matter concentration for each dust collector shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 12 calendar months of the date the previous performance test was required to be completed thereafter. If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(1), 40 CFR 60.8]

30. Testing for compliance with particulate matter concentration limit shall be conducted using EPA method 5. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin. A minimum of three valid test runs are needed to comprise a PM performance test. [District Rule 4001 and 40 CFR 60.255(1) and 60.257(5)(i)]

31. Testing for the opacity standards for the operations shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 90 operating days of the date the previous performance test was required to be completed thereafter. If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(2), 40 CFR 60.8]

32. Source testing to determine opacity as required by 40 CFR Part 60, Subpart Y shall be conducted using EPA method 9. [District Rule 4001 and 40 CFR 60.257(a)]

33. The permittee shall conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible. [District Rule 4001 and 40 CFR 60.257]

34. Permittee shall maintain a logbook (written or electronic) with the records specified in 40 CFR Subpart 60.258(a) on-site and make it available upon request. [District Rule 4001 and 40 CFR 60.258]

35. Permittee shall conduct testing for compliance with the particulate matter concentration limit and particulate matter emissions limit within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility. [District Rule 4001 and 40 CFR 60.258(c), 40 CFR 60.8]

Verification: The following verification requirements apply to applicable conditions for permit unit S-7616-17-0:

The project owner shall provide a summary of: 1) operations throughput and annual emissions estimates (Conditions **AQ-2-22** through **-25**); and 2) non-compliance events and associated corrective maintenance (Condition **AQ-2-28**) in the Annual Compliance Reports (**AQ-SC8**).

The project owner shall submit source test plans to the District for approval and the CPM for review at least 15 days prior to testing. The project owner shall provide the results of the source tests to the District and a summary of the source test results, showing compliance with the emissions limits of Conditions **AQ-2-21** and **-22**, to the CPM within 60 days of testing. (Condition **AQ-2-29**)
The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-2** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-2-8** through **-35**)

AQ-3 The following conditions cover permit unit S-7616-18-0.

TRUCK UNLOADING AND TRANSFER SYSTEM FOR THE HANDLING OF PETROLEUM COKE (PETCOKE) AND/OR COAL, INCLUDING: ENCLOSED TRUCK

UNLOADING BUILDING SERVED BY BAGHOUSE DUST COLLECTOR AND DUST SUPPRESSION SPRAY SYSTEM, WITH TRUCK UNLOADING STATION(S), TRUCK UNLOADING BIN(S), BELT FEEDER(S), TRUCK UNLOADING CONVEYOR(S) ENCLOSED IN AN UNLOADING TUNNEL (SERVED BY A DUST COLLECTOR) THAT TRANSFERS MATERIAL TO TOWER #1 SERVING FEEDSTOCK STORAGE (S-7616-19)

8. Unloading hopper shall be equipped with water/additive misting system, which shall be employed as needed to control dust emissions during unloading. [District Rule 2201]

9. Operation shall include the following dust collectors serving the following operation(s): truck unloading station. [District Rule 2201]

10. Truck unloading station shall include water spray nozzles that shall be automatically activated at or prior to unloading as necessary to prevent visible emissions. [District Rule 2201]

11. All conveyors and crushers shall be fully enclosed and shall vent only to dust collectors. [District Rule 2201]

12. All feedstock processing and conveying equipment, feedstock storage systems, and feedstock transfer and loading systems shall be dust-tight (to prevent visible emissions in excess of 5 percent opacity) and shall vent only to dust collectors. [District Rules 2201, 4001, and 40 CFR 60.254]

13. Each dust collector shall be equipped with dust-tight (to prevent visible emissions in excess of 5 percent opacity) provisions to return collected material to process equipment. [District Rules 2201, 4001, and 40 CFR 60.254]

14. Each dust collector shall be equipped with operational differential pressure indicators, and during fabric collector operation read in the proper range specified by the manufacturer. [District Rule 2201]

15. The differential pressure across each compartment of the dust collectors shall be checked and the results recorded quarterly. If the differential pressure across each compartment of the dust collectors is not within the proper range specified by the manufacturer, corrective action is required prior to further operation of the equipment. Corrective action means that the cause of the improper pressure differential is corrected before operation of the equipment is resumed. [District Rule 2201]

16. Each dust collector shall automatically activate whenever process equipment served is activated. [District Rule 2201]

17. Enclosure dust suppression system water spray nozzles shall automatically operate when truck unloading is occurring. [District Rule 2201]

18. Material shall not be conveyed or crushed unless ventilation system and dust collectors are operating and functioning properly. [District Rule 2201]

19. Permittee shall maintain daily records of the hours of operation and weight of material processed by this operation, and records shall be made available for District inspection upon request. [District Rule 2201]

20. Airflow for the following dust collector(s) shall not exceed: truck unloading station: 80,000 cfm. [District Rule 2201]

21. Particulate matter emissions from the dust collectors shall not exceed 0.001 grains/dscf in concentration. [District Rules 2201, 4001, and 40 CFR 60.254]

22. PM10 emissions shall not exceed any of the following emissions for the following operation(s): truck unloading station: 16.5 lb/day. [District Rule 2201]

23. PM10 emissions shall not exceed any of the following emissions for the following operation(s): truck unloading station: 535 lb/yr. [District Rule 2201]

24. The maximum process rates of material on a weight basis shall not exceed any of the following: truck unloading station: 1,368 ton/day. [District Rule 2201]

25. The maximum process rates of material on a weight basis shall not exceed any of the following: truck unloading station: 177,840 ton/yr. [District Rule 2201]

26. Dust collector filters shall be completely inspected annually while not in operation for tears, scuffs, abrasives or holes which might interfere with PM collection efficiency and shall be replaced as needed. [District Rule 2201]

27. Visible emissions from the operation shall be checked and permittee shall record results quarterly. If visible emissions are observed, corrective action is required prior to further loading. Corrective action means that visible emissions are eliminated before next loading event. [District Rule 2201]

28. Records of dust control device maintenance, inspection, and repairs shall be maintained. The records shall include identification of equipment, date of inspection, corrective action taken, and identification of individual performing inspection. [District Rule 2201]

29. Testing for particulate matter concentration for each dust collector shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 12 calendar months of the date the previous performance test was required to be completed thereafter. If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(1), 40 CFR 60.8]

30. Testing for compliance with particulate matter concentration limit shall be conducted using EPA method 5. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin. A minimum of three valid test runs are needed to comprise a PM performance test. [District Rule 4001 and 40 CFR 60.255(1) and 60.257(5)(i)]

31. Testing for the opacity standards for the operations shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 90 operating days of the date the previous performance test was required to be completed thereafter. If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(2), 40 CFR 60.8]

32. Source testing to determine opacity as required by 40 CFR Part 60, Subpart Y shall be conducted using EPA method 9. [District Rule 4001 and 40 CFR 60.257(a)]

33. The permittee shall conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible. [District Rule 4001 and 40 CFR 60.257]

34. Permittee shall maintain a logbook (written or electronic) with the records specified in 40 CFR Subpart 60.258(a) on-site and make it available upon request. [District Rule 4001 and 40 CFR 60.258]

35. Permittee shall conduct testing for compliance with the particulate matter concentration limit and particulate matter emissions limit within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility. [District Rule 4001 and 40 CFR 60.258(c), 40 CFR 60.8]

Verification: The following verification requirements apply to applicable conditions for permit unit S-7616-18-0:

The project owner shall provide a summary of: 1) operations throughput and annual emissions estimates (Conditions **AQ-3-22** through **-25**); and 2) non-compliance events and associated corrective maintenance (Condition **AQ-3-28**) in the Annual Compliance Reports (**AQ-SC8**).

The project owner shall submit source test plans to the District for approval and the CPM for review at least 15 days prior to testing. The project owner shall provide the results of the source tests to the District and a summary of the source test results, showing compliance with the emissions limits of Conditions **AQ-3-21** and **-22**, to the CPM within 60 days of testing. (Condition **AQ-3-29**)

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-3** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-3-8** through **-35**)

AQ-4 The following conditions cover permit unit S-7616-19-0.

FEEDSTOCK STORAGE, BLENDING, AND RECLAIM SYSTEM INCLUDING: TRANSFER TOWER #1 (THAT TRANSFERS FEEDSTOCK FROM RAIL AND TRUCK UNLOADING AND TRANSFER SYSTEMS, S-7616-17 AND -18) SERVED BY A DUST COLLECTOR WITH COAL CRUSHER, REJECTS CONVEYOR(S); FEEDSTOCK STORAGE BUILDING (BARN) WITH A SEPARATE COAL AND PETCOKE STORAGE AREAS, STORAGE CONVEYOR(S), DISCHARGE CHUTE(S), AND RECLAIM CONVEYOR(S); AND TRANSFER TOWER #2 (THAT TRANSFERS MATERIAL TO THE FEEDSTOCK DRYING AND GRINDING/CRUSHING OPERATION, S-7616-20) SERVED BY TWO DUST COLLECTORS (ONE OPERATING AND ONE SPARE), TWO ENCLOSED TRANSFER CONVEYORS

8. Operation shall include the following dust collectors serving the following operation(s): feedstock transfer tower 1; feedstock transfer tower 2 [District Rule 2201]

9. All conveyors and crushers shall be fully enclosed and shall vent only to dust collectors. [District Rule 2201]

10. All feedstock processing and conveying equipment, feedstock storage systems, and feedstock transfer and loading systems shall be dust-tight (to prevent visible emissions in excess of 5 percent opacity) and shall vent only to dust collectors. [District Rules 2201, 4001, and 40 CFR 60.254]

11. Each dust collector shall be equipped with dust-tight (to prevent visible emissions in excess of 5 percent opacity) provisions to return collected material to process equipment. [District Rules 2201, 4001, and 40 CFR 60.254]

12. Each dust collector shall be equipped with operational differential pressure indicators, and during fabric collector operation read in the proper range specified by the manufacturer. [District Rule 2201]

13. The differential pressure across each compartment of the dust collectors shall be checked and the results recorded quarterly. If the differential pressure across each compartment of the dust collectors is not within the proper range specified by the manufacturer, corrective action is required prior to further operation of the equipment. Corrective action means that the cause of the improper pressure differential is corrected before operation of the equipment is resumed. [District Rule 2201]

14. Each dust collector shall automatically activate whenever process equipment served is activated. [District Rule 2201]

15. Enclosure dust suppression system water spray nozzles shall automatically operate when railcar unloading is occurring. [District Rule 2201]

16. Material shall not be conveyed or crushed unless ventilation system and dust collectors are operating and functioning properly. [District Rule 2201]

17. Permittee shall maintain daily records of the hours of operation and weight of material processed by this operation, and records shall be made available for District inspection upon request. [District Rule 2201]

18. Airflow for the following dust collector(s) shall not exceed: feedstock transfer tower 1: 1,500 cfm; feedstock transfer tower 2: 1,500 cfm. [District Rule 2201]

19. Particulate matter emissions from the dust collectors shall not exceed 0.001 grains/dscf in concentration. [District Rules 2201, 4001, and 40 CFR 60.254]

20. PM10 emissions shall not exceed any of the following emissions for the following operation(s): feedstock transfer tower 1: 0.3 lb/day; feedstock transfer tower 2: 0.3 lb/day. [District Rule 2201]

21. PM10 emissions shall not exceed any of the following emissions for the following operation(s): feedstock transfer tower 1: 16.0 lb/yr; feedstock transfer tower 2: 22.5 lb/yr. [District Rule 2201]

22. The maximum process rates of material on a weight basis shall not exceed any of the following: feedstock transfer tower 1: 6,107 ton/day; feedstock transfer tower 2: 7,475 ton/day. [District Rule 2201]

23. The maximum process rates of material on a weight basis shall not exceed any of the following: feedstock transfer tower 1: 793,910 ton/yr; feedstock transfer tower 2: 1,364,188 ton/yr. [District Rule 2201]

24. Dust collector filters shall be completely inspected annually while not in operation for tears, scuffs, abrasives or holes which might interfere with PM collection efficiency and shall be replaced as needed. [District Rule 2201]

25. Visible emissions from the operation shall be checked and record results quarterly. If visible emissions are observed, corrective action is required prior to further loading. Corrective action means that visible emissions are eliminated before next loading event. [District Rule 2201]

26. Records of dust control device maintenance, inspection, and repairs shall be maintained. The records shall include identification of equipment, date of inspection, corrective action taken, and identification of individual performing inspection. [District Rule 2201]

27. Testing for particulate matter concentration for each dust collector shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 12 calendar months

of the date the previous performance test was required to be completed thereafter. If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(1), 40 CFR 60.8]

28. Testing for compliance with particulate matter concentration limit shall be conducted using EPA method 5. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin. A minimum of three valid test runs are needed to comprise a PM performance test. [District Rule 4001 and 40 CFR 60.255(1) and 60.257(5)(i)]

29. Testing for the opacity standards for the operations shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 90 operating days of the date the previous performance test was required to be completed thereafter. If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(2), 40 CFR 60.8]

30. Source testing to determine opacity as required by 40 CFR Part 60, Subpart Y shall be conducted using EPA method 9. [District Rule 4001 and 40 CFR 60.257(a)]

31. The permittee shall conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible. [District Rule 4001 and 40 CFR 60.257]

32. Permittee shall maintain a logbook (written or electronic) with the records specified in 40 CFR Subpart 60.258(a) on-site and make it available upon request. [District Rule 4001 and 40 CFR 60.258]

33. Permittee shall conduct testing for compliance with the particulate matter concentration limit and particulate matter emissions limit within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility. [District Rule 4001 and 40 CFR 60.258(c), 40 CFR 60.8]

Verification: The following verification requirements apply to applicable conditions for permit unit S-7616-19-0:

The project owner shall provide a summary of: 1) operations throughput and annual emissions estimates (Conditions **AQ-4-20** through **-23**); and 2) non-compliance events and associated corrective maintenance (Condition **AQ-4-26**) in the Annual Compliance Reports (**AQ-SC8**).

The project owner shall submit source test plans to the District for approval and the CPM for review at least 15 days prior to testing. The project owner shall provide the results of the source tests to the District and a summary of the source test results, showing compliance with the emissions limits of Conditions **AQ-4-19** and **-20**, to the CPM within 60 days of testing. (Condition **AQ-4-27**)

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-4** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-4-8** through **-33**)

AQ-5 The following conditions cover permit unit S-7616-20-0.

FEEDSTOCK DRYING AND GRINDING/CRUSHING OPERATION INCLUDING: CRUSHER BUILDING SERVED BY BAGHOUSE DUST COLLECTOR, WITH SURGE BIN(S), BELT FEEDER(S), BYPASS SCREEN(S), TWO FEEDSTOCK CRUSHERS; TWO ENCLOSED PLANT FEED CONVEYORS SERVED BY BAGHOUSE DUST COLLECTOR; MILLING AND DRYING BUILDING WITH FEEDSTOCK DRYER [WITH DRYING GAS FROM TREATED EXHAUST GAS FROM HEAT RECOVERY STEAM GENERATOR LISTED ON S-7616-26] SERVED BY BAGHOUSE DUST COLLECTOR, WITH REVERSING CONVEYOR(S), DIVERTER GATE(S), AND TWO MILLING AND DRYING SILOS

8. Operation shall include the following dust collectors serving the following operation(s): feedstock bunkers; feedstock crusher. [District Rule 2201]

9. All conveyors and crushers shall be fully enclosed and shall vent only to dust collectors. [District Rule 2201]

10. All feedstock processing and conveying equipment, feedstock storage systems, and feedstock transfer and loading systems shall be dust-tight (to prevent visible emissions in excess of 5 percent opacity) and shall vent only to dust collectors. [District Rules 2201, 4001, and 40 CFR 60.254]

11. Each dust collector shall be equipped with dust-tight (to prevent visible emissions in excess of 5 percent opacity) provisions to return collected material to process equipment. [District Rules 2201, 4001, and 40 CFR 60.254]

12. Each dust collector shall be equipped with operational differential pressure indicators, and during fabric collector operation read in the proper range specified by the manufacturer. [District Rule 2201]

13. The differential pressure across each compartment of the dust collectors shall be checked and the results recorded quarterly. If the differential pressure across each compartment of the dust collectors is not within the proper range specified by the manufacturer, corrective action is required prior to further operation of the equipment. Corrective action means that the cause of the improper pressure differential is corrected before operation of the equipment is resumed. [District Rule 2201]

14. Each dust collector shall automatically activate whenever process equipment served is activated. [District Rule 2201]

15. Material shall not be conveyed or crushed unless ventilation system and dust collectors are operating and functioning properly. [District Rule 2201]

16. Permittee shall maintain daily records of the hours of operation and weight of material processed by this operation, and records shall be made available for District inspection upon request. [District Rule 2201]

17. Airflow for the following dust collector(s) shall not exceed: feedstock bunkers: 12,600 cfm; feedstock crusher: 12,600 cfm. [District Rule 2201]

18. Particulate matter emissions from the dust collectors shall not exceed 0.001 grains/dscf in concentration. [District Rules 2201, 4001, and 40 CFR 60.254]

19. PM10 emissions shall not exceed any of the following emissions for the following operation(s): feedstock bunkers: 2.6 lb/day; feedstock crusher: 2.6 lb/day. [District Rule 2201]

20. PM10 emissions shall not exceed any of the following emissions for the following operation(s): feedstock bunkers: 473 lb/yr; feedstock crusher: 473 lb/yr. [District Rule 2201]

21. The maximum process rates of material on a weight basis shall not exceed any of the following: feedstock bunkers: 7,475 ton/day; feedstock crusher: 7,475 ton/day. [District Rule 2201]

22. The maximum process rates of material on a weight basis shall not exceed any of the following: feedstock bunkers: 1,364,188 ton/yr; feedstock crusher: 1,364,188 ton/yr. [District Rule 2201]

23. Dust collector filters shall be completely inspected annually while not in operation for tears, scuffs, abrasives or holes which might interfere with PM collection efficiency and shall be replaced as needed. [District Rule 2201]

24. Visible emissions from the operation shall be checked and record results quarterly. If visible emissions are observed, corrective action is required prior to further loading. Corrective action means that visible emissions are eliminated before next loading event. [District Rule 2201]

25. Records of dust control device maintenance, inspection, and repairs shall be maintained. The records shall include identification of equipment, date of inspection, corrective action taken, and identification of individual performing inspection. [District Rule 2201]

26. Testing for particulate matter concentration for each dust collector shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 12 calendar months

of the date the previous performance test was required to be completed thereafter. If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(1), 40 CFR 60.8]

27. Testing for compliance with particulate matter concentration limit shall be conducted using EPA method 5. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin. A minimum of three valid test runs are needed to comprise a PM performance test. [District Rule 4001 and 40 CFR 60.255(1) and 60.257(5)(i)]

28. Testing for the opacity standards for the operations shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 90 operating days of the date the previous performance test was required to be completed thereafter. If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(2), 40 CFR 60.8]

29. Source testing to determine opacity as required by 40 CFR Part 60, Subpart Y shall be conducted using EPA method 9. [District Rule 4001 and 40 CFR 60.257(a)]

30. The permittee shall conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible. [District Rule 4001 and 40 CFR 60.257]

31. Permittee shall maintain a logbook (written or electronic) with the records specified in 40 CFR Subpart 60.258(a) on-site and make it available upon request. [District Rule 4001 and 40 CFR 60.258]

32. Permittee shall conduct testing for compliance with the particulate matter concentration limit and particulate matter emissions limit within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility. [District Rule 4001 and 40 CFR 60.258(c), 40 CFR 60.8]

<u>Verification:</u> The following verification requirements apply to applicable conditions for permit unit S-7616-20-0:

The project owner shall provide a summary of: 1) operations throughput and annual emissions estimates (Conditions **AQ-5-19** through **-22**); and 2) non-compliance events and associated corrective maintenance (Condition **AQ-5-25**) in the Annual Compliance Reports (**AQ-SC8)**.

The project owner shall submit source test plans to the District for approval and the CPM for review at least 15 days prior to testing. The project owner shall provide the results of the source tests to the District and a summary of the source test results, showing compliance with the emissions limits of Conditions **AQ-5-18** and **-19**, to the CPM within 60 days of testing. (Condition **AQ-5-27**)

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-5** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-5-8** through **-32**)

AQ-6 The following conditions cover permit unit S-7616-21-0.

GASIFICATION SYSTEM INCLUDING: ONE MHI OXYGEN-BLOWN GASIFIER; SYNGAS SCRUBBING SYSTEM; SOUR SHIFT/LOW TEMPERATURE GAS COOLING (LTGC) SYSTEM; SOUR WATER TREATMENT SYSTEM, MERCURY REMOVAL SYSTEM, AND RECTISOL ACID GAS REMOVAL (AGR) UNIT

8. Components attributed to this unit shall include those components serving the following process streams: methanol, syngas, shifted syngas, propylene, sour water, H2S-laden methanol, CO_2-laden methanol, acid gas, and ammonia-laden gas. [District Rule 2201]

9. Fugitive VOC emission rate from the unit shall not exceed 86.6 lb/day based on the component count and emission factors from EPA document Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017), Table 2-1, SOCMI Average Emissions Factors and the applicable control efficiency for those components subject to a leak detection and repair (LDAR) program. Components serving the following streams associated with this unit shall be subject to a leak detection and repair (LDAR) program: methanol, propylene, H2S-laden methanol, CO_2-laden methanol, acid gas, and ammonia laden gas. The following control efficiencies in Table 5-2 of the EPA document shall apply to those components under an LDAR program: gas valves: 92 percent; light liquid valves: 88 percent; light liquid pump seals: 75 percent; and connectors: 93 percent. [District Rules 2201 and 2410]

10. Fugitive CO emission rate from the unit shall not exceed 30.3 lb/day based on the component count, CO percentage in the fluid stream, emission factors from Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017), Table 2-1, SOCMI Average Emissions Factors and the applicable control efficiency for those components subject to a leak detection and repair (LDAR) program. [District Rule 2201]

11. Permittee shall maintain with the DOC an accurate fugitive component count and the resulting emissions calculated using above specified leak rates and control efficiencies. [District Rule 2201]

12. The VOC content of the gas in the following streams shall not exceed 10 percent by weight: syngas, shifted syngas, sour water, acid gas, ammonia-laden gas. [District Rule 2201]

13. Operator shall conduct quarterly gas sampling to qualify for exemption from fugitive component counts for those components handling fluids with VOC content equal to or less than 10 percent by weight. If gas samples are equal to or less than 10 percent VOC by weight for 8 consecutive quarterly samplings, sampling frequency shall only be required annually. [District Rule 2201]

14. VOC content of gas streams shall be determined by ASTM D1945, EPA Method 18 referenced as methane, or equivalent test method with prior District approval. [District Rule 2201]

15. All sampling connections, open-ended valves, and lines shall be equipped with two closed valves or be sealed with blind flanges, caps, or threaded plugs except during actual use. [District Rule 2201]

16. Permittee shall maintain records of the VOC content test results for a period of five years and make such records available for inspection upon request. [District Rule 1070]

17. For valves and connectors attributed to this unit, a leak shall be defined as a reading of methane in excess of 100 ppmv above background when measured per EPA Method 21. For pump and compressor seals attributed to this unit, a leak shall be defined as a reading of methane in excess of 500 ppmv above background when measure per EPA Method 21. [District Rule 2201]

18. The operator shall audio-visually inspect for leaks all accessible operating pumps, compressors and Pressure Relief Devices (PRDs) in service at least once every 24 hours, except when operators do not report to the facility for that given 24 hours. Any identified leak that cannot be immediately repaired shall be reinspected within 24 hours using a portable analyzer. If a leak is found, it shall be repaired as soon as practical but not later than the time frame specified in Rule 4455 Table 3. [District Rule 2201]

19. The operator shall inspect all components at least once every calendar quarter, except for inaccessible components, unsafe-to-monitor components and pipes. Inaccessible components, unsafe-to-monitor components and pipes shall be inspected in accordance with the requirements set forth in Rule 4455 Sections 5.2.5, 5.2.6, and 5.2.7. New, replaced, or repaired fittings, flanges and threaded connections shall be inspected immediately after being placed into service. Components shall be inspected using EPA Method 21. [District Rule 2201]

20. The operator may apply for a written approval from the APCO to change the inspection frequency from quarterly to annually for a component type, provided the operator meets all the criteria specified in Rule 4455 Sections 5.2.8.1 through 5.2.8.3. This approval shall apply to accessible component types, specifically

designated by the APCO, except pumps, compressors, and PRDs which shall continue to be inspected on a quarterly basis. [District Rule 2201]

21. An annual inspection frequency approved by the APCO shall revert to quarterly inspection frequency for a component type if either the operator inspection or District inspection demonstrates that a violation of the provisions of Rule 4455 Sections 5.1, 5.2 and 5.3 of the rule exists for that component type, or the APCO issued a Notice of Violation for violating any of the provisions of Rule 4455 during the annual inspection period for that component type. When the inspection frequency changes from annual to quarterly inspections, the operator shall notify the APCO in writing within five (5) calendar days after changing the inspection frequency, giving the reason(s) and date of change to quarterly inspection frequency. [District Rule 2201]

22. The operator shall initially inspect a process PRD that releases to the atmosphere as soon as practicable but not later than 24 hours after the time of the release. To insure that the process PRD is operating properly, and is leak-free, the operator shall re-inspect the process PRD not earlier than 24 hours after the initial inspection but not later than 15 calendar days after the date of the release using EPA Method 21. If the process PRD is found to be leaking at either inspection, the PRD leak shall be treated as if the leak was found during quarterly operator inspections. [District Rule 2201]

23. Except for process PRD, a component shall be inspected within 15 calendar days after repairing the leak or replacing the component using EPA Method 21. [District Rule 2201]

24. Upon detection of a leaking component, the operator shall affix to that component a weatherproof readily visible tag that contains the information specified in Rule 4455 Section 5.3.3. The tag shall remain affixed to the component until the leaking component has been repaired or replaced; has been re-inspected using EPA Method 21; and is found to be in compliance with leak, inspection, and maintenance requirements. [District Rule 2201]

25. An operator shall minimize all component leaks immediately to the extent possible, but not later than one (1) hour after detection of leaks in order to stop or reduce leakage to the atmosphere. [District Rule 2201]

26. If the leak has been minimized but the leak still exceeds the applicable leak standards of this DOC, an operator shall repair or replace the leaking component, vent the leaking component to a closed vent system, or remove the leaking component from operation as soon as practicable but not later than the time period specified in Rule 4455 Table 3. For each calendar quarter, the operator may be allowed to extend the repair period as specified in Rule 4455 Table 3, for a total number of leaking components, not to exceed 0.05 percent of the number of components inspected, by type, rounded upward to the nearest integer where required. [District Rule 2201]

27. If the leaking component is an essential component or a critical component which cannot be immediately shut down for repairs, the operator shall minimize the leak

within one hour after detection of the leak. If the leak has been minimized, but the leak still exceeds any of the applicable leak standards of the DOC, the essential component or critical component shall be repaired or replaced to eliminate the leak during the next process unit turnaround, but in no case later than one year from the date of the original leak detection, whichever comes earlier. [District Rule 2201]

28. For any component that has incurred five repair actions for major gas leaks or major liquid leaks, or any combination of major gas leaks and major liquid leaks within a continuous 12-month period, the operator shall comply with at least one of the requirements specified in Rule 4455 Sections 5.3.7.1, 5.3.7.2, 5.3.7.3, or 5.3.7.4 by the applicable deadlines specified in Sections 5.3.7.5 and 5.3.7.6. If the original leaking component is replaced with a new like-in-kind component before incurring five repair actions for major leaks within 12-consecutive months, the repair count shall start over for the new component. An entire compressor or pump need not be replaced provided the compressor part(s) or pump part(s) that have incurred five repair actions as described in Section 5.3.7 are brought into compliance with at least one of the requirements of Sections 5.3.7.1 through 5.3.7.6. [District Rule 2201]

29. All records required by this DOC shall be retained for a period of at least 5 years and shall be made available to the District upon request. [District Rules 1070 and 2201]

30. Sampling ports adequate for extraction of grab samples and measurement of gas flow rate shall be provided for both the influent and the effluent gas streams of the acid gas removal unit. [District Rules 1081 and 2410]

Verification: The following verification requirements apply to applicable conditions for permit unit S-7616-21-0:

The project owner shall provide a summary of non-compliance events and associated corrective maintenance (Condition **AQ-6-29**) in the Annual Compliance Reports (**AQ-SC8**).
The project owner shall provide a summary of the fugitive emissions LDAR program, per Conditions **AQ-6-8** through **-28**, in the Annual Compliance Reports (**AQ-SC8**).

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all AQ-6 Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-6-8** through **-30**)

AQ-7 The following conditions cover permit unit S-7616-22-0.

GASIFICATION SOLIDS MATERIAL HANDLING AND STORAGE SYSTEM INCLUDING: GASIFICATION SOLIDS UNLOADING BUNKER (STORAGE COVER WITH ROOFING AND PARTIAL SIDING) WITH DEWATERING TANK(S), STORAGE PILE(S), RECLAIM HOPPER AND GRIZZLY, BUCKET ELEVATOR FEED CONVEYOR SERVED BY DUST COLLECTOR, ENCLOSED TRANSFER CONVEYOR (TO GASIFICATION SOLIDS TRANSFER TOWER), GASIFICATION SOLIDS TRANSFER TOWER SERVED BY DUST COLLECTOR, WITH ENCLOSED LOAD-

OUT FEED CONVEYOR (TO GASIFICATION SOLIDS LOAD-OUT BUILDING); AND ENCLOSED GASIFICATION SOLIDS LOAD-OUT BUILDING SERVED BY BAGHOUSE DUST COLLECTOR, WITH GASIFICATION SOLIDS LOAD-OUT SYSTEM WITH ONE TRUCK AND ONE RAIL LOAD-OUT STATION

8. Operation shall include the following dust collectors serving the following operation(s): gasification solids bucket elevator; gasification solids transfer tower; gasification solids load-out system. [District Rule 2201]

9. All conveyors and crushers shall be fully enclosed and shall vent only to dust collectors. [District Rule 2201]

10. All material processing and conveying equipment, material storage systems, and material transfer and loading systems shall be dust-tight (to prevent visible emissions in excess of 5 percent opacity) and shall vent only to dust collectors. [District Rules 2201, 4001, and 40 CFR 60.254]

11. Each dust collector shall be equipped with dust-tight (to prevent visible emissions in excess of 5 percent opacity) provisions to return collected material to process equipment. [District Rules 2201, 4001, and 40 CFR 60.254]

12. Each dust collector shall be equipped with operational differential pressure indicators, and during fabric collector operation read in the proper range specified by the manufacturer. [District Rule 2201]

13. The differential pressure across each compartment of the dust collectors shall be checked and the results recorded quarterly. If the differential pressure across each compartment of the dust collectors is not within the proper range specified by the manufacturer, corrective action is required prior to further operation of the equipment. Corrective action means that the cause of the improper pressure differential is corrected before operation of the equipment is resumed. [District Rule 2201]

14. Each dust collector shall automatically activate whenever process equipment served is activated. [District Rule 2201]

15. Material shall not be conveyed or crushed unless ventilation system and dust collectors are operating and functioning properly. [District Rule 2201]

16. Permittee shall maintain daily records of the hours of operation and weight of material processed by this operation, and records shall be made available for District inspection upon request. [District Rule 2201]

17. Airflow for the following dust collector(s) shall not exceed: gasification solids bucket elevator: 3,000 cfm; gasification solids transfer tower: 3,000 cfm; gasification solids load-out system: 10,000 cfm. [District Rule 2201]

18. Particulate matter emissions from the dust collectors shall not exceed 0.001 grains/dscf in concentration. [District Rules 2201, 4001, and 40 CFR 60.254]

19. PM10 emissions shall not exceed any of the following emissions for the following operation(s): gasification solids bucket elevator: 0.6 lb/day; gasification solids transfer tower: 0.6 lb/day; gasification solids load-out system: 2.1 lb/day; gasification solids pad stacking: 0.1 lb/day; gasification solids pad reclaim: 0.2 lb/day. [District Rule 2201]

20. PM10 emissions shall not exceed any of the following emissions for the following operation(s): gasification solids bucket elevator: 225 lb/yr; gasification solids transfer tower: 32 lb/yr; gasification solids load-out system: 107 lb/yr; gasification solids pad stacking: 48 lb/yr; gasification solids pad reclaim: 85 lb/yr. [District Rule 2201]

21. The maximum process rates of material on a weight basis shall not exceed any of the following: gasification solids bucket elevator: 1,678 ton/day; gasification solids transfer tower: 1,678 ton/day; gasification solids load-out system: 1,678 ton/day. [District Rule 2201]

22. The maximum process rates of material on a weight basis shall not exceed any of the following: gasification solids bucket elevator: 612,470 ton/yr; gasification solids transfer tower: 87,256 ton/yr; gasification solids load-out system: 87,256 ton/yr. [District Rule 2201]

23. Moisture content of the solids stacking material shall be maintained at 12 percent or greater, by weight, and moisture content of solids reclaim material shall be maintained at 8 percent or greater, by weight. [District Rule 2201]

24. The percent moisture of the solids stacking material and the solids reclaim material shall be determined by weighing an approximately 2-lb sample of each material from in the material handling area, bringing the sample to dryness in a drying oven, then weighing the dried sample; the weight difference divided by the initial weigh of the sample; all multiply by 100 percent is the moisture content (percent moisture = ((initial weight - dry weight)/initial weight) x 100 percent). [District Rule 2201]

25. Moisture content of the solids stacking material and the solids reclaim material shall be measured on monthly basis and when requested by the District. [District Rule 2201]

26. Records of monthly moisture content of the solids stacking material and the solids reclaim material shall be maintained, retained on-site for a period of at least five (5) years and made available for District inspection upon request. [District Rule 2201]

27. Dust collector filters shall be completely inspected annually while not in operation for tears, scuffs, abrasives or holes which might interfere with PM collection efficiency and shall be replaced as needed. [District Rule 2201]

28. Visible emissions from the operation shall be checked and record results quarterly. If visible emissions are observed, corrective action is required prior to

further loading. Corrective action means that visible emissions are eliminated before next loading event. [District Rule 2201]

29. Records of dust control device maintenance, inspection, and repairs shall be maintained. The records shall include identification of equipment, date of inspection, corrective action taken, and identification of individual performing inspection. [District Rule 2201]

30. Testing for particulate matter concentration for each dust collector shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 12 calendar months of the date the previous performance test was required to be completed thereafter. If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(1), 40 CFR 60.8]

31. Testing for compliance with particulate matter concentration limit shall be conducted using EPA method 5. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin. A minimum of three valid test runs are needed to comprise a PM performance test. [District Rule 4001 and 40 CFR 60.255(1) and 60.257(5)(i)]

32. Testing for the opacity standards for the operations shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 90 operating days of the date the previous performance test was required to be completed thereafter. If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(2), 40 CFR 60.8]

33. Source testing to determine opacity as required by 40 CFR Part 60, Subpart Y shall be conducted using EPA method 9. [District Rule 4001 and 40 CFR 60.257(a)]

34. The permittee shall conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible. [District Rule 4001 and 40 CFR 60.257]

35. Permittee shall maintain a logbook (written or electronic) with the records specified in 40 CFR Subpart 60.258(a) on-site and make it available upon request. [District Rule 4001 and 40 CFR 60.258]

36. Permittee shall conduct testing for compliance with the particulate matter concentration limit and particulate matter emissions limit within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility. [District Rule 4001 and 40 CFR 60.258(c), 40 CFR 60.8]

<u>Verification:</u> The following verification requirements apply to applicable conditions for permit unit S-7616-20-0:

The project owner shall provide a summary of: 1) operations throughput and annual emissions estimates (Conditions **AQ-7-19** through **-22**); and 2) non-compliance events and associated corrective maintenance (Condition **AQ-7-29**) in the Annual Compliance Reports (**AQ-SC8**).

The project owner shall submit source test plans to the District for approval and the CPM for review at least 15 days prior to testing. The project owner shall provide the results of the source tests to the District and a summary of the source test results, showing compliance with the emissions limits of Conditions **AQ-7-18** and **-19**, to the CPM within 60 days of testing. (Condition **AQ-7-30**)

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-7** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-7-8** through **-36**)

AQ-8 The following conditions cover permit unit S-7616-23-0.

SULFUR RECOVERY AND TAIL GAS COMPRESSION SYSTEM CONSISTING OF SULFUR RECOVERY UNIT (SRU), A TAIL GAS UNIT (TGU) WITH A NATURAL GAS-FIRED TAIL GAS THERMAL OXIDIZER RATED UP TO 96 MMBTU/HR, AND MISCELLANEOUS TANKS, COMPRESSORS, PUMPS, CONDENSERS, HEAT EXCHANGERS, PIPING

11. The sulfur recovery unit shall consist of a single train designed to include two Claus converters, two reheaters, three sulfur condensers, waste gas boiler, reaction furnace, oxygen preheater (optional), main burner, acid gas preheater, acid gas wash drum, acid gas wash drum pumps, sour water stripper (SWS) acid gas knockout drum, SWS acid gas preheater, SWS acid gas drum pumps, combustion air blower(s), and piping. [District Rule 2201]

12. Tail gas unit (TGU) shall be designed to include a tail gas heater, tail gas trim heater (optional), hydrogenation reactor, reactor effluent cooler, contact condenser/desuperheater, desuperheater pumps, contact condenser cooler, tailgas compressor, and thermal oxidizer. [District Rule 2201]

13. The operation shall include continuously recording H2S monitor for incinerator inlet (on the TGU absorber overhead) and incinerator with continuously recording SO2 and O2 monitors. [District Rule 2201]

14. Exhaust stack shall be equipped with adequate provisions facilitating the collection of samples consistent with EPA test methods. [District Rule 1080]

15. Incinerator firebox temperature shall be maintained above 1,200 degrees F. [District Rule 2201]

16. Permittee shall maintain accurate records of the incinerator firebox temperature, and such records shall be maintained on site readily available for District inspection. [District Rule 2201]

17. Sulfur production shall not exceed 100 short tons/day. [District Rule 2201]

18. Permittee shall maintain accurate records of daily sulfur production, and such records shall be maintained on site readily available for District inspection. [District Rule 2201]

19. Shutdown is defined as the period beginning with the termination of acid gas feed and the initiation of fuel feed gas or nitrogen purge operation feed (for the purpose of heat stripping sulfur from the internal surfaces of the SRU). [District Rule 2201]

20. Warm standby is defined as the period between shutdown and startup when the SRU feed is solely natural gas. [District Rule 2201]

21. Startup is defined as the period beginning with the introduction (or increased utilization) of natural gas to the SRU to raise the temperature of the catalytic reactors to operating temperature (approximately 350 degrees F). Startup ends when the concentration of H2S in the TGU absorber offgas does not exceed 10 ppmv (moving 3-hour average). [District Rule 2201]

22. Except during shutdown, warm standby, startup, and breakdown (as defined in Rule 1100) conditions, concentration of H2S in the TGU absorber offgas when feeding the TGU incinerator shall not exceed 10 ppmv H2S (moving 3-hour average). [District Rule 2201]

23. The permittee shall, at all times including periods of startup, shutdown, and malfunction, maintain and operate the SRU and associated control equipment in a manner consistent with good air pollution control practice for minimizing emissions. [District Rule 2201]

24. In case of any exceedance of any H2S or SOx (as SO2) emission limit or any malfunction, permittee shall begin actions to minimize emissions exceedance or amount of sour gas flared, by removing high sulfur feed stocks and reducing unit rates, or by other means approved by the District. [District Rule 2201]

25. Emission rates from the tail gas thermal oxidizer shall not exceed the following: NOx: 0.24 lb/MMBtu; CO: 0.20 lb/MMBtu; VOC: 0.0055 lb/MMBtu; PM10: 0.0076 lb/MMBtu. [District Rule 2201]

26. SOx (as SO2) emissions from the tail gas thermal oxidizer shall not exceed 0.0204 lb/MMBtu for the disposal of SRU startup gas nor 2.00 lb/hr for the disposal of the process vent gas. [District Rule 2201]

27. The thermal oxidizer shall be fired solely on PUC-quality natural gas. [District Rules 2201 and 2410]

28. The thermal oxidizer firing rate shall not exceed 13.0 MMBtu/hr of natural gas from normal operation (for the disposal of process vent gas). The thermal oxidizer firing rate shall not exceed 80.0 MMBtu/hr of natural gas from SRU startup operation (for the disposal of SRU startup gas). [District Rule 2201]

29. The thermal oxidizer shall not exceed 8,314 hours per calendar year of normal operation (for the disposal of process vent gas) nor 48 hours per calendar year of SRU startup operation (for the disposal of SRU startup gas). [District Rules 2201 and 2410]

30. The annual heat input of the unit shall not exceed 111.9 billion Btu/yr. [District Rule 2201]

31. A non-resettable, totalizing, continuously recording, mass or volumetric fuel flow meter to measure the amount of natural gas combusted in the unit shall be installed, utilized and maintained. [District Rules 2201 and 2410]

32. Permittee shall maintain records of the annual heat input of the unit. [District Rules 1070 and 2201]

33. During SRU shutdown, SRU tail gas shall be directed to the TGU provided the O2 content of the SRU tail gas is less than or equal to 0.5 percent by weight as measured with portable O2 analyzer or equivalent CO value as measured by the CO/CO_2 analyzer. During such periods, SRU tail gas shall be directed to the TGU. During the final 12 hours of SRU shutdown, the SRU tail gas may bypass the TGU and be introduced directly to the incinerator. [District Rule 2201]

34. During SRU warm standby, SRU tail gas may bypass the TGU and be introduced directly to the incinerator. [District Rule 2201]

35. During SRU startup (after being completely down), SRU tail gas may bypass the TGU and be introduced directly to the incinerator provided the O2 content of the SRU tail is greater than zero percent by volume as measured with portable O2 analyzer or equivalent CO value as measured by the CO/CO_2 analyzer. The duration in which the TGU is bypassed shall not exceed 72 hours. [District Rule 2201]

36. During SRU startup (after being in warm standby), SRU tail gas shall be directed to the TGU. Within 24 hours of directing the SRU tail gas to the TGU, the TGU absorber offgas H2S content shall not exceed 10 ppmv (moving 3-hour average). [District Rule 2201]

37. All required source testing shall conform to the compliance testing procedures described in District Rule 1081. [District Rule 1081]

38. Within 90 days of startup and annually thereafter, operator shall conduct source testing of the thermal oxidizer to demonstrate compliance with SOx, NOx, CO and VOC emission limits. [District Rules 2201]

39. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

40. Source test results for NOx emissions shall be submitted to the District as NOx, NO, and NO2 when available. [District Rule 2410]

41. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

42. Copies of all fuel invoices, gas purchase contracts, supplier certifications, and test results to determine compliance with the conditions of this FDOC shall be maintained. The operator shall record daily amount and type(s) of fuel(s) combusted and all dates on which unit is fired on any noncertified fuel. [District Rule 2201]

43. Particulate matter emissions shall not exceed 0.1 grain/dscf calculated to 12 percent CO_2, nor 10 lb/hr. [District Rules 4201 and 4301, 5.1 and 5.2.3]

44. For the sulfur recovery unit, operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 10 ppm by volume (dry basis) of H2S at zero percent excess air (moving 3-hour average). [District Rule 2201]

45. For the sulfur recovery unit, a continuous emissions monitoring system shall be installed, calibrated, operated, and reported. Operator shall report all 3-hour periods during which the average concentration of H2S as measured by the H2S continuous monitoring system exceeds 10 ppm (dry basis, zero percent excess air). [District Rule 2201]

46. Operator shall determine compliance with the SO2 and H2S standard using EPA Method 3, EPA Method 6, and EPA Method 15. [District Rule 2201]

47. Components attributed to this unit shall include those components serving the following process streams: sulfur and tail gas unit (TGU) process gas. [District Rule 2201]

48. Fugitive VOC emission rate from the unit shall not exceed 0.0 lb/day based on the component count and emission factors from EPA document Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017), Table 2-1, SOCMI Average Emissions Factors. [District Rule 2201]

49. Fugitive CO emission rate from the unit shall not exceed 2.7 lb/day based on the component count, CO percentage in the fluid stream, emission factors from

Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017), Table 2-1, SOCMI Average Emissions Factors. [District Rule 2201]

50. Permittee shall maintain with the DOC an accurate fugitive component count and the resulting emissions calculated using above specified leak rates and control efficiencies. [District Rule 2201]

51. The VOC content of the gas in the following streams shall not exceed 10 percent by weight: sulfur, tail gas unit process gas. [District Rule 2201]

52. Operator shall conduct quarterly gas sampling to qualify for exemption from fugitive component counts for those components handling fluids with VOC content equal to or less than 10 percent by weight. If gas samples are equal to or less than 10 percent VOC by weight for 8 consecutive quarterly samplings, sampling frequency shall only be required annually. [District Rule 2201]

53. VOC content of gas streams shall be determined by ASTM D1945, EPA Method 18 referenced as methane, or equivalent test method with prior District approval. [District Rule 2201]

54. All sampling connections, open-ended valves, and lines shall be equipped with two closed valves or be sealed with blind flanges, caps, or threaded plugs except during actual use. [District Rule 2201]

55. Permittee shall maintain records of the VOC content test results for a period of five years and make such records available for inspection upon request. [District Rule 1070]

56. For valves and connectors attributed to this unit, a leak shall be defined as a reading of methane in excess of 100 ppmv above background when measured per EPA Method 21. For pump and compressor seals attributed to this unit, a leak shall be defined as a reading of methane in excess of 500 ppmv above background when measure per EPA Method 21. [District Rule 2201]

57. The operator shall audio-visually inspect for leaks all accessible operating pumps, compressors and Pressure Relief Devices (PRDs) in service at least once every 24 hours, except when operators do not report to the facility for that given 24 hours. Any identified leak that cannot be immediately repaired shall be reinspected within 24 hours using a portable analyzer. If a leak is found, it shall be repaired as soon as practical but not later than the time frame specified in Rule 4455 Table 3. [District Rule 2201]

58. The operator shall inspect all components at least once every calendar quarter, except for inaccessible components, unsafe-to-monitor components and pipes. Inaccessible components, unsafe-to-monitor components and pipes shall be inspected in accordance with the requirements set forth in Rule 4455 Sections 5.2.5, 5.2.6, and 5.2.7. New, replaced, or repaired fittings, flanges and threaded connections shall be inspected immediately after being placed into service. Components shall be inspected using EPA Method 21. [District Rule 2201]

59. The operator may apply for a written approval from the APCO to change the inspection frequency from quarterly to annually for a component type, provided the operator meets all the criteria specified in Rule 4455 Sections 5.2.8.1 through 5.2.8.3. This approval shall apply to accessible component types, specifically designated by the APCO, except pumps, compressors, and PRDs which shall continue to be inspected on a quarterly basis. [District Rule 2201]

60. An annual inspection frequency approved by the APCO shall revert to quarterly inspection frequency for a component type if either the operator inspection or District inspection demonstrates that a violation of the provisions of Rule 4455 Sections 5.1, 5.2 and 5.3 of the rule exists for that component type, or the APCO issued a Notice of Violation for violating any of the provisions of Rule 4455 during the annual inspection period for that component type. When the inspection frequency changes from annual to quarterly inspections, the operator shall notify the APCO in writing within five (5) calendar days after changing the inspection frequency, giving the reason(s) and date of change to quarterly inspection frequency. [District Rule 2201]

61. The operator shall initially inspect a process PRD that releases to the atmosphere as soon as practicable but not later than 24 hours after the time of the release. To insure that the process PRD is operating properly, and is leak-free, the operator shall re-inspect the process PRD not earlier than 24 hours after the initial inspection but not later than 15 calendar days after the date of the release using EPA Method 21. If the process PRD is found to be leaking at either inspection, the PRD leak shall be treated as if the leak was found during quarterly operator inspections. [District Rule 2201]

62. Except for process PRD, a component shall be inspected within 15 calendar days after repairing the leak or replacing the component using EPA Method 21. [District Rule 2201]

63. Upon detection of a leaking component, the operator shall affix to that component a weatherproof readily visible tag that contains the information specified in Rule 4455 Section 5.3.3. The tag shall remain affixed to the component until the leaking component has been repaired or replaced; has been re-inspected using EPA Method 21; and is found to be in compliance with leak, inspection, and maintenance requirements. [District Rule 2201]

64. An operator shall minimize all component leaks immediately to the extent possible, but not later than one (1) hour after detection of leaks in order to stop or reduce leakage to the atmosphere. [District Rule 2201]

65. If the leak has been minimized but the leak still exceeds the applicable leak standards of this PDOC, an operator shall repair or replace the leaking component, vent the leaking component to a closed vent system, or remove the leaking component from operation as soon as practicable but not later than the time period specified in Rule 4455 Table 3. For each calendar quarter, the operator may be allowed to extend the repair period as specified in Rule 4455 Table 3, for a total number of leaking components, not to exceed 0.05 percent of

the number of components inspected, by type, rounded upward to the nearest integer where required. [District Rule 2201]

66. If the leaking component is an essential component or a critical component and which cannot be immediately shut down for repairs, the operator shall minimize the leak within one hour after detection of the leak. If the leak has been minimized, but the leak still exceeds any of the applicable leak standards of the PDOC, the essential component or critical component shall be repaired or replaced to eliminate the leak during the next process unit turnaround, but in no case later than one year from the date of the original leak detection, whichever comes earlier. [District Rule 2201]

67. For any component that has incurred five repair actions for major gas leaks or major liquid leaks, or any combination of major gas leaks and major liquid leaks within a continuous 12-month period, the operator shall comply with at least one of the requirements specified in Rule 4455 Sections 5.3.7.1, 5.3.7.2, 5.3.7.3, or 5.3.7.4 by the applicable deadlines specified in Sections 5.3.7.5 and 5.3.7.6. If the original leaking component is replaced with a new like-in-kind component before incurring five repair actions for major leaks within 12-consecutive months, the repair count shall start over for the new component. An entire compressor or pump need not be replaced provided the compressor part(s) or pump part(s) that have incurred five repair actions as described in Section 5.3.7 are brought into compliance with at least one of the requirements of Sections 5.3.7.1 through 5.3.7.6. [District Rule 2201]

68. All records required by this DOC shall be retained for a period of at least 5 years and shall be made available to the District upon request. [District Rules 1070 and 2201]

69. The permittee shall obtain written District approval for the use of any equivalent equipment not specifically approved by this Determination of Compliance. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

70. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

71. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Determination of Compliance. [District Rule 2201]

72. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

73. The air quality modeled impacts of the proposed alternative equivalent equipment shall not result in any more adverse impacts than the equipment it replaces. [District Rule 2201]

Verification: The following verification requirements apply to applicable conditions for permit unit S-7616-23-0:

The project owner shall provide a summary of: 1) operations throughput and annual emissions estimates (Conditions **AQ-8-17**, **-22**, **-25**, **-26**, and **-28** through **-30**); and 2) non-compliance events and associated corrective maintenance (Condition **AQ-8-68**) in the Annual Compliance Reports (**AQ-SC8**).

The project owner shall submit source test plans in compliance with Condition **AQ-8-41** to the District for approval and the CPM for review at least 15 days prior to testing. The project owner shall provide the results of the source tests to the District and a summary of the source test results, showing compliance with the emissions limits of Conditions **AQ-8-22**, **-25**, and **-26**, to the CPM within 60 days of testing. (Conditions **AQ-8-38** and **-39**)

The project owner shall provide a summary of the fugitive emissions LDAR program, per Conditions **AQ-8-47** through **AQ-8-67**, in the Annual Compliance Reports (**AQ-SC8**).

The project owner shall submit the written request for the use of alternate equipment, if necessary, to both the District and CPM for approval in accordance with, and that meets, the standards of, Conditions **AQ-8-69** through **-73**.

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-8** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-8-11** through **-73**)

AQ-9 The following conditions cover permit unit S-7616-24-0.

CO_2 RECOVERY (CAPTURE, COMPRESSION, AND TRANSPORTATION) AND VENT SYSTEM FOR EMERGENCY RELEASES OF A STREAM OF PRIMARILY CO_2 FROM THE ACID GAS REMOVAL UNIT

8. Emission rates from the vent stream shall not exceed 492.4 lb-CO/hour, 11.3 lb-VOC/hour, 58.0 lb-COS/hour, nor 6.0 lb-H2S/hour. Compliance with these rates shall be demonstrated by measuring the vent stream flowrate and the concentration of these constituents in the vent stream. [District Rule 2201]

9. Venting shall only be allowed when compression and transportation system is unavailable or CO_2 delivery system is unavailable due to cold gasification block startup, CO_2 compressor unplanned outage, CO_2 pipeline unplanned outage, or CO_2 off-taker unable to accept, and emissions from such venting shall not exceed 124.07 tons-CO/yr, 2.34 tons-VOC/yr, nor 14.62 tons-COS/yr, per rolling 12-month period. Compliance with these rates shall be demonstrated by

measuring the vent stream flowrate and the concentration of these constituents in the vent stream. [District Rules 2201 and 2410]

10. Venting shall not exceed 504 hours per rolling 12-month period. [District Rules 2201and 2410]

11. Vent stream concentration shall not exceed 1,000 ppm-CO, 40 ppm-VOC, 55 ppm-COS, nor 10 ppm-H2S. [District Rules 2201 and 2410]

12. Emission rates from the vent stream shall not exceed 11,816.5 lb-CO/day nor 270.1 lb-VOC/day. [District Rules 2201 and 2410]

13. A non-resettable, totalizing mass or volumetric flow meter to measure the amount of gas vented shall be installed, utilized and maintained. [District Rules 2201 and 2410]

14. Each period of venting shall be reported to the District by the following working day, including the duration of the venting event and the vent gas composition observed. [District Rule 2201]

15. Hazardous Air Pollutant (HAP) emissions for the stationary source shall not exceed 25 ton/year for all HAPs nor 10 ton/year for any single HAP. [District Rule 4002]

16. Permittee shall conduct an initial speciated HAPs and total VOC source test for the CO_2 recovery and vent system by District witnessed in situ sampling of vented stream by a qualified independent source test firm. The permittee shall determine the total HAPs emissions rate, the single highest HAP emission rate, and the VOC mass emission during the source test. Initial compliance with the HAPs emissions limit (25 tpy all HAPs or 10 tpy any single HAP) shall be demonstrated by the combined VOC emissions rates determined during initial compliance source testing and the correlation between VOC emissions and HAP(s). Ongoing compliance shall be determined using mass flow and VOC sampling during venting occurrences as described in the condition below. [District Rule 4002]

17. The vent stream composition of CO, VOC, H2S, COS, and the HAPs identified in the initial speciated HAPs and total VOC source test, shall be measured during each venting occurrence exceeding 500,000 scf/day using EPA-approved test methods with a gas chromatograph or equivalent equipment as determined by the District in writing. [District Rule 2201]

18. Permittee shall monitor the CO_2 concentration in the CO_2 stream prior to the custody transfer. The permittee shall calculate the CO_2e emissions for each calendar month and shall maintain such records of onsite for District review. [District Rule 2410]

19. Permittee shall maintain records of the CO_2 concentration of the CO_2 stream prior to custody transfer and records of venting events, including the flowrate of the vent stream and reasons for venting event, and such records shall be

retained on site readily available for District inspection. [District Rules 2201 and 2410]

Verification: The following verification requirements apply to applicable conditions for permit unit S-7616-24-0:

The project owner shall provide a written summary of each CO_2 venting event, including the duration of the event, an estimate of the pollutant concentrations, an estimate of the pollutant mass emission rates, and the reason for venting, to the District by the following working day as required in this condition, and shall provide a summary of these reports and a summary of the venting emissions in the Annual Compliance Reports (**AQ-SC8**). (Conditions **AQ-9-14** and **-18**)

The project owner shall submit source test plans to the District for approval and the CPM for review at least 15 days prior to testing. The project owner shall provide the results of the source tests to the District and a summary of the source test results, showing compliance with the emissions limits of Conditions **AQ-9-8**, **-11**, and **-12**, to the CPM within 60 days of testing. (Condition **AQ-9-16**)

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-9** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-9-8** through **-19**)

AQ-10 The following conditions cover permit unit S-7616-25-0.

230 MMBTU/HR NATURAL GAS-FIRED AUXILIARY BOILER EQUIPPED WITH LOW-NOX BURNER WITH FLUE GAS RECIRCULATION AND SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM (OR EQUIVALENT)

11. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20 percent opacity. [District Rule 4101]

12. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

13. The unit shall be fired solely on PUC-quality natural gas. [District Rules 2201, 2410, 4320, 2410]

14. The boiler shall be equipped with an economizer and condensate recovery system. [District Rules 2201 and 2410]

15. Duration of startup and shutdown of heater shall not exceed 2 hours each per occurrence. The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. The operator shall maintain records of the duration of startup and shutdown. [District Rules 4305, 4306, and 4320]

16. Emissions from this unit, except during startup or shutdown, shall not exceed any of the following limits: NOx (as NO_2): 5.0 ppmvd @ 3 percent O_2 or 0.006 lb/MMBtu, SOx (as SO_2): 0.00285 lb/MMBtu, PM10: 0.005 lb/MMBtu, CO: 50.8 ppmvd @ 3 percent O_2 or 0.037 lb/MMBtu, or VOC: 0.0040 lb/MMBtu. [District Rules 2201, 4305, 4306 and 4320]

17. The maximum allowable heat input of the boiler shall not exceed 213 MMBtu/hr. [District Rule 2201]

18. The annual heat input of the unit shall not exceed 466.0 billion Btu per calendar year. [District Rules 2201 and 2410]

19. A non-resettable, totalizing, continuously recording, mass or volumetric fuel flow meter to measure the amount of natural gas combusted in the unit shall be installed, utilized and maintained. [District Rules 2201 and 2410]

20. Permittee shall maintain records of the annual heat input of the unit. [District Rules 1070 and 2201]

21. The operator shall tune the unit at least twice per calendar year, (from four to eight months apart) by a qualified technician, in accordance with the procedure described in Rule 4304 (Equipment Tuning Procedure for Boilers, Steam Generators, and Process Heaters). If the unit does not operate throughout a continuous six-month period within a calendar year, only one tune-up is required for that calendar year. No tune-up is required for any unit that is not operated during that calendar year; this unit may be test fired to verify availability of the unit for its intended use, but once the test firing is completed the unit shall be shutdown. [District Rule 2410]

22. The permittee shall monitor and record the stack concentration of NO_X, CO, and O_2 at least once every month (in which a source test is not performed) using a portable analyzer that meets District specifications. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305 and 4306]

23. If either the NO_X or CO concentrations corrected to 3 percent O_2, as measured by the portable analyzer, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100

in lieu of performing the notification and testing required by this condition. [District Rules 4305 and 4306]

24. All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305 and 4306]

25. The permittee shall maintain records of: (1) the date and time of NO_X, CO, and O_2 measurements, (2) the O_2 concentration in percent by volume and the measured NO_X and CO concentrations corrected to 3 percent O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305 and 4306]

26. This unit shall be tested for compliance with the NOx and CO emissions limits within 60 days of initial startup and at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305, 4306, and 4320]

27. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

28. Source test results for NOx emissions shall be submitted to the District as NOx, NO, and NO2 when available. [District Rule 2410]

29. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

30. The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306, and 4320]

31. All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the DOC. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305 and 4306]

32. The following test methods shall be used: NOx (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19, CO (ppmv) - EPA Method 10 or 10B or ARB Method 100, stack gas oxygen - EPA Method 3 or 3A or ARB Method 100, SOx (lb/MMBtu) - ARB Method 100 or EPA Method 6, 6C or fuel gas sulfur content analysis and EPA Method 19, fuel gas sulfur content - EPA Method 11 or 15, ASTM D3246 or double GC for H2S and mercaptans performed in a laboratory, fuel gas hhv - ASTM D1826 or D1945 in conjunction with ASTM D3588. [District Rules 4305, 4306 and 4320]

33. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every month (in which a source test is not performed) using a portable analyzer that meets District specifications. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305, 4306, and 4320]

34. If either the NOx or CO concentrations corrected to 3 percent O2, as measured by the portable analyzer, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 4305, 4306, and 4320]

35. All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the DOC. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306, and 4320]

36. The permittee shall maintain records of: (1) the date and time of NOx, CO, and O2 measurements, (2) the O2 concentration in percent by volume and the measured NOX and CO concentrations corrected to 3 percent O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305, 4306, and 4320]

37. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305, 4306, and 4320]

38. All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 2201, 4305, 4306, and 4320]

39. Permittee shall comply with all applicable NSPS requirements, including monitoring, notification and reporting requirements as described in 40 CFR 60 Subparts A and Db. [District Rule 4001]

40. Permittee shall submit to the EPA Regional Administrator for approval a plan that identifies the operating conditions to be monitored under 40 CFR 60.48b (g)(2) and the records to be maintained under 60.49b (j). This plan shall be submitted to the EPA Regional Administrator for approval within 360 days of the initial startup of the affected facility. [District Rule 4001]

41. The permittee shall obtain written District approval for the use of any equivalent equipment not specifically approved by this Determination of Compliance. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

42. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

43. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Determination of Compliance. [District Rule 2201]

44. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

45. The air quality modeled impacts of the proposed alternative equivalent equipment shall not result in any more adverse impacts than the equipment it replaces. [District Rule 2201]

__**Verification:**__ The following verification requirements apply to applicable conditions for permit unit S-7616-25-0:

The project owner shall provide a summary of: 1) operations throughput and annual emissions estimates (Conditions **AQ-10-15**, **-17**, **-18**, **-38**, and **-39**); 2) portable analyzer test results (Conditions **AQ-10-20** through **-23**); and 3) non-compliance events and associated corrective maintenance (Conditions **AQ-10-21** and **-38**) in the Annual Compliance Reports (**AQ-SC8**).

The project owner shall submit source test plans to the District for approval and the CPM for review at least 15 days prior to testing. The project owner shall provide the results of the source tests to the District and a summary of the source test results, showing compliance with the emissions limits of Condition **AQ-10-16**, to the CPM within 60 days of testing. (Condition **AQ-10-26**)

The project owner shall provide a copy of the NSPS operating plan, which shall be submitted to U.S.EPA within 360 days of initial facility startup, to the District and the CPM within a week of its submittal to U.S.EPA.

The project owner shall submit the written request for the use of alternate equipment, if necessary, to both the District and CPM for approval in accordance with, and that meets the standards of, Conditions **AQ-10-41** through **-45**.

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-10** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-10-11** through **-45**)

AQ-11 The following conditions cover permit unit S-7616-26-0.

431 MW NOMINAL (GROSS) COMBINED-CYCLE POWER GENERATING SYSTEM CONSISTING OF HYDROGEN-RICH SYNGAS FUEL AND/OR BACK UP NATURAL GAS-FIRED MHI 501GAC® G-CLASS, AIR-COOLED ADVANCED COMBUSTION TURBINE GENERATOR (CTG), WITH A HEAT RECOVERY STEAM GENERATOR (HRSG), AND A CONDENSING STEAM TURBINE-GENERATOR (STG) OPERATING IN COMBINED CYCLE MODE

11. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20 percent opacity. [District Rule 4101]

12. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

13. The owner/operator of the facility shall minimize the emissions from the gas turbine to the maximum extent possible during the commissioning period. [District Rule 2201]

14. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to insure safe and reliable steady state operation of the gas turbines and associated electrical delivery systems. [District Rule 2201]

15. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when a gas turbine is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial performance testing, completed final plant tuning, and is available for commercial operation. Two commissioning periods will occur: when firing on natural gas and when firing on hydrogen-rich fuel. [District Rule 2201]

16. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the combustors of this unit shall be tuned to minimize emissions. [District Rule 2201]

17. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the Selective Catalytic Reduction (SCR) system and the oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]

18. The permittee shall submit a plan to the District at least four weeks prior to the first firing of this unit, describing the procedures to be followed during the commissioning period. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not limited to, the tuning of the combustors, the installation and operation of the SCR system and the oxidation catalyst, the installation, calibration, and testing of the NOx and CO continuous emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system or oxidation catalyst. [District Rule 2201]

19. During the commissioning period when firing on natural gas, emission rates from the CTG/HRSG stack shall not exceed any of the following limits: NOx (as NO2) - 391.20 lb/hr; SOx - 4.80 lb/hr; PM10 - 15.00 lb/hr; CO - 2,270.00 lb/hr; or VOC (as methane) - 65.00 lb/hr. During the commissioning period when firing on hydrogen-rich fuel, emission rates from the CTG shall not exceed any of the following limits: NOx (as NO2) - 99.04 lb/hr; SOx - 5.00 lb/hr; PM10 - 15.00 lb/hr; CO - 1622.60 lb/hr; or VOC (as methane) - 35.12 lb/hr. [District Rule 2201]

20. During the commissioning period, the permittee shall demonstrate NOx and CO compliance with the condition above through the use of properly operated and maintained continuous emissions monitors and recorders as specified in this document. The monitored parameters for this unit shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation). [District Rule 2201]

21. The continuous emissions monitors specified in these conditions shall be installed, calibrated and operational prior to the first firing of the unit. After first firing, the detection range of the CEMS shall be adjusted as necessary to accurately measure the resulting range of NOx and CO emissions concentrations. [District Rule 2201]

22. During the commissioning period on natural gas, this unit shall not fire more than 456 total hours without abatement of emissions by the SCR system and/or the oxidation catalyst. During the commissioning period on hydrogen-rich fuel, this unit shall not fire more than 50 total hours without abatement of emissions by the SCR system and/or the oxidation catalyst and shall not fire more than 200 total hours without the partial operation of the SCR system and/or the oxidation catalyst. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and the oxidation catalyst in place. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the firing hours without abatement shall expire. Records of the commissioning hours of operation for the unit shall be maintained. [District Rule 2201]

23. The total mass emissions of NOx, SOx, PM10, CO, and VOC that are emitted during the commissioning period shall accrue towards the consecutive twelve month emission limits specified in this document. NOx and CO total mass emissions will be determined from CEMs data and SOx, PM10, and VOC total mass emissions will be calculated. [District Rule 2201]

24. A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve the gas turbine engine. Exhaust ducting may be equipped (if required) with a fresh air inlet blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst. The permittee shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

25. Permittee shall submit continuous emission monitor design, installation, and operational details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

26. The permittee shall submit to the District information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this DOC when no continuous emission monitoring data for NOx is available or when the continuous emission monitoring system is not operating properly. [District Rule 4703]

27. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

28. Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5 percent or greater, except for a period or periods not exceeding three minutes in any one hour. [District Rules 2201 and 4101]

29. This unit shall be fired on hydrogen-rich fuel or on PUC-regulated natural gas backup fuel. Firing on backup PUC-quality natural gas shall only occur during CTG startups (with firing on natural gas not to exceed 5 total hours per calendar

year), CTG shutdowns (with firing on natural gas not to exceed 10 hours per calendar year), or during periods of unplanned equipment outages (with firing on natural gas not to exceed 336 hours per calendar year). [District Rule 2201 and 2410]

30. This unit shall be fired on hydrogen-rich fuel with a sulfur content no greater than 10 ppmv, or on PUC-regulated natural gas with a sulfur content of no greater than 0.75 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rules 2201 and 2410, and 40 CFR 60.4330(a)(2)]

31. During normal operation (excluding startup and shutdown), emission rate from the CTG/HRSG stack when firing on hydrogen-rich fuel shall not exceed any of the following: NOx (as NO2) - 25.0 lb/hr and 2.5 ppmvd-NOx @ 15 percent O2 (1-hour average); VOC (as methane) - 3.5 lb/hr and 1.0 ppmvd-VOC @ 15 percent O2; CO - 18.3 lb/hr and 3.0 ppmvd-CO @ 15 percent O2; PM10 - 12.9 lb/hr; or SOx (as SO2) - 4.1 lb/hr. The NOx (as NO2) emission limit indicated above is a one-hour rolling average. All other pollutant emission limits are three-hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

32. During normal operation (excluding startup and shutdown), emission rate from the feedstock dryer stack when firing on hydrogen-rich fuel shall not exceed any of the following: NOx (as NO2) - 4.4 lb/hr and 2.5 ppmvd-NOx @ 15 percent O2 (1-hour average); VOC (as methane) - 0.6 lb/hr and 1.0 ppmvd-VOC @ 15 percent O2; CO - 3.2 lb/hr and 3.0 ppmvd-CO @ 15 percent O2; PM10 - 1.4 lb/hr; or SOx (as SO2) - 0.9 lb/hr. The NOx (as NO2) emission limit indicated above is a one-hour rolling average. All other pollutant emission limits are three-hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

33. During normal operation (excluding startup and shutdown), emission rate from the CTG/HRSG stack when firing on natural gas shall not exceed any of the following: NOx (as NO2) - 34.1 lb/hr and 4.0 ppmvd-NOx @ 15 percent O2; VOC (as methane) - 5.9 lb/hr and 2.0 ppmvd-VOC @ 15 percent O2; CO - 26.0 lb/hr and 5.0 ppmvd-CO @ 15 percent O2; PM10 - 15.0 lb/hr; or SOx (as SO2) - 4.7 lb/hr. All pollutant emission limits are three-hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

34. Ammonia (NH3) emissions shall not exceed either of the following limits: 18.50 lb/hr or 5.0 ppmvd @ 15 percent O2 (based on a 24 hour rolling average). [District Rule 2201]

35. During startup, emission rates from the CTG/HRSG stack shall not exceed any of the following: NOx (as NO2) - 107.20 lb/hr, SOx - 2.40 lb/hr, PM10 - 15.00 lb/hr, CO - 2,270.00 lb/hr, or VOC - 65.00 lb/hr, based on one-hour averages. During startup, emission rates from the CTG/HRSG stack shall not exceed any of the following: NOx (as NO2) - 381.2 lb/day, SOx - 10.7 lb/day, PM10 - 59.7 lb/day, CO - 3,385.0 lb/day, or VOC - 67.7 lb/day. [District Rule 2201]

36. During startup, emission rates from the feedstock dryer stack shall not exceed any of the following: NOx (as NO2) - 15.10 lb/hr, SOx - 0.30 lb/hr, PM10 - 0.90 lb/hr, CO - 147.40 lb/hr, or VOC - 1.90 lb/hr, based on one-hour averages. During startup, emission rates from the feedstock dryer stack shall not exceed any of the following: NOx (as NO2) - 49.0 lb/day, SOx - 1.2 lb/day, PM10 - 3.6 lb/day, CO - 317.8 lb/day, or VOC - 5.2 lb/day. [District Rule 2201]

37. During shutdown, emission rates from the CTG/HRSG stack shall not exceed any of the following: NOx (as NO2) - 122.0 lb/hr, SOx - 2.7 lb/hr, PM10 - 15.0 lb/hr, CO - 2,270.0 lb/hr, or VOC - 64.8 lb/hr, based on one-hour averages. During shutdown, emission rates from the CTG/HRSG stack shall not exceed any of the following: NOx (as NO2) - 766.6 lb/day, SOx - 21.9 lb/day, PM10 - 127.0 lb/day, CO - 8,437.0 lb/day, or VOC - 193.9 lb/day. [District Rule 2201]

38. During shutdown, emission rates from the feedstock dryer stack shall not exceed any of the following: NOx (as NO2) - 9.4 lb/hr, SOx - 0.3 lb/hr, PM10 - 0.9 lb/hr, CO - 11.5 lb/hr, or VOC - 0.7 lb/hr, based on one-hour averages. During shutdown, emission rates from the feedstock dryer stack shall not exceed any of the following: NOx (as NO2) - 37.6 lb/day, SOx - 1.2 lb/day, PM10 - 3.6 lb/day, CO - 46.0 lb/day, or VOC - 2.8 lb/day. [District Rule 2201]

39. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

40. For CTG/HRSG, the duration of each startup event shall not exceed 4.5 hours, and the duration of each shutdown event shall not exceed 9.0 hours. For feedstock dryer, the duration of each startup event shall not exceed 4.0 hours, and the duration of each shutdown event shall not exceed 4.0 hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

41. CTG/HRSG and feedstock dryer shall each be limited to two startups and two shutdowns per calendar year. [District Rule 2201]

42. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

43. Daily emissions from the CTG/HRSG stack when firing on hydrogen-rich fuel on days without a startup or shutdown shall not exceed any of the following: NOx (as NO2) - 600.0 lb/day; CO - 439.2 lb/day; VOC - 84.0 lb/day; PM10 - 309.6 lb/day; SOx (as SO2) - 98.4 lb/day, or NH3 - 444.0 lb/day. [District Rule 2201]

44. Daily emissions from the CTG/HRSG stack when firing on natural gas on days without a startup or shutdown shall not exceed any of the following: NOx (as NO2) - 818.4 lb/day; CO - 624.0 lb/day; VOC - 141.6 lb/day; PM10 - 360.0 lb/day; SOx (as SO2) - 112.8 lb/day, or NH3 - 379.2 lb/day. [District Rule 2201]

45. Daily emissions from the feedstock dryer stack when firing on hydrogen-rich fuel on days without a startup or shutdown shall not exceed any of the following: NOx (as NO2) - 105.6 lb/day; CO - 76.8 lb/day; VOC - 14.4 lb/day; PM10 - 33.6 lb/day; SOx (as SO2) - 21.6 lb/day, or NH3 - 76.8 lb/day. [District Rule 2201]

46. Annual emissions from the CTG/HRSG stack, calculated on a twelve-consecutive month rolling basis, shall not exceed any of the following: NOx (as NO2) - 212,953 lb/year; SOx (as SO2) - 34,445 lb/year; PM10 - 107,813 lb/year; CO - 177,980 lb/year; or VOC - 30,506 lb/year. [District Rule 2201]

47. Annual emissions from the feedstock dryer stack, calculated on a twelve-consecutive month rolling basis, shall not exceed any of the following: NOx (as NO2) - 33,773 lb/year; SOx (as SO2) - 5,605 lb/year; PM10 - 11,257 lb/year; CO - 25,528 lb/year; or VOC - 4,816 lb/year. [District Rule 2201]

48. Each one-hour period shall commence on the hour. Each one-hour period in a three-hour rolling average will commence on the hour. The three-hour average will be compiled from the three most recent one-hour periods. Each one-hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

49. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

50. Compliance with the ammonia emission limits shall be demonstrated utilizing one of the following procedures: 1.) calculate the daily ammonia emissions using the following equation: (ppmvd @ 15 percent O2) = ((a - (b x c/1,000,000)) x (1,000,000 / b)) x d, where a = average ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NOx concentration ppmvd @ 15 percent O2 across the catalyst, and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip; 2.) Utilize another District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15 percent O2. If this option is chosen, the permittee shall submit a detailed calculation protocol for District approval at least 60 days prior to commencement of operation; 3.) Alternatively, the permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. If this option is chosen, the permittee shall submit a monitoring plan for District

approval at least 60 days prior to commencement of operation. [District Rule 2201]

51. Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. If CEM data is not certifiable to determine compliance with NOx and CO startup emission limits, then source testing to measure startup NOx and CO mass emission rates shall be conducted at least once every 12 months. [District Rule 1081]

52. Hazardous Air Pollutant (HAP) emissions for the stationary source shall not exceed 25 ton/year for all HAPS nor 10 ton/year for any single HAP. [District Rule 4002]

53. Permittee shall conduct an initial speciated HAPs and total VOC source test for the combustion turbine generator, by District witnessed in situ sampling of exhaust gases by a qualified independent source test firm. The permittee shall correlate the total HAPs emissions rate and the single highest HAP emission rate to the VOC mass emission determined during the speciated HAPs source test. Initial and annual compliance with the HAPs emissions limit (25 tpy all HAPs or 10 tpy any single HAP) shall be demonstrated by the combined VOC emissions rates for the combustion gas turbine determined during initial and annual compliance source testing and the correlation between VOC emissions and HAP(s). [District Rule 4002]

54. Source testing to measure the NOx, CO, VOC, and NH3 emission rates (lb/hr and ppmvd @ 15 percent O2) and PM10 emission rate (lb/hr) shall be conducted within 60 days after the conclusion of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703 and 40 CFR 60.4400(a)]

55. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

56. Source test results for NOx emissions shall be submitted to the District as NOx, NO, and NO2 when available. [District Rule 2410]

57. The sulfur content of the natural gas fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) shall be demonstrated within 60 days after the end of the commissioning period and monitored weekly thereafter. If the sulfur content is demonstrated to be less than 0.75 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

58. The following test methods shall be used: NOx - EPA Method 7E or 20, PM10 - EPA Method 5/202 (front half and back half), CO - EPA Method 10 or 10B, O2 - EPA Method 3, 3A, or 20, VOC - EPA Method 18 or 25, and ammonia - EPA Method 206. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this DOC. The request to utilize EPA approved alternative source testing methods must be submitted in writing and written approval received from the District prior to the submission of the source test plan. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

59. HHV and LHV of the fuel shall be determined using ASTM D3588, ASTM 1826, or ASTM 1945. [40 CFR 60.332(a),(b) and District Rule 4703, 6.4.5]

60. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

61. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Source Emission Monitoring and Testing. [District Rule 1080]

62. Compliance demonstration (source testing) shall be District witnessed or authorized and samples shall be collected by a certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

63. The turbine shall be equipped with a continuous monitoring system to measure and record fuel consumption. [District Rules 2201 and 4703 and 40 CFR 60.4335(b)(1)]

64. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NOx, CO and O2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns provided the CEMS pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 2201, and 4703 and 40 CFR 60.4335(b)(1)]

65. CEMS shall continuously measure and record the parameters required in the condition above for both the CTG/HRSG exhaust and the feedstock dryer exhaust. [District Rules 1080, 2201, and 4703 and 40 CFR 60.4335(b)(1)]

66. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

67. The NOx, CO and O2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

68. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

69. The owner/operator shall perform a relative accuracy test audit (RATA) for the NOx, CO, and O2 CEMs as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

70. Results of the CEM system shall be averaged over a one hour period for NOx emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

71. Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NOx concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NOx or O2 (or both). [40 CFR 60.4380(b)(1)]

72. Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

73. The permittee shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

74. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

75. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

76. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

77. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

78. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

79. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

80. When operating the turbine on hydrogen-rich fuel, no less than 90 percent (by weight) of the pre-combustion carbon in the gasified fuel stream shall be removed. [District Rule 2410]

81. Sampling ports adequate for extraction of grab samples and measurement of gas flow rate shall be provided for both the influent and the effluent gas streams of the acid gas removal unit. [District Rules 1081 and 2410]

82. Operator shall monitor the syngas flow rate and the CO, CO_2, and CH4 concentration in the gas upstream and downstream of the acid gas removal (AGR) unit using laboratory sample analysis at least once every month. [District Rules 1081 and 2410]

83. Compliance with the 90 percent (by weight) reduction in the pre-combustion carbon content in the gasified fuel stream shall be demonstrated by the results of the laboratory sample analysis and flow rates once every month. [District Rules 1081 and 2410]

84. The permittee shall maintain records of the CO, CO_2, and CH4 concentration upstream and downstream of the AGR unit, the syngas flow rate, and the carbon capture percentage captured. [District Rule 2410]

85. Except as noted below, removed pre-combustion CO_2 stream shall be transported and sequestered to Occidental of Elk Hills (OEHI) in compliance with the latest OEHI CO_2 project Monitoring, Reporting and Verification (MRV) Plan that has been approved by California Department of Oil, Gas and Geothermal Resource. Venting of the CO_2 stream shall only be allowed when compression and transportation system is unavailable or CO_2 delivery system is unavailable due to cold gasification block startup, CO_2 compressor unplanned outage, CO_2 pipeline unplanned outage, or CO_2 off-taker unable to accept. Such venting shall not exceed 504 hours per rolling 12-month period. [District Rule 2410]

86. The permittee shall demonstrate compliance with the emission performance standard of 400 lb/MWh using the calculation methodology established by SB 1368 (Greenhouse Gases Emission Performance Standard) for each calendar month. The permittee shall calculate the facility's emission performance value and maintain records of this value. [District Rule 2410]

87. CO_2e emissions from entire stationary source (S-7616) shall not exceed 595,917 tons per calendar year. The permittee shall calculate the CO_2e emissions for each calendar month and shall maintain such records onsite for District review. [District Rule 2410]

88. The circuit breakers at the facility shall be enclosed-pressure SF6 circuit breakers with a leak detection system that consists of a density alarm that provides a warning prior to a total of 10 percent of the SF6 (by weight) of the circuit breakers has escaped. Within 30 days of the alarm, circuit breakers shall be replaced or the leak shall be repaired to prevent further release of the gas. [District Rule 2410]

89. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]

90. The permittee shall maintain the following records: quarterly hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

91. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201, and 4703]

Verification: The following verification requirements apply to applicable conditions for permit unit S-7616-26-0:

The project owner shall submit, at least four weeks prior to first fire of the gas turbine, to the APCO for approval and the CPM for review, the commissioning plan for the gas turbine (Condition **AQ-11-18**). The project owner shall submit to the CPM in the Monthly Compliance Reports information demonstrating compliance with the initial commissioning continuous emissions monitoring requirements (Conditions **AQ-11-20** and **-21**). The project owner shall provide a summary of the gas turbine operations during initial commissioning to the CPM in the final Monthly Compliance Report demonstrating compliance with the requirements of Conditions **AQ-11-13**, **-16**, **-17**, **-19**, and **-22**.

The project owner shall provide the SCR system and oxidation catalyst system design plans and a Continuous Emission Monitoring System (CEM) design plan to the APCO for approval and the CPM for review at least 30 days prior to commencement of construction (Conditions **AQ-11-24** and **-25**). The CEMS shall be designed to comply with Conditions **AQ-11-63** through **-77**.

The project owner shall provide the APCO for approval and the CPM for review NOx control system operations versus measured NOx emissions correlations after each NOx source test performed for this unit within the source test report or separately within 30 days of submittal of the source test report. (Condition **AQ-11-26**)

The project owner shall provide a summary of: 1) operations throughput and emissions estimates based on CEMS and source test data (Conditions **AQ-11-29**, **-30** through **-47**, and **-52**); and 2) non-compliance events and associated corrective maintenance (Condition **AQ-11-89**) in the Annual Compliance Reports (**AQ-SC8**).

The project owner shall submit source test plans to the District for approval and the CPM for review at least 15 days prior to testing. The project owner shall provide the results of the source tests to the District and a summary of the source test results, showing compliance with the emissions limits of Conditions **AQ-11-31** through **-38**, as appropriate to the test, to the CPM within 60 days of testing (Conditions **AQ-11-55** and **-62**). The source test timing and methods shall follow the specification of Conditions **AQ-11-51**, **-53**, **-54**, **-56**, **-58**, and **-61**.

The project owner shall submit the CEMS audit reports to the District in the District's quarterly operation reports and to the CPM in the Quarterly Operation Reports (**AQ-SC8**).

The project owner shall submit a summary of the results of the fuel HHV/LHV and sulfur content tests, performed as required in Conditions **AQ-11-57**, **-59**, and **-60**, in the Annual Compliance Reports (**AQ-SC8**).

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-11** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-11-11** through **-91**)

The project owner shall submit CO_2 and CO_2E emissions estimates to the CPM as required in staff Conditions of Certification **GHG-1** through **GHG-5** that demonstrate compliance with Conditions **AQ-11-80** through **-88**.

AQ-12 The following conditions cover permit unit S-7616-27-0.

MULTI-CELL MECHANICAL-DRAFT COOLING TOWER WITH HIGH-EFFICIENCY DRIFT ELIMINATORS, SERVING GASIFICATION BLOCK AND PROCESS UNITS

7. Permittee shall submit cooling tower design details including the cooling tower type, drift eliminator design details, and materials of construction to the District at least 90 days before the tower is operated. [District Rule 7012]

9. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

10. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20 percent opacity. [District Rule 4101]

11. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

12. No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012]

13. Drift eliminator drift rate shall not exceed 0.0005 percent. [District Rule 2201]

14. Total dissolved solids (TDS) in circulating water shall not exceed 9,000 mg/liter. [District Rule 2201]

15. Compliance with TDS limit shall be determined by cooling water sample analysis by independent laboratory within 60 days of initial operation and quarterly thereafter. [District Rule 1081]

16. Cooling tower circulation water flow rate shall not exceed 162,582 gallons per minute nor 81.1 billion gallons per calendar year. [District Rule 2201]

17. A non-resettable, totalizing mass or volumetric flow meter to measure circulation water flow rate shall be installed, utilized and maintained. [District Rule 2201]

18. PM10 emission rate from the cooling tower shall not exceed 87.9 lb/day. [District Rule 2201]

19. Compliance with the PM10 daily emission limit shall be demonstrated as follows: PM10 lb/day = circulating water recirculation rate x total dissolved solids concentration in the circulating water x manufacturer's design drift rate. [District Rule 2201]

20. Records of the cooling tower circulating water flow rate and cooling tower water TDS shall be kept at the facility and made readily available for District inspection upon request for 5 years. [District Rule 1070]

Verification: The following verification requirements apply to applicable conditions for permit unit S-7616-27-0:

The project owner shall provide the manufacturer data for cooling tower, including the guarantee data for the drift eliminator, showing compliance with Condition **AQ-12-13** shall be provided to the CPM and the District at least 90 days prior to cooling tower operation. (Condition **AQ-12-7**)

The project owner shall provide a summary of the water sample analyses showing compliance with the TDS limits in Condition **AQ-12-14**, and daily and annual emissions summaries showing compliance with Condition **AQ-12-18** shall be provided as part of the Annual Compliance Reports (**AQ-SC8**).

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-12** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-12-7** through **-20**)

AQ-13 The following conditions cover permit unit S-7616-28-0.

MULTI-CELL MECHANICAL-DRAFT COOLING TOWER WITH HIGH-EFFICIENCY DRIFT ELIMINATORS, SERVING AIR SEPARATION UNIT

7. Permittee shall submit cooling tower design details including the cooling tower type, drift eliminator design details, and materials of construction to the District at least 90 days before the tower is operated. [District Rule 7012]

9. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

10. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20 percent opacity. [District Rule 4101]

11. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

12. No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012]

13. Drift eliminator drift rate shall not exceed 0.0005 percent. [District Rule 2201]

14. Total dissolved solids (TDS) in circulating water shall not exceed 2,000 mg/liter. [District Rule 2201]

15. Compliance with TDS limit shall be determined by cooling water sample analysis by independent laboratory within 60 days of initial operation and quarterly thereafter. [District Rule 1081]

16. Cooling tower circulation water flow rate shall not exceed 44,876 gallons per minute nor 22.40 billion gallons per calendar year. [District Rule 2201]

17. A non-resettable, totalizing mass or volumetric flow meter to measure circulation water flow rate shall be installed, utilized and maintained. [District Rule 2201]

18. PM10 emission rate from the cooling tower shall not exceed 8.1 lb/day. [District Rule 2201]

19. Compliance with the PM10 daily emission limit shall be demonstrated as follows: PM10 lb/day = circulating water recirculation rate x total dissolved solids concentration in the circulating water x manufacturer's design drift rate. [District Rule 2201]

20. Records of the cooling tower circulating water flow rate and cooling tower water TDS shall be kept at the facility and made readily available for District inspection upon request for 5 years. [District Rule 1070]

<u>Verification:</u> The following verification requirements apply to applicable conditions for permit unit S-7616-28-0:

The project owner shall provide the manufacturer data for cooling tower, including the guarantee data for the drift eliminator, showing compliance with Condition **AQ-13-13** to the CPM and the District at least 90 days prior to cooling tower operation. (District Condition 7)

The project owner shall provide a summary of the water sample analyses showing compliance with the TDS limits in Condition **AQ-13-14**, and daily and annual emissions summaries showing compliance with Condition **AQ-13-18** shall be provided as part of the Annual Compliance Reports (**AQ-SC8**).

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-13** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-13-7** through **-20**)

AQ-14 The following conditions cover permit unit S-7616-29-0.

MULTI-CELL MECHANICAL-DRAFT COOLING TOWER WITH HIGH-EFFICIENCY DRIFT ELIMINATORS, SERVING POWER BLOCK

7. Permittee shall submit cooling tower design details including the cooling tower type, drift eliminator design details, and materials of construction to the District at least 90 days before the tower is operated. [District Rule 7012]

9. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

10. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20 percent opacity. [District Rule 4101]

11. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

12. No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012]

13. Drift eliminator drift rate shall not exceed 0.0005 percent. [District Rule 2201]

14. Total dissolved solids (TDS) in circulating water shall not exceed 9,000 mg/liter. [District Rule 2201]

15. Compliance with TDS limit shall be determined by cooling water sample analysis by independent laboratory within 60 days of initial operation and quarterly thereafter. [District Rule 1081]

16. Cooling tower circulation water flow rate shall not exceed 95,000 gallons per minute nor 49.41 billion gallons per calendar year. [District Rule 2201]

17. A non-resettable, totalizing mass or volumetric flow meter to measure circulation water flow rate shall be installed, utilized and maintained. [District Rule 2201]

18. PM10 emission rate from the cooling tower shall not exceed 51.6 lb/day. [District Rule 2201]

19. Compliance with the PM10 daily emission limit shall be demonstrated as follows: PM10 lb/day = circulating water recirculation rate x total dissolved solids

concentration in the circulating water x manufacturer's design drift rate. [District Rule 2201]

20. Records of the cooling tower circulating water flow rate and cooling tower water TDS shall be kept at the facility and made readily available for District inspection upon request for 5 years. [District Rule 1070]

Verification: The following verification requirements apply to applicable conditions for permit unit S-7616-29-0:

The project owner shall provide the manufacturer data for cooling tower, including the guarantee data for the drift eliminator, showing compliance with Condition **AQ-14-13** to the CPM and the District at least 90 days prior to cooling tower operation. (Condition **AQ-14-7**)

The project owner shall provide a summary of the water sample analyses showing compliance with the TDS limits in Condition **AQ-14-14**, and daily and annual emissions summaries showing compliance with Condition **AQ-14-18** shall be provided as part of the Annual Compliance Reports (**AQ-SC8**).

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-14** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-14-7** through **-20**)

AQ-15 The following conditions cover permit unit S-7616-30-0.

4,000 MMBTU/HR ELEVATED FLARE WITH 0.5 MMBTU/HR NATURAL GAS-FIRED PILOT, PRIMARILY SERVING GASIFICATION BLOCK (OR EQUIVALENT)

11. Flare pilot shall be fired solely on PUC-quality natural gas. [District Rules 2201 and 2410]

12. Flare shall be equipped with a non-resettable, totalizing flare gas volume flow meter. [District Rules 2201 and 4311]

13. Flare shall be equipped with control valves and relief valves that will maintain a tight shutoff arrangement where no unintended flow is expected, except during actual flaring events. [District Rule 2201]

14. The outlet shall be equipped with an automatic ignition system or shall operate with a pilot flame present at all times when combustible gases are vented through the flare, except during purge periods for automatic-ignition equipped flares. [District Rule 4311, 5.3]

15. Except for flares equipped with a flow-sensing ignition system, a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an equivalent device, capable of continuously detecting at least one pilot flame or

the flare flame is present shall be installed and operated. Request for determination of an alternate equivalent flame sensing or heat sensing device shall be submitted to the District in writing 30 days prior to installation for District approval. [District Rule 4311, 5.4]

16. Flares using a flow-sensing automatic ignition systems and which do not use a continuous flame pilot shall use purge gas for purging. [District Rule 4311, 5.5]

17. A flame shall be present at all times when combustible gases are vented through the flare. [District Rules 2201, 4311, 5.2]

18. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than five minutes in any two hours which is as dark as, or darker than, Ringelmann 1/4 or 5 percent opacity. [District Rule 4101]

19. Maximum amount of gas combusted in the flare during planned flaring shall not exceed any of the following: 21,936 MMBtu/yr of natural gas (including pilot gas); 9,544 MMBtu/yr of unshifted syngas; 43,434 MMBtu/yr of shifted gas. [District Rules 2201 and 2410]

20. Emissions from the flare, during the non-emergency combustion of natural gas, shall not exceed any of the following (based on total gas combusted): PM10: 0.003 lb/MMBtu; NOx (as NO2): 0.068 lb/MMBtu; VOC: 0.0004 lb/MMBtu; CO: 0.08 lb/MMBtu; or SOx: 0.00214 lb/MMBtu. [District Rule 2201]

21. Emissions from the flare, during the non-emergency combustion of syngas and waste gas, shall not exceed any of the following (based on total gas combusted): PM10: 0.000 lb/MMBtu; NOx (as NO2): 0.068 lb/MMBtu; VOC: 0.000 lb/MMBtu; CO: 2.0 lb/MMBtu on unshifted syngas and 0.37 lb/MMBtu on shifted syngas; or SOx: 0.000 lb/MMBtu. [District Rule 2201]

22. Total sulfur content of natural gas combusted shall not exceed 0.75 grain/100 scf. [District Rule 2201]

23. Emissions from the flare shall not exceed any of the following: NOx: 2,399.0 lb/day; SOx: 18.8 lb/day; PM10: 26.4 lb/day; CO: 20,335.2 lb/day; or VOC: 11.4 lb/day. [District Rule 2201]

24. Other than the planned flaring limited in the condition above, this flare shall be operated solely for emergency situations, which are any situations or conditions arising from a sudden and reasonably unforeseen and unpreventable event beyond the control of the operator. Examples include, but are not limited to, not preventable equipment failure, natural disaster, act of war or terrorism, or external power curtailment, excluding a power curtailment due to an interruptible power service agreement from a utility. A flaring event due to improperly designed equipment, lack of preventative maintenance, careless or improper operation, operator error or willful misconduct does not quality as an emergency. An emergency situation requires immediate corrective action to restore safe

operation. A planned flaring event shall not be considered as an emergency. [District Rules 2201 and 4311]

25. A trained observer, as defined in EPA Method 22, shall check visible emissions at least once annually for a period of 15 minutes. If visible emissions are detected at any time during this period, the observation period shall be extended to two hours. A record containing the results of these observations shall be maintained, which also includes company name, process unit, observer's name and affiliation, date, estimated wind speed and direction, sky condition, and the observer's location relative to the source and sun. [District Rule 4311]

26. No less than 90 days prior to installation of the flare, permittee shall submit a flare minimization plan (FMP) that complies with the requirements of Rule 4311 Section 6.5 to the APCO for approval. [District Rules 4311, 6.5 and 2410]

27. Records of the duration of flare operation, amount of gas burned, and the nature of the emergency situation for flare used during an emergency situation shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

28. Copies of approved flare minimization plan pursuant to Rule 4311 Section 6.5 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

29. Flare gas pressure shall not be less than 5 psig when incinerating combustible gasses. [District Rule 4311, 5.6]

30. Copies of monitoring data collected pursuant to Rule 4311 Section 5.10 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

31. The operator shall notify the APCO of an unplanned flaring event within 24 hours after the start of the next business day or within 24 hours of their discovery, whichever occurs first. The notification shall include the flare source identification, the start date and time, and the end date and time. [District Rule 4311, 6.2]

32. The operator of a flare subject to flare minimization plans pursuant to Section 5.8 shall submit an annual report to the APCO that summarizes all Reportable Flaring Events as defined in Rule 4311 Section 3.0 that occurred during the previous 12 month period. The report shall be submitted within 30 days following the end of the twelve month period of the previous year. [District Rule 4311, 6.2]

33. The operator of a flare subject to flare monitoring requirements pursuant to Sections 5.10, 6.6, 6.7, 6.8, 6.9, and 6.10, as appropriate, shall submit an annual report to the APCO as specified in Rule 4311 Section 6.2.3 within 30 days following the end of each 12 month period. [District Rule 4311, 6.2]

34. Pursuant to Rule 4311 Section 6.6, the operator shall monitor vent gas composition using one the methods pursuant to Section 6.6.1 through Section 6.6.5 as appropriate. [District Rule 4311, 6.6]

35. The operator shall monitor the volumetric flows of purge and pilot gases with flow measuring devices. [District Rule 4311, 6.7]

36. If the flare is equipped with a water seal, the operator shall monitor and record the water level and pressure of the water seal that services each flare daily. [District Rule 4311, 6.8]

37. Periods of flare monitoring system in operation greater than 24 continuous hours shall be reported by the following working day, followed by notification of resumption of monitoring. Periods of inoperation of monitoring equipment shall not exceed 14 days per any 18-consecutive-month period. Periods of flare monitoring system inoperation do not include the periods when the system feeding the flare is not operating. [District Rule 4311, 6.9]

38. During periods of inoperation of continuous analyzers or auto-samplers installed pursuant to Section 6.6, operators responsible for monitoring shall take one sample within 30 minutes of the commencement of flaring, from the flare header or from an alternate location at which samples are representative of vent gas composition and have samples analyzed pursuant to Section 6.3.4. During periods of inoperation of flow monitors required by Section 5.10, flow shall be calculated using good engineering practices. [District Rule 4311, 6.9]

39. Operator shall maintain and calibrate all required monitors and recording devices in accordance with the applicable manufacturer's specifications. In order to claim that a manufacturer's specification is not applicable, the person responsible for emissions must have, and follow, a written maintenance policy that was developed for the device in question. The written policy must explain and justify the difference between the written procedure and the manufacturer's procedure. [District Rule 4311, 6.9]

40. All in-line continuous analyzer and flow monitoring data must be continuously recorded by an electronic data acquisition system capable of one-minute averages. Flow monitoring data shall be recorded as one-minute averages. [District Rule 4311, 6.9]

41. The owner or operator shall notify the District of any emergency use of the flare within one hour after confirmation that an actual flaring event has occurred, unless the owner or operator demonstrates to the District's satisfaction that a longer notification period was necessary. However, in the event that confirmation of an actual flaring event cannot be made, then the owner or operator shall notify the District no more than 3 hours after an alarm indicates that a flaring event may have occurred, unless the owner or operator demonstrates to the District's satisfaction that a longer notification period was necessary. [District Rule 1070]

42. The permittee shall report to the District in writing within ten days following the emergency use of the flare. The report shall include 1) a statement that the failure or malfunction has been corrected, the date corrected, and proof of correction; 2) a specific statement of the reason or cause for the occurrence; 3) a description of the corrective measures undertaken and/or to be undertaken to avoid such an occurrence in the future; and 4) an estimate of the emissions caused by the emergency use, specifically including duration of flare operation and amount of gas burned. [District Rules 1070 and 4311]

43. The flare shall be inspected during operation for visible emissions, using EPA Method 22. If visible emissions are observed, corrective action shall be taken. If visible emissions cannot be eliminated, an EPA Method 9 test shall be conducted within 72 hours. [District Rule 2201]

44. The permittee shall keep accurate daily records of the amount of gas combusted in the flare, gas type, reason for flaring, hours of operation, the sulfur content and heat content of the gas combusted. The permittee shall keep these records for a period of at least five years and shall make such records available for District inspection upon request. [District Rules 2201 and 4311]

45. Permittee shall record the sulfur content and the quantity of gas flared and shall demonstrate compliance with the SOx emission limit. [District Rule 2201]

46. The permittee shall obtain written District approval for the use of any equivalent equipment not specifically approved by this Determination of Compliance. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

47. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

48. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Determination of Compliance. [District Rule 2201]

49. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

50. The air quality modeled impacts of the proposed alternative equivalent equipment shall not result in any more adverse impacts than the equipment it replaces. [District Rule 2201]

51. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070]

__**Verification:**__ The following verification requirements apply to applicable conditions for permit unit S-7616-30-0:

The project owner shall provide a summary of: 1) planned and unplanned flaring events with their duration and estimated heat content throughput and annual emissions estimates (Conditions **AQ-15-19**, **-20**, **-21**, **-23**); 2) visible emissions monitoring (Condition **AQ-15-43**); and 3) non-compliance events and associated corrective maintenance (Condition **AQ-15-51**) in the Annual Compliance Reports (**AQ-SC8**).

The project owner shall provide a flare minimization plan to the District for approval and CPM for review at least 90 days before installation of the flare (Condition **AQ-15-26**).

The project owner shall provide notification of emergency flaring events to the CPM and District as required in Condition AQ-15-41.

The project owner shall submit the written request for the use of alternate equipment, if necessary, to both the District and CPM for approval in accordance with, and that meets the standards of, Conditions **AQ-15-46** through **-50**.

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-15** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-15-11** through **-51**)

AQ-16 The following conditions cover permit unit S-7616-31-0.

800 MMBTU/HR ELEVATED FLARE WITH 0.3 MMBTU/HR NATURAL GAS FIRED PILOT, PRIMARILY SERVING SULFUR RECOVERY UNIT (OR EQUIVALENT)

11. Flare pilot shall be fired solely on PUC-quality natural gas. [District Rules 2201 and 2410]

12. Flare shall be equipped with a non-resettable, totalizing flare gas volume flow meter. [District Rules 2201 and 4311]

13. Flare shall be equipped with control valves and relief valves that will maintain a tight shutoff arrangement where no unintended flow is expected, except during actual flaring events. [District Rule 2201]

14. The outlet shall be equipped with an automatic ignition system or shall operate with a pilot flame present at all times when combustible gases are vented through the flare, except during purge periods for automatic-ignition equipped flares. [District Rule 4311, 5.3 and 40 CFR 60.18]

15. Except for flares equipped with a flow-sensing ignition system, a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an equivalent device, capable of continuously detecting at least one pilot flame or the flare flame, is present, shall be installed and operated. Request for determination of an alternate equivalent flame sensing or heat sensing device shall be submitted to the District in writing 30 days prior to installation for District approval. [District Rule 4311, 5.4 and 40 CFR 60.18]

16. Flares using a flow-sensing automatic ignition systems and which do not use a continuous flame pilot shall use purge gas for purging. [District Rule 4311, 5.5]

17. A flame shall be present at all times when combustible gases are vented through the flare. [District Rules 2201, 4311, 5.2 and 40 CFR 60.18(c)(2)]

18. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than five minutes in any two hours which is as dark as, or darker than, Ringelmann 1/4 or 5 percent opacity. [District Rule 4101 and 40 CFR 60.18]

19. Total time of planned flaring shall not exceed 40 hours per calendar year. [District Rule 2201 and 2410]

20. During planned flaring events, no more than 36 MMBtu/hr shall be combusted. [District Rules 2201 and 2410]

21. Emissions from the flare shall not exceed any of the following (based on total gas combusted): PM10: 0.003 lb/MMBtu; NOx (as NO2): 0.068 lb/MMBtu; VOC: 0.0013 lb/MMBtu; or CO: 0.08 lb/MMBtu. [District Rule 2201]

22. SOx emissions from the flare shall not exceed 0.00214 lb/MMBtu during pilot gas combustion nor 18.4 lb/hr during other non-emergency combustion. [District Rule 2201]

23. Total sulfur content of natural gas combusted shall not exceed 0.75 grain/100 scf. [District Rule 2201]

24. Other than the planned flaring limited in the condition above, this flare shall be operated solely for emergency situations, which are any situations or conditions arising from a sudden and reasonably unforeseen and unpreventable event beyond the control of the operator. Examples include, but are not limited to, not preventable equipment failure, natural disaster, act of war or terrorism, or external power curtailment, excluding a power curtailment due to an interruptible power service agreement from a utility. A flaring event due to improperly designed equipment, lack of preventative maintenance, careless or improper operation, operator error or willful misconduct does not quality as an emergency. An emergency situation requires immediate corrective action to restore safe operation. A planned flaring event shall not be considered as an emergency. [District Rules 2201 and 4311]

25. A trained observer, as defined in EPA Method 22, shall check visible emissions at least once annually for a period of 15 minutes. If visible emissions are detected at any time during this period, the observation period shall be extended to two hours. A record containing the results of these observations shall be maintained, which also includes company name, process unit, observer's name and affiliation, date, estimated wind speed and direction, sky condition, and the observer's location relative to the source and sun. [District Rule 4311]

26. No less than 90 days prior to installation of the flare, permittee shall submit a flare minimization plan (FMP) that complies with the requirements of Rule 4311 Section 6.5 to the APCO for approval. [District Rules 4311, 6.5 and 2410]

27. Records of the duration of flare operation, amount of gas burned, and the nature of the emergency situation for flare used during an emergency, situation shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

28. Copies of approved flare minimization plan pursuant to Rule 4311 Section 6.5 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

29. Copies of compliance determination pursuant to 40 CFR 60.18 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1 and 40 CFR 60.18]

30. Copies of monitoring data collected pursuant to Rule 4311 Section 5.10 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

31. The operator shall notify the APCO of an unplanned flaring event within 24 hours after the start of the next business day or within 24 hours of their discovery, whichever occurs first. The notification shall include the flare source identification, the start date and time, and the end date and time. [District Rule 4311, 6.2]

32. The operator of a flare subject to flare minimization plans pursuant to Section 5.8 shall submit an annual report to the APCO that summarizes all Reportable Flaring Events as defined in Rule 4311 Section 3.0 that occurred during the previous 12 month period. The report shall be submitted within 30 days following the end of the twelve month period of the previous year. [District Rule 4311, 6.2]

33. The operator of a flare subject to flare monitoring requirements pursuant to Sections 5.10, 6.6, 6.7, 6.8, 6.9, and 6.10, as appropriate, shall submit an annual report to the APCO as specified in Rule 4311 Section 6.2.3 within 30 days following the end of each 12 month period. [District Rule 4311, 6.2]

34. Pursuant to Rule 4311 Section 6.6, the operator shall monitor vent gas composition using one the methods pursuant to Section 6.6.1 through Section 6.6.5 as appropriate. [District Rule 4311, 6.6]

35. The operator shall monitor the volumetric flows of purge and pilot gases with flow measuring devices. [District Rule 4311, 6.7]

36. If the flare is equipped with a water seal, the operator shall monitor and record the water level and pressure of the water seal that services each flare daily. [District Rule 4311, 6.8]

37. Periods of flare monitoring system in operation greater than 24 continuous hours shall be reported by the following working day, followed by notification of resumption of monitoring. Periods of inoperation of monitoring equipment shall not exceed 14 days per any 18-consecutive-month period. Periods of flare monitoring system inoperation do not include the periods when the system feeding the flare is not operating. [District Rule 4311, 6.9]

38. During periods of inoperation of continuous analyzers or auto-samplers installed pursuant to Section 6.6, operators responsible for monitoring shall take one sample within 30 minutes of the commencement of flaring, from the flare header or from an alternate location at which samples are representative of vent gas composition, and have samples analyzed pursuant to Section 6.3.4. During periods of inoperation of flow monitors required by Section 5.10, flow shall be calculated using good engineering practices. [District Rule 4311, 6.9]

39. Operator shall maintain and calibrate all required monitors and recording devices in accordance with the applicable manufacturer's specifications. In order to claim that a manufacturer's specification is not applicable, the person responsible for emissions must have, and follow, a written maintenance policy that was developed for the device in question. The written policy must explain and justify the difference between the written procedure and the manufacturer's procedure. [District Rule 4311, 6.9]

40. All in-line continuous analyzer and flow monitoring data must be continuously recorded by an electronic data acquisition system capable of one-minute averages. Flow monitoring data shall be recorded as one-minute averages. [District Rule 4311, 6.9]

41. The owner or operator shall notify the District of any emergency use of the flare within one hour after confirmation that an actual flaring event has occurred, unless the owner or operator demonstrates to the District's satisfaction that a longer notification period was necessary. However, in the event that confirmation of an actual flaring event cannot be made, then the owner or operator shall notify the District no more than 3 hours after an alarm indicates that a flaring event may have occurred, unless the owner or operator demonstrates to the District's satisfaction that a longer notification period was necessary. [District Rule 1070]

42. The permittee shall report to the District in writing within ten days following the emergency use of the flare. The report shall include 1) a statement that the failure or malfunction has been corrected, the date corrected, and proof of correction; 2) a specific statement of the reason or cause for the occurrence; 3) a description of the corrective measures undertaken and/or to be undertaken to avoid such an occurrence in the future; and 4) an estimate of the emissions caused by the emergency use, specifically including duration of flare operation and amount of gas burned. [District Rules 1070 and 4311]

43. Open flares (air-assisted, steam-assisted, or non-assisted) in which the flare gas pressure is less than 5 psig shall be operated in such a manner that meets the

provisions of 40 CFR 60.18. The requirements of this section shall not apply to Coanda effect flares. [District Rule 4311, 5.6]

44. No less than 90 days prior to installation, the applicant shall demonstrate to the District how compliance with 40 CFR 60.18 (c)(3) shall be satisfied. Compliance with either subparts (c)(3)(i), or (c)(3)(ii) and (c)(4) shall be demonstrated to the District. [40 CFR 60.18 (c)(3)]

45. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(i), a non-assisted flare shall have a diameter of 3 inches or greater, have a minimum hydrogen content of 8.0 percent by volume, and be designed for and operated with an exit velocity less than 122 ft/sec and less than the velocity Vmax, as determined by the equation specified in paragraph 40 CFR 60.18 (c)(3)(i)(A). [40 CFR 60.18]

46. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), the heating value of the gas combusted in the flare shall be at least 200 Btu/scf. [District Rule 4311 and 40 CFR 60.18]

47. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), non-assisted flares may be operated with an exit velocity equal to or greater than 60 ft/sec, but less than 400 ft/sec, if the net heating value of the gas being combusted is greater than 1,000 Btu/scf. [40 CFR 60.18]

48. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), non-assisted flares shall be operated with an exit velocity less than 60 ft/sec, except as provided in 40 CFR 60.18 (c)(4)(ii) and (iii). [40 CFR 60.18]

49. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), non-assisted flares may be operated with an exit velocity less than the maximum velocity Vmax, as determined by the methods specified in 40 CFR 60.18 (f)(5), and less than 400 ft/sec. [40 CFR 60.18]

50. The net heating value of the gas being combusted the flare shall be calculated pursuant to 40 CFR 60.18(f)(3) or by using EPA Method 18, ASTM D1946, and ASTM D2382 if published values are not available or cannot be calculated. [40 CFR 60.18]

51. The flare shall be inspected during operation for visible emissions, using EPA Method 22. If visible emissions are observed, corrective action shall be taken. If visible emissions cannot be eliminated, an EPA Method 9 test shall be conducted within 72 hours. [District Rule 2201 and 40 CFR 60.18]

52. The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip. [40 CFR 60.18]

53. Upon request, operator shall make available to the APCO the compliance determination records that demonstrate compliance with the provisions of 40 CFR 60.18. [District Rule 4311, 6.1]

54. Semi-annual reports of all periods without the presence of a flare pilot flame shall be furnished to the District Compliance Division and EPA. [District Rule 4001 and 40 CFR 60.115b(d)(3)]

55. The permittee shall keep accurate daily records of the amount of gas combusted in the flare, gas type, reason for flaring, hours of operation, the sulfur content and heat content of the gas combusted, and records demonstrating compliance with the provisions of 40 CFR 60.18, (c)(3) through (c)(5). The permittee shall keep these records for a period of at least five years and shall make such records available for District inspection upon request. [District Rules 2201, 4311, 40 CFR 60.18]

56. Permittee shall record the sulfur content and the quantity of gas flared and shall demonstrate compliance with the SOx emission limit. [District Rule 2201]

57. The permittee shall obtain written District approval for the use of any equivalent equipment not specifically approved by this Determination of Compliance. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

58. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

59. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Determination of Compliance. [District Rule 2201]

60. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

61. The air quality modeled impacts of the proposed alternative equivalent equipment shall not result in any more adverse impacts than the equipment it replaces. [District Rule 2201]

62. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070]

Verification: The following verification requirements apply to applicable conditions for permit unit S-7616-31-0:

The project owner shall provide a summary of: 1) planned and unplanned flaring events with their duration and estimated heat content throughput and annual emissions estimates (Conditions **AQ-16-19** through **-22**); 2) visible emissions monitoring (Condition **AQ-16-51**); and 3) non-compliance events and associated corrective maintenance (Condition **AQ-16-62**) in the Annual Compliance Reports (**AQ-SC8**).

The project owner shall provide a flare minimization plan to the District for approval and CPM for review at least 90 days before installation of the flare (Condition **AQ-16-26**).

The project owner shall submit the written request for the use of alternate equipment, if necessary, to both the District and CPM for approval in accordance with, and that meets the standards of, Conditions **AQ-16-57** through **-61**.

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-16** conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-16-11** through **-62**)

AQ-17 The following conditions cover permit unit S-7616-32-0.

5,500 MMBTU/HR ELEVATED FLARE WITH 0.3 MMBTU/HR NATURAL GAS-FIRED PILOT, PRIMARILY SERVING RECTISOL UNIT (OR EQUIVALENT)

11. Flare pilot shall be fired solely on PUC-quality natural gas. [District Rules 2201, 2410]
12. Flare shall be equipped with a non-resettable, totalizing flare gas volume flow meter. [District Rules 2201 and 4311]
13. Flare shall be equipped with control valves and relief valves that will maintain a tight shutoff arrangement where no unintended flow is expected, except during actual flaring events. [District Rule 2201]
14. The outlet shall be equipped with an automatic ignition system or shall operate with a pilot flame present at all times when combustible gases are vented through the flare, except during purge periods for automatic-ignition equipped flares. [District Rule 4311, 5.3 and 40 CFR 60.18]
15. Except for flares equipped with a flow-sensing ignition system, a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an equivalent device, capable of continuously detecting at least one pilot flame or the flare flame is present shall be installed and operated. Request for determination of an alternate equivalent flame sensing or heat sensing device shall be submitted to the District in writing 30 days prior to installation for District approval. [District Rule 4311, 5.4 and 40 CFR 60.18]
16. Flares using a flow-sensing automatic ignition systems and which do not use a continuous flame pilot shall use purge gas for purging. [District Rule 4311, 5.5]

17. A flame shall be present at all times when combustible gases are vented through the flare. [District Rules 2201, 4311, 5.2 and 40 CFR 60.18(c)(2)]

18. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than five minutes in any two hours which is as dark as, or darker than, Ringelmann 1/4 or 5 percent opacity. [District Rule 4101 and 40 CFR 60.18]

19. Total time of planned flaring shall not exceed 8 hours per day nor 40 hours per calendar year. [District Rules 2201 and 2410]

20. During planned flaring events, no more than 430 MMBtu/hr shall be combusted. [District Rule 2201 and 2410]

21. Emissions from the flare during pilot and other non-emergency operation shall not exceed any of the following: PM10: 0.003 lb/MMBtu; NOx (as NO2): 0.068 lb/MMBtu; VOC: 0.0013 lb/MMBtu; or CO: 0.08 lb/MMBtu. [District Rule 2201]

22. SOx emissions from the flare shall not exceed 0.00214 lb/MMBtu during pilot gas combustion nor 15.0 lb/hr during other non-emergency combustion. [District Rule 2201]

23. Total sulfur content of natural gas combusted shall not exceed 0.75 grain/100 scf. [District Rule 2201]

24. Other than the planned flaring limited in the condition above, this flare shall be operated solely for emergency situations, which are any situations or conditions arising from a sudden and reasonably unforeseen and unpreventable event beyond the control of the operator. Examples include, but are not limited to, not preventable equipment failure, natural disaster, act of war or terrorism, or external power curtailment, excluding a power curtailment due to an interruptible power service agreement from a utility. A flaring event due to improperly designed equipment, lack of preventative maintenance, careless or improper operation, operator error or willful misconduct does not quality as an emergency. An emergency situation requires immediate corrective action to restore safe operation. A planned flaring event shall not be considered as an emergency. [District Rules 2201 and 4311]

25. A trained observer, as defined in EPA Method 22, shall check visible emissions at least once annually for a period of 15 minutes. If visible emissions are detected at any time during this period, the observation period shall be extended to two hours. A record containing the results of these observations shall be maintained, which also includes company name, process unit, observer's name and affiliation, date, estimated wind speed and direction, sky condition, and the observer's location relative to the source and sun. [District Rule 4311]

26. No less than 90 days prior to installation of the flare, permittee shall submit a flare minimization plan (FMP) that complies with the requirements of Rule 4311 Section 6.5 to the APCO for approval. [District Rules 4311, 6.5 and 2410]

27. Records of the duration of flare operation, amount of gas burned, and the nature of the emergency situation for flare used during an emergency situation shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

28. Copies of approved flare minimization plan pursuant to Rule 4311 Section 6.5 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

29. Copies of compliance determination pursuant to 40 CFR 60.18 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1 and 40 CFR 60.18]

30. Copies of monitoring data collected pursuant to Rule 4311 Section 5.10 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

31. The operator shall notify the APCO of an unplanned flaring event within 24 hours after the start of the next business day or within 24 hours of their discovery, whichever occurs first. The notification shall include the flare source identification, the start date and time, and the end date and time. [District Rule 4311, 6.2]

32. The operator of a flare subject to flare minimization plans pursuant to Section 5.8 shall submit an annual report to the APCO that summarizes all Reportable Flaring Events as defined in Rule 4311 Section 3.0 that occurred during the previous 12 month period. The report shall be submitted within 30 days following the end of the twelve month period of the previous year. [District Rule 4311, 6.2]

33. The operator of a flare subject to flare monitoring requirements pursuant to Sections 5.10, 6.6, 6.7, 6.8, 6.9, and 6.10, as appropriate, shall submit an annual report to the APCO as specified in Rule 4311 Section 6.2.3 within 30 days following the end of each 12 month period. [District Rule 4311, 6.2]

34. Pursuant to Rule 4311 Section 6.6, the operator shall monitor vent gas composition using one the methods pursuant to Section 6.6.1 through Section 6.6.5 as appropriate. [District Rule 4311, 6.6]

35. The operator shall monitor the volumetric flows of purge and pilot gases with flow measuring devices. [District Rule 4311, 6.7]

36. If the flare is equipped with a water seal, the operator shall monitor and record the water level and pressure of the water seal that services each flare daily. [District Rule 4311, 6.8]

37. Periods of flare monitoring system in operation greater than 24 continuous hours shall be reported by the following working day, followed by notification of resumption of monitoring. Periods of inoperation of monitoring equipment shall not exceed 14 days per any 18-consecutive-month period. Periods of flare

monitoring system inoperation do not include the periods when the system feeding the flare is not operating. [District Rule 4311, 6.9]

38. During periods of inoperation of continuous analyzers or auto-samplers installed pursuant to Section 6.6, operators responsible for monitoring shall take one sample within 30 minutes of the commencement of flaring, from the flare header or from an alternate location at which samples are representative of vent gas composition and have samples analyzed pursuant to Section 6.3.4. During periods of inoperation of flow monitors required by Section 5.10, flow shall be calculated using good engineering practices. [District Rule 4311, 6.9]

39. Operator shall maintain and calibrate all required monitors and recording devices in accordance with the applicable manufacturer's specifications. In order to claim that a manufacturer's specification is not applicable, the person responsible for emissions must have, and follow, a written maintenance policy that was developed for the device in question. The written policy must explain and justify the difference between the written procedure and the manufacturer's procedure. [District Rule 4311, 6.9]

40. All in-line continuous analyzer and flow monitoring data must be continuously recorded by an electronic data acquisition system capable of one-minute averages. Flow monitoring data shall be recorded as one-minute averages. [District Rule 4311, 6.9]

41. The owner or operator shall notify the District of any emergency use of the flare within one hour after confirmation that an actual flaring event has occurred, unless the owner or operator demonstrates to the District's satisfaction that a longer notification period was necessary. However, in the event that confirmation of an actual flaring event cannot be made, then the owner or operator shall notify the District no more than 3 hours after an alarm indicates that a flaring event may have occurred, unless the owner or operator demonstrates to the District's satisfaction that a longer notification period was necessary. [District Rule 1070]

42. The permittee shall report to the District in writing within ten days following the emergency use of the flare. The report shall include 1) a statement that the failure or malfunction has been corrected, the date corrected, and proof of correction; 2) a specific statement of the reason or cause for the occurrence; 3) a description of the corrective measures undertaken and/or to be undertaken to avoid such an occurrence in the future; and 4) an estimate of the emissions caused by the emergency use, specifically including duration of flare operation and amount of gas burned. [District Rules 1070 and 4311]

43. Open flares (air-assisted, steam-assisted, or non-assisted) in which the flare gas pressure is less than 5 psig shall be operated in such a manner that meets the provisions of 40 CFR 60.18. The requirements of this section shall not apply to Coanda effect flares. [District Rule 4311, 5.6]

44. No less than 90 days prior to installation, the applicant shall demonstrate to the District how compliance with 40 CFR 60.18 (c)(3) shall be satisfied. Compliance

with either subparts (c)(3)(i), or (c)(3)(ii) and (c)(4) shall be demonstrated to the District. [40 CFR 60.18 (c)(3)]

45. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(i), a non-assisted flare shall have a diameter of 3 inches or greater, have a minimum hydrogen content of 8.0 percent by volume, and be designed for and operated with an exit velocity less than 122 ft/sec and less than the velocity Vmax, as determined by the equation specified in paragraph 40 CFR 60.18 (c)(3)(i)(A). [40 CFR 60.18]

46. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), the heating value of the gas combusted in the flare shall be at least 200 Btu/scf. [District Rule 4311 and 40 CFR 60.18]

47. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), non-assisted flares may be operated with an exit velocity equal to or greater than 60 ft/sec, but less than 400 ft/sec, if the net heating value of the gas being combusted is greater than 1,000 Btu/scf. [40 CFR 60.18]

48. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), non-assisted flares shall be operated with an exit velocity less than 60 ft/sec, except as provided in 40 CFR 60.18 (c)(4)(ii) and (iii). [40 CFR 60.18]

49. If the permittee opts to comply with 40 CFR 60.18 (c)(3)(ii) and (c)(4), non-assisted flares may be operated with an exit velocity less than the velocity Vmax, as determined by the methods specified in 40 CFR 60.18 (f)(5), and less than 400 ft/sec. [40 CFR 60.18]

50. The net heating value of the gas being combusted the flare shall be calculated pursuant to 40 CFR 60.18(f)(3) or by using EPA Method 18, ASTM D1946, and ASTM D2382 if published values are not available or cannot be calculated. [40 CFR 60.18]

51. The flare shall be inspected during operation for visible emissions, using EPA Method 22. If visible emissions are observed, corrective action shall be taken. If visible emissions cannot be eliminated, an EPA Method 9 test shall be conducted within 72 hours. [District Rule 2201 and 40 CFR 60.18]

52. The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip. [40 CFR 60.18]

53. Upon request, operator shall make available to the APCO the compliance determination records that demonstrate compliance with the provisions of 40 CFR 60.18. [District Rule 4311, 6.1]

54. Semi-annual reports of all periods without the presence of a flare pilot flame shall be furnished to the District Compliance Division and EPA. [District Rule 4001 and 40 CFR 60.115b(d)(3)]

55. The permittee shall keep accurate daily records of the amount of gas combusted in the flare, gas type, reason for flaring, hours of operation, the sulfur content and heat content of the gas combusted, and records demonstrating compliance with the provisions of 40 CFR 60.18, (c)(3) through (c)(5). The permittee shall keep these records for a period of at least five years and shall make such records available for District inspection upon request. [District Rules 2201, 4311, 40 CFR 60.18]

56. Permittee shall record the sulfur content and the quantity of gas flared and shall demonstrate compliance with the SOx emission limit. [District Rule 2201]

57. The permittee shall obtain written District approval for the use of any equivalent equipment not specifically approved by this Determination of Compliance. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

58. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

59. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Determination of Compliance. [District Rule 2201]

60. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

61. The air quality modeled impacts of the proposed alternative equivalent equipment shall not result in any more adverse impacts than the equipment it replaces. [District Rule 2201]

62. {3246} All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070]

<u>Verification:</u> The following verification requirements apply to applicable conditions for permit unit S-7616-32-0:

The project owner shall provide a summary of: 1) planned and unplanned flaring events with their duration and estimated heat content throughput and annual emissions estimates (Conditions **AQ-17-19** through **-22**); 2) visible emissions monitoring (Condition **AQ-17-51**); and 3) non-compliance events and associated corrective maintenance (Condition **AQ-17-62**) in the Annual Compliance Reports (**AQ-SC8**).

The project owner shall provide a flare minimization plan to the District for approval and CPM for review at least 90 days before installation of the flare (Condition **AQ-17-26**).

The project owner shall submit the written request for the use of alternate equipment, if necessary, to both the District and CPM for approval in accordance with, and that meets the standards of, Conditions **AQ-17-57** through **-61**.

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-17** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-17-11** through **-62**)

AQ-18 The following conditions cover permit unit S-7616-33-0.

AMMONIA SYNTHESIS UNIT CONSISTING OF: ONE 56.0 MMBTU/HR NATURAL GAS-FIRED AMMONIA STARTUP HEATER EQUIPPED WITH FOUR LOW-NOX BURNERS, EACH RATED AT 14.0 MMBTU/HR (OR EQUIVALENT); AMMONIA SYNTHESIS CONVERTER; SEPARATORS; ELECTRIC SYNGAS COMPRESSOR; ELECTRIC AMMONIA REFRIGERATION COMPRESSOR; AMMONIA ACCUMULATOR; AMMONIA REFRIGERATION SYSTEM; COLD LIQUID AMMONIA STORAGE SYSTEM; AMMONIA RECOVERY UNIT

11. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20 percent opacity. [District Rule 4101]

12. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

13. Heater shall be fired solely on PUC-quality natural gas. [District Rules 2201, 2410, and 4320]

14. Duration of startup and shutdown of heater shall not exceed 2 hours each per occurrence. The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. The operator shall maintain records of the duration of startup and shutdown. [District Rules 4305, 4306, and 4320]

15. Emissions from heater, except during startup or shutdown, shall not exceed any of the following limits: NOx (as NO2): 9.0 ppmvd @ 3 percent O2 or 0.011 lb/MMBtu, SOx (as SO2): 0.00285 lb/MMBtu, PM10: 0.005 lb/MMBtu, CO: 50 ppmvd @ 3 percent O2 or 0.037 lb/MMBtu, or VOC: 0.0040 lb/MMBtu. [District Rules 2201, 4305, 4306 and 4320]

16. The annual heat input of the heater shall not exceed 7.84 billion Btu per calendar year. [District Rules 2201 and 2410]

17. Pursuant to Rule 4320, the operator shall pay an annual emission fee to the District for NOx emissions from this heater for the previous calendar year.

Payments are due by July 1 of each year. Payments shall continue annually until either the unit is permanently removed from service in the District or the operator demonstrates compliance with the applicable NOx emission limit listed in Rule 4320. [District Rule 4320]

18. A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of natural gas combusted in the unit shall be installed, utilized and maintained. [District Rule 2201]

19. Permittee shall maintain records of the annual heat input of the unit. [District Rules 1070, 2201]

20. The permittee shall monitor and record the stack concentration of NOX, CO, and O2 at least once every month (in which a source test is not performed) using a portable analyzer that meets District specifications. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305, 4306, and 4320]

21. If either the NOX or CO concentrations corrected to 3 percent O2, as measured by the portable analyzer, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 4305, 4306, and 4320]

22. All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306, and 4320]

23. The permittee shall maintain records of: (1) the date and time of NOX, CO, and O2 measurements, (2) the O2 concentration in percent by volume and the measured NOX and CO concentrations corrected to 3 percent O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and

(5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305, 4306, and 4320]

24. This unit shall be tested for compliance with the NOx and CO emissions limits at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305, 4306, and 4320]

25. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

26. Source test results for NOx emissions shall be submitted to the District as NOx, NO, and NO2 when available. [District Rule 2410]

27. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

28. The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306, and 4320]

29. All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the DOC. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305 and 4306]

30. The following test methods shall be used: NOx (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19, CO (ppmv) - EPA Method 10 or 10B or ARB Method 100, stack gas oxygen - EPA Method 3 or 3A or ARB Method 100, SOx (lb/MMBtu) - ARB Method 100 or EPA Method 6, 6C or fuel gas sulfur content analysis and EPA Method 19, fuel gas sulfur content - EPA Method 11 or 15, ASTM D3246 or double GC for H2S and mercaptans performed in a laboratory, fuel gas hhv - ASTM D1826 or D1945 in conjunction with ASTM D3588. [District Rules 4305, 4306 and 4320]

31. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every month (in which a source test is not performed) using a portable analyzer that meets District specifications. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305, 4306, and 4320]

32. If either the NOx or CO concentrations corrected to 3 percent O2, as measured by the portable analyzer, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 4305, 4306, and 4320]

33. All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the DOC. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306, and 4320]

34. The permittee shall maintain records of: (1) the date and time of NOx, CO, and O2 measurements, (2) the O2 concentration in percent by volume and the measured NOx and CO concentrations corrected to 3 percent O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305, 4306, and 4320]

35. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305, 4306, and 4320]

36. All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 2201, 4305, 4306, and 4320]

37. Components attributed to this unit shall include those components serving the following process streams: low NH3 concentration, moderate NH3 concentration, high NH3 concentration, low CO_2 concentration, moderate CO_2 concentration, high CO_2 concentration, NO_2, nitric acid (HNO3), and PSA off gas. [District Rule 2201]

38. Fugitive VOC emission rate from the unit shall not exceed 0.0 lb/day based on the component count and emission factors from EPA document Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017), Table 2-1, SOCMI

Average Emissions Factors and the applicable control efficiency for those components subject to a leak detection and repair (LDAR) program. Components serving the following streams associated with this unit shall be subject to a leak detection and repair (LDAR) program: low NH3 concentration, moderate NH3 concentration, high NH3 concentration, low CO_2 concentration, moderate CO_2 concentration, high CO_2 concentration, NO_2, nitric acid (HNO3), and PSA off gas. The following control efficiencies in Table 5-2 of the EPA document shall apply to those components under an LDAR program: gas valves: 92 percent; light liquid valves: 88 percent; light liquid pump seals: 75 percent; and connectors: 93 percent. [District Rules 2201 and 2410]

39. Fugitive CO emission rate from the unit shall not exceed 5.9 lb/day based on the component count, CO percentage in the fluid stream, emission factors from Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017), Table 2-1, SOCMI Average Emissions Factors and the applicable control efficiency for those components subject to a leak detection and repair (LDAR) program. [District Rule 2201]

40. Permittee shall maintain with the DOC an accurate fugitive component count and the resulting emissions calculated using above specified leak rates and control efficiencies. [District Rule 2201]

41. The VOC content of the gas in the following streams shall not exceed 10 percent by weight: low NH3 concentration, moderate NH3 concentration, high NH3 concentration, low CO_2 concentration, moderate CO_2 concentration, high CO_2 concentration, NO_2, nitric acid (HNO3), and PSA off gas. [District Rule 2201]

42. Operator shall conduct quarterly gas sampling to qualify for exemption from fugitive component counts for those components handling fluids with VOC content equal to or less than 10 percent by weight. If gas samples are equal to or less than 10 percent VOC by weight for 8 consecutive quarterly samplings, sampling frequency shall only be required annually. [District Rule 2201]

43. VOC content of gas streams shall be determined by ASTM D1945, EPA Method 18 referenced as methane, or equivalent test method with prior District approval. [District Rule 2201]

44. All sampling connections, open-ended valves, and lines shall be equipped with two closed valves or be sealed with blind flanges, caps, or threaded plugs except during actual use. [District Rule 2201]

45. Permittee shall maintain records of the VOC content test results for a period of five years and make such records available for inspection upon request. [District Rule 1070]

46. For valves and connectors attributed to this unit, a leak shall be defined as a reading of methane in excess of 100 ppmv above background when measured per EPA Method 21. For pump and compressor seals attributed to this unit, a leak shall be defined as a reading of methane in excess of 500 ppmv above background when measure per EPA Method 21. [District Rule 2201]

47. The operator shall audio-visually inspect for leaks all accessible operating pumps, compressors and Pressure Relief Devices (PRDs) in service at least once every 24 hours, except when operators do not report to the facility for that given 24 hours. Any identified leak that cannot be immediately repaired shall be reinspected within 24 hours using a portable analyzer. If a leak is found, it shall be repaired as soon as practical but not later than the time frame specified in Rule 4455 Table 3. [District Rule 2201]

48. The operator shall inspect all components at least once every calendar quarter, except for inaccessible components, unsafe-to-monitor components and pipes. Inaccessible components, unsafe-to-monitor components and pipes shall be inspected in accordance with the requirements set forth in Rule 4455 Sections 5.2.5, 5.2.6, and 5.2.7. New, replaced, or repaired fittings, flanges and threaded connections shall be inspected immediately after being placed into service. Components shall be inspected using EPA Method 21. [District Rule 2201]

49. The operator may apply for a written approval from the APCO to change the inspection frequency from quarterly to annually for a component type, provided the operator meets all the criteria specified in Rule 4455 Sections 5.2.8.1 through 5.2.8.3. This approval shall apply to accessible component types, specifically designated by the APCO, except pumps, compressors, and PRDs which shall continue to be inspected on a quarterly basis. [District Rule 2201]

50. An annual inspection frequency approved by the APCO shall revert to quarterly inspection frequency for a component type if either the operator inspection or District inspection demonstrates that a violation of the provisions of Rule 4455 Sections 5.1, 5.2 and 5.3 of the rule exists for that component type, or the APCO issued a Notice of Violation for violating any of the provisions of Rule 4455 during the annual inspection period for that component type. When the inspection frequency changes from annual to quarterly inspections, the operator shall notify the APCO in writing within five (5) calendar days after changing the inspection frequency, giving the reason(s) and date of change to quarterly inspection frequency. [District Rule 2201]

51. The operator shall initially inspect a process PRD that releases to the atmosphere as soon as practicable but not later than 24 hours after the time of the release. To insure that the process PRD is operating properly, and is leak-free, the operator shall re-inspect the process PRD not earlier than 24 hours after the initial inspection but not later than 15 calendar days after the date of the release using EPA Method 21. If the process PRD is found to be leaking at either inspection, the PRD leak shall be treated as if the leak was found during quarterly operator inspections. [District Rule 2201]

52. Except for process PRD, a component shall be inspected within 15 calendar days after repairing the leak or replacing the component using EPA Method 21. [District Rule 2201]

53. Upon detection of a leaking component, the operator shall affix to that component a weatherproof readily visible tag that contains the information

specified in Rule 4455 Section 5.3.3. The tag shall remain affixed to the component until the leaking component has been repaired or replaced; has been re-inspected using EPA Method 21; and is found to be in compliance with leak, inspection, and maintenance requirements. [District Rule 2201]

54. An operator shall minimize all component leaks immediately to the extent possible, but not later than one (1) hour after detection of leaks in order to stop or reduce leakage to the atmosphere. [District Rule 2201]

55. If the leak has been minimized but the leak still exceeds the applicable leak standards of this DOC, an operator shall repair or replace the leaking component, vent the leaking component to a closed vent system, or remove the leaking component from operation as soon as practicable but not later than the time period specified in Rule 4455 Table 3. For each calendar quarter, the operator may be allowed to extend the repair period as specified in Rule 4455 Table 3, for a total number of leaking components, not to exceed 0.05 percent of the number of components inspected, by type, rounded upward to the nearest integer where required. [District Rule 2201]

56. If the leaking component is an essential component or a critical component and which cannot be immediately shut down for repairs, the operator shall minimize the leak within one hour after detection of the leak. If the leak has been minimized, but the leak still exceeds any of the applicable leak standards of the DOC, the essential component or critical component shall be repaired or replaced to eliminate the leak during the next process unit turnaround, but in no case later than one year from the date of the original leak detection, whichever comes earlier. [District Rule 2201]

57. For any component that has incurred five repair actions for major gas leaks or major liquid leaks, or any combination of major gas leaks and major liquid leaks within a continuous 12-month period, the operator shall comply with at least one of the requirements specified in Rule 4455 Sections 5.3.7.1, 5.3.7.2, 5.3.7.3, or 5.3.7.4 by the applicable deadlines specified in Sections 5.3.7.5 and 5.3.7.6. If the original leaking component is replaced with a new like-in-kind component before incurring five repair actions for major leaks within 12-consecutive months, the repair count shall start over for the new component. An entire compressor or pump need not be replaced provided the compressor part(s) or pump part(s) that have incurred five repair actions as described in Section 5.3.7 are brought into compliance with at least one of the requirements of Sections 5.3.7.1 through 5.3.7.6. [District Rule 2201]

58. All records required by this DOC shall be retained for a period of at least 5 years and shall be made available to the District upon request. [District Rules 1070 and 2201]

59. The permittee shall obtain written District approval for the use of any equivalent equipment not specifically approved by this Determination of Compliance. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed

alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

60. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

61. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Determination of Compliance. [District Rule 2201]

62. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

63. The air quality modeled impacts of the proposed alternative equivalent equipment shall not result in any more adverse impacts than the equipment it replaces. [District Rule 2201]

Verification: The following verification requirements apply to applicable conditions for permit unit S-7616-33-0:

The project owner shall provide a summary of: 1) operations throughput and annual emissions estimates (Conditions **AQ-18-15**, **-16**, **-38**, and **-39**); 2) portable analyzer test results (Conditions **AQ-18-20** through **-23**); and 3) non-compliance events and associated corrective maintenance (Condition **AQ-18-58**) in the Annual Compliance Reports (**AQ-SC8**).

The project owner shall submit source test plans to the District for approval and the CPM for review at least 15 days prior to testing. The project owner shall provide the results of the source tests to the District and a summary of the source test results, showing compliance with the emissions limits of Condition **AQ-18-15**, to the CPM within 60 days of testing. (Conditions **AQ-18-24** and **-25**)

The project owner shall provide a summary of the fugitive emissions LDAR program, per Conditions **AQ-18-37** through **-57**, in the Annual Compliance Reports (**AQ-SC8**).

The project owner shall submit the written request for the use of alternate equipment, if necessary, to both the District and CPM for approval in accordance with, and that meets the standards of, Conditions **AQ-18-59** through **-63**.

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-18** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-18-11** through **-63**)

AQ-19 The following conditions cover permit unit S-7616-34-0.

UREA UNIT WITH UREA PASTILLATION SYSTEM: UREA UNIT WITH HIGH-PRESSURE AND LOW-PRESSURE ABSORBERS; PASTILLATION UNIT WITH A DROP FORMER, MOVING BELT, OSCILLATING SCRAPER, AND BUCKET ELEVATOR SERVED BY A DUST COLLECTOR

8. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rules 2201 and 2410]

9. Operation shall include the following dust collectors serving the following operations: urea bucket elevator. [District Rule 2201]

10. All conveyors and crushers shall be fully enclosed and shall vent only to dust collectors. [District Rule 2201]

11. All processing and conveying equipment, storage systems, and transfer and loading systems shall be dust-tight (to prevent visible emissions in excess of 5 percent opacity) and shall vent only to dust collectors. [District Rule 2201]

12. Each dust collector shall be equipped with dust-tight (to prevent visible emissions in excess of 5 percent opacity) provisions to return collected material to process equipment. [District Rule 2201]

13. Each dust collector shall be equipped with operational differential pressure indicators, and during fabric collector operation read in the proper range specified by the manufacturer. [District Rule 2201]

14. The differential pressure across each compartment of the dust collectors shall be checked and the results recorded quarterly. If the differential pressure across each compartment of the dust collectors is not within the proper range specified by the manufacturer, corrective action is required prior to further operation of the equipment. Corrective action means that the cause of the improper pressure differential is corrected before operation of the equipment is resumed. [District Rule 2201]

15. Each dust collector shall automatically activate whenever process equipment served is activated. [District Rule 2201]

16. Material shall not be conveyed or crushed unless ventilation system and dust collectors are operating and functioning properly. [District Rule 2201]

17. Permittee shall maintain daily records of the hours of operation of material processed and records shall be made available for District inspection upon request. [District Rule 2201]

18. Airflow for the following dust collector(s) shall not exceed: urea bucket elevator: 1,500 cfm. [District Rule 2201]

19. Particulate matter emissions from the dust collectors shall not exceed 0.001 grains/dscf in concentration. [District Rule 2201]

20. PM10 emissions shall not exceed any of the following emissions for the following operations: urea bucket elevator: 0.3 lb/day. [District Rule 2201]

21. PM10 emissions shall not exceed any of the following emissions for the following operations: urea bucket elevator: 113 lb/yr. [District Rule 2201]

22. The maximum process rates of material on a weight basis shall not exceed any of the following: urea bucket elevator: 1,720 ton/day. [District Rule 2201]

23. The maximum process rates of material on a weight basis shall not exceed any of the following: urea bucket elevator: 627,800 ton/yr. [District Rule 2201]

24. Dust collector filters shall be completely inspected annually while not in operation for tears, scuffs, abrasives or holes which might interfere with PM collection efficiency and shall be replaced as needed. [District Rule 2201]

25. Visible emissions from the operation shall be checked and record results quarterly. If visible emissions are observed, corrective action is required prior to further loading. Corrective action means that visible emissions are eliminated before next loading event. [District Rule 2201]

26. Records of dust control device maintenance, inspection, and repairs shall be maintained. The records shall include identification of equipment, date of inspection, corrective action taken, and identification of individual performing inspection. [District Rule 2201]

27. Testing for particulate matter concentration for each dust collector shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 12 calendar months of the date the previous performance test was required to be completed thereafter. If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed. [District Rule 1081]

28. Testing for compliance with particulate matter concentration limit shall be conducted using EPA method 5. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin. A minimum of three valid test runs are needed to comprise a PM performance test. [District Rule 1081]

29. Testing for the opacity standards for the operations shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 90 operating days of the date the

previous performance test was required to be completed thereafter. If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed. [District Rule 1081]

30. Source testing to determine opacity shall be conducted using EPA method 9. [District Rule 1081]

31. The permittee shall conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible. [District Rule 1081]

32. Permittee shall conduct testing for compliance with the particulate matter concentration limit and particulate matter emissions limit within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility. [District Rule 1081]

33. Permittee shall provide the District at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. [District Rule 1081]

34. Permittee shall maintain a logbook (written or electronic) with the records specified in this document on-site and make it available upon request. [District Rule 1081]

35. All records required by this DOC shall be retained for a period of at least 5 years and shall be made available to the District, ARB, and USEPA upon request. [District Rules 1070 and 2201]

Verification: The following verification requirements apply to applicable conditions for permit unit S-7616-34-0:

The project owner shall provide a summary of: 1) operations throughput and annual emissions estimates (Conditions **AQ-19-20** through **-23**); and 2) non-compliance events and associated corrective maintenance (Condition **AQ-19-26**) in the Annual Compliance Reports (**AQ-SC8**).

The project owner shall submit source test plans to the District for approval and the CPM for review at least 15 days prior to testing. The project owner shall provide the results of the source tests to the District and a summary of the source test results, showing compliance with the emissions limits of Conditions **AQ-19-19** and **-20**, to the CPM within 60 days of testing. (Condition **AQ-19-27**)

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-19** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-19-8** through **-35**)

AQ-20 The following conditions cover permit unit S-7616-35-0.

NITRIC ACID UNIT FOR THE PRODUCTION OF NITRIC ACID FROM AMMONIA OXIDATION, NITRIC OXIDE OXIDATION, AND ABSORPTION SERVED BY: SELECTIVE CATALYTIC REDUCTION (SCR) TO CONTROL NOX, AND TERTIARY CATALYTIC DECOMPOSITION TO CONTROL N2O

8. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

9. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, 10 percent opacity. [District Rules 2201]

10. The production rate of nitric acid shall not exceed 501 tons of nitric acid in one day. [District Rule 2201]

11. The selective catalytic reduction system shall be operated at all times that nitric acid production is occurring. [District Rule 2201]

12. NOx emissions from the nitric acid unit shall not exceed 100.2 lb-NOx/day. [District Rule 2201]

13. NOx emissions from the nitric acid unit shall not exceed 33,617 lb-NOx per calendar year. [District Rule 2201]

14. The ammonia slip emissions (NH3) shall not exceed either of the following limits: 1.0 lb/hr or 10.0 ppmvd @15 percent O2 (based on a 24 hour rolling average). [District Rule 2201]

15. N2O emission rate shall not exceed 0.54 lb-N2O per ton of HNO3 produced. [District Rule 2410]

16. Source testing to quantify N2O emissions (lb-N2O/ton of HNO3 produced) shall be conducted within 60 days after initial start-up, and once every twelve (12) months thereafter, with equipment in operation at 90 percent or more of the rated capacity when the analysis is conducted. [District Rules 1081, 2201, and 2410]

17. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

18. Sampling facilities for source testing shall be provided in accordance with the provisions of Rule 1081 (Source Sampling). [District Rule 1081]

19. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

20. The nitric acid unit shall not discharge into the atmosphere any gases which contained NOx, expressed as NO2, in exceed of 0.20 lb-NOx per ton of nitric acid produced (24-hour rolling average, expressed as 100 percent nitric acid). [District Rule 2201 and 40 CFR 60 Subpart Ga]

21. The nitric acid plant shall comply with the requirements of 40 CFR Part 60, Subpart Ga. [40 CFR 60 Subpart Ga]

22. The permittee shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) for measuring and recording the concentration of NOx emissions in accordance with the provisions of Section 60.13 and Performance Specification 2 of Appendix B and Procedure 1 of Appendix F of part 60. [District Rules 2201, 1080, and 40 CFR 60 Subpart Ga]

23. The permittee shall install, calibrate, maintain, and operate a stack gas flow rate monitoring system. [40 CFR 60 Subpart Ga]

24. The permittee shall determine hourly NOx emissions rate and calculate emissions in units of the applicable emissions limit (lb/ton of 100 percent acid produced). [40 CFR 60 Subpart Ga]

25. The CEMS shall be in continuous operation during all operating periods including unit startup and shutdown, and malfunction. [District Rule 1080 and 40 CFR 60 Subpart Ga]

26. The permittee must use cylinder gas audits to fulfill the quarterly auditing requirement. [40 CFR 60 Subpart Ga]

27. For the NOx concentration CEMS, the permittee must use a span value, as defined in Performance Specification 2, Section 3.11, of Appendix B of this part, of 500 ppmv (as NO2). If the NOx concentrations emitted is higher than 600 ppmv (e.g., during startup or shutdown periods), the permittee must apply a second CEMS or dual range CEMS and a second span value equal to 125 percent of the maximum estimated NOx emission concentration to apply to the second CEMS or to the higher of the dual analyzer ranges during such periods. [40 CFR 60 Subpart Ga]

28. The permittee shall perform a relative accuracy test audit (RATA) for the NOx CEMS as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080 and 40 CFR 60 Subpart Ga]

29. The permittee must operate and certify the continuous emissions rate monitoring system (CERMS) in accordance with the provisions of §60.13 and Performance Specification 6 of Appendix B of part 60 and the specifications of Section 60.73a (Subpart Ga). [District Rule 1080 and 40 CFR 60 Subpart Ga]

30. The permittee must conduct an initial performance test to demonstrate compliance with the NOx emissions limit under §60.72a(a) beginning in the calendar month following initial certification of the NOx and flow rate monitoring CEMS. The initial performance test consists of collection of hourly NOx average concentration, mass flow rate recorded with the certified NOx concentration and flow rate CEMS and the corresponding acid generation (tons) data for all of the hours of operation for the first 30 days beginning on the first day of the first month following completion of the CEMS installation and certification as described above. The permittee must assure that the CERMS meets all of the data quality assurance requirements as per §60.13 and Appendix F, Procedure 1, of this part and you must use the data from the continuous emissions rate monitoring system (CERMS) for this compliance determination. [District Rule 1080 and 40 CFR 60 Subpart Ga]

31. The permittee shall calculate the 24-hour day rolling arithmetic average emission rate in units of the applicable emissions standard (lb-NOx/ton 100 percent acid produced) at the end of each operating day using all the quality assured hourly average CEMS data for the previous 24 operating hours according to the procedures specified in Section 60.75a. [District Rule 2201 and 40 CFR 60 Subpart Ga]

32. The permittee shall maintain records of the following information for each operating day period: (1) hours of operation; (2) production rate of nitric acid, expressed as 100 percent nitric acid; (3) 24-hour average NOx emissions rate values. [District Rule 2201 and 40 CFR Subpart Ga]

33. The permittee shall maintain records of the following time periods: (1) times when the equipment is not in compliance with the emissions standards; (2) times when the pollutant concentration exceeded full span of the NOx monitoring equipment; (3) times when the volumetric flow rate exceeded the high value of the volumetric flow rate monitoring equipment. [40 CFR 60 Subpart Ga]

34. The permittee shall maintain records of any modifications to CEMS which could affect the ability of the CEMS to comply with applicable performance specifications. For each malfunction, the permittee shall maintain records of the following information: (1) records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment; (2) records of actions taken during periods of malfunction to minimize emissions in accordance with section 60.11(d), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. [District Rule 1080 and 40 CFR 60 Subpart Ga]

35. The permittee shall submit performance test data from the initial and subsequent performance tests and from performance evaluations of the continuous monitors to the Administrator at the appropriate address as shown in 40 CFR 60.4. The permittee shall report to the Administrator for each 30 operating day period where the nitric acid plant was not in compliance with the emissions standard: (1) Time period; (2) NOx emission rates (lb/ton of acid produced); (3) Reasons for

noncompliance with the emissions standard; and (4) Description of corrective actions taken. The permittee shall also report the following whenever they occur: (1) Times when the pollutant concentration exceeded full span of the NOx pollutant monitoring equipment; and (2) Times when the volumetric flow rate exceeded the high value of the volumetric flow rate monitoring equipment. [District Rule 1080 and 40 CFR 60 Subpart Ga]

36. The permittee shall report any modifications to CERMS which could affect the ability of the CERMS to comply with applicable performance specifications. [40 CFR 60 Subpart Ga]

37. Within 60 days of completion of the relative accuracy test audit (RATA) required by this subpart, the permittee must submit the data from that audit to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/SSL/cdx/EPA_Home.asp) in the format specified in 40 CFR 60 Subpart Ga, Section 60.77a. [40 CFR 60 Subpart Ga]

38. If a malfunction occurred during the reporting period, the permittee must submit a report that contains the following: (1) The number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded; (2) A description of actions taken by an owner or operator during a malfunction of an affected facility to minimize emissions in accordance with §60.11(d), including actions taken to correct a malfunction. [40 CFR 60 Subpart Ga]

39. Source testing to measure the NOx and NH3 emission rates (lb/hr and ppmvd @ 15 percent O2) and PM10 emission rate (lb/hr) shall be conducted within 60 days after the conclusion of the commissioning period and at least once every twelve months thereafter. [District Rules 1081]

40. The following test methods shall be used: NOx - EPA Method 7E or 20, PM10 - EPA Method 5/202 (front half and back half), CO - EPA Method 10 or 10B, O2 - EPA Method 3, 3A, or 20, VOC - EPA Method 18 or 25, and ammonia - EPA Method 206. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this DOC. The request to utilize EPA approved alternative source testing methods must be submitted in writing and written approval received from the District prior to the submission of the source test plan. [District Rules 1081]

41. NH3 emissions for source test purposes shall be determined using BAAQMD method ST-1B. [District Rule 1081]

42. All records required by this DOC shall be retained for a period of at least 5 years and shall be made available to the District, ARB, and USEPA upon request. [District Rules 1070 and 2201]

Verification: The following verification requirements apply to applicable conditions for permit unit S-7616-35-0:

The project owner shall provide a summary of: 1) operations throughput and annual emissions estimates (Condition **AQ-20-10** and **-13**); and 2) non-compliance events and associated corrective maintenance (Condition **AQ-20-33**) in the Annual Compliance Reports.

The project owner shall provide the results and field data collected during the air pollutant source tests conducted per the requirements of these conditions shall be submitted to the District and a summary of the source test results, showing compliance with the emissions limits of Conditions **AQ-20-12** through **-15**, and **-20**, shall be submitted to the CPM within 60 days of testing. (Conditions **AQ-20-16** through **-19** and **-39** through **-41**).

The project owner shall provide a summary of the CEMS and CERMS data collected in compliance with **AQ-20** Conditions, showing compliance with the emissions limits of Conditions **AQ-20-12**, **-13**, **-15**, and **-20**, shall be submitted to the CPM in the Annual Compliance Reports (**AQ-SC8**). (Conditions **AQ-20-22** and **-29**).

The project owner shall provide any other CEMS and CERMS data (design, performance tests, RATA tests) collected to comply with **AQ-20** conditions in the Quarterly or Annual Compliance Reports (**AQ-SC8**) upon CPM request.

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-20** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-20-8** through **-42**)

AQ-21 The following conditions cover permit unit S-7616-36-0.

AMMONIUM NITRATE UNIT THAT PRODUCES AMMONIUM NITRATE, CONSISTING OF: NEUTRALIZER WITH INTEGRAL SCRUBBER TO CONTROL AMMONIA; PROCESS CONDENSATE TANK WITH VENT SCRUBBER TO CONTROL PARTICULATE MATTER EMISSIONS; AMMONIUM NITRATE COOLER, AND PROCESS PUMP(S)

8. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

9. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20 percent opacity. [District Rule 4101]

10. The permittee shall calibrate, maintain and operate the wet scrubber according the manufacturer's specifications and recommendations. The permittee shall keep records on-site for a period of five years of the calibration and maintenance activities. [District Rule 2201]

11. PM10 emissions from scrubber vent shall not exceed 0.20 lb-PM10/hr. [District Rule 2201]

12. PM10 emission from scrubber vent shall not exceed 0.0075 lb-PM10 per ton of ammonium nitrate produced. [District Rule 2201]

13. Production of ammonium nitrate shall not exceed 636 tons per day nor 212,000 tons during any consecutive 12-month period. [District Rule 2201]

14. Operation of the ammonium nitrate unit shall not exceed 8,000 hours per calendar year. [District Rule 2201]

15. The permittee shall keep records of daily ammonium nitrate production. These records shall contain each month's total and a rolling total for the previous 12 months. [District Rule 2201]

16. Source testing to quantify PM10 emissions (lb-PM10/hr and lb-PM10/ton of ammonium nitrate produced) from scrubber vent shall be conducted within 60 days after initial start-up, and once every twelve (12) months thereafter, with equipment in operation at 90 percent or more of the rated capacity when the analysis is conducted. [District Rules 1081 and 2201]

17. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

18. The following test methods shall be used PM10: EPA method 5 (front half and back half). Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 2201]

19. Sampling facilities for source testing shall be provided in accordance with the provisions of Rule 1081 (Source Sampling). [District Rule 1081]

20. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

21. All records required by this DOC shall be retained for a period of at least 5 years and shall be made available to the District, ARB, and USEPA upon request. [District Rules 1070 and 2201]

Verification: The following verification requirements apply to applicable conditions for permit unit S-7616-36-0:

The project owner shall provide a summary of: 1) operations throughput and annual emissions estimates (Conditions **AQ-21-13** through **-14**); and 2) non-compliance events and associated corrective maintenance (Condition **AQ-21-10**) in the Annual Compliance Reports (**AQ-SC8**).

The project owner shall submit source test plans in compliance with Condition **AQ-21-17** to the District for approval and the CPM for review at least 15 days prior to testing. The project owner shall provide the results of the source tests to the District and a summary of the source test results, showing compliance with the emissions limits of Conditions **AQ-21-11** and **-12**, to the CPM within 60 days of testing. (Condition **AQ-21-16)**

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-21** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-21-8** through **-21**).

AQ-22 The following conditions cover permit unit S-7616-37-0.

UREA STORAGE AND HANDLING OPERATION CONSISTING OF FOUR 20,000-TON STORAGE CAPACITY ENCLOSED UREA STORAGE DOMES EACH WITH ONE UREA TRANSFER TOWER, WITH EACH TRANSFER TOWER SERVED BY ONE DUST COLLECTOR; ENCLOSED UREA RECLAIM BUILDING WITH RECLAIM HOPPERS AND GRIZZLIES; ENCLOSED, TUBULAR RECLAIM CONVEYOR (THAT TRANSFERS MATERIAL TO UREA TRANSFER TOWER #5); UREA TRANSFER TOWER #5 SERVED BY DUST COLLECTOR; ENCLOSED, TUBULAR LOADOUT FEED CONVEYOR (THAT TRANSFERS MATERIAL TO LOADOUT BUILDING); UREA LOADOUT BUILDING SERVED BY BAGHOUSE DUST COLLECTOR, WITH RAIL LOADOUT CONVEYOR, ONE TRUCK AND ONE TRAIN LOADOUT WEIGH SYSTEM, ONE TRUCK AND ONE TRAIN LOADING SPOUT AND VENT SYSTEM

8. Operation shall include the following dust collectors serving the following operations: urea bucket elevator to conveyor, five urea transfer towers, urea loading building vent. [District Rule 2201]

9. All conveyors shall be fully enclosed and shall vent only to dust collectors. [District Rule 2201]

10. All transfer towers, conveyors, urea domes, and urea handling buildings shall be dust-tight (to prevent visible emissions in excess of 5 percent opacity) and shall vent only to dust collectors. [District Rule 2201]

11. Each dust collector shall be equipped with dust-tight (to prevent visible emissions in excess of 5 percent opacity) provisions to return collected material to process equipment. [District Rule 2201]

12. Each dust collector shall be equipped with operational differential pressure indicators, and during fabric collector operation read in the proper range specified by the manufacturer. [District Rule 2201]

13. The differential pressure across each compartment of the dust collectors shall be checked and the results recorded quarterly. If the differential pressure across each compartment of the dust collectors is not within the proper range specified by the manufacturer, corrective action is required prior to further operation of the equipment. Corrective action means that the cause of the improper pressure

differential is corrected before operation of the equipment is resumed. [District Rule 2201]

14. Each dust collector shall automatically activate whenever process equipment served is activated. [District Rule 2201]

15. Material shall not be conveyed or crushed unless ventilation system and dust collectors are operating and functioning properly. [District Rule 2201]

16. Permittee shall maintain daily records of the hours of operation of material unloading at the enclosed truck receiving hoppers and records shall be made available for District inspection upon request. [District Rule 2201]

17. Airflow for the following dust collector(s) shall not exceed: urea transfer tower 1: 1,500 cfm; urea transfer tower 2: 1,500 cfm; urea transfer tower 3: 1,500 cfm; urea transfer tower 4: 1,500 cfm; urea transfer tower 5: 1,500 cfm; urea loading building: 20,000 cfm. [District Rule 2201]

18. Particulate matter emissions from the dust collectors shall not exceed 0.001 grains/dscf in concentration. [District Rule 2201]

19. PM10 emissions shall not exceed any of the following emissions for the following operations: urea transfer tower 1: 0.3 lb/day; urea transfer tower 2: 0.3 lb/day; urea transfer tower 3: 0.3 lb/day; urea transfer tower 4: 0.3 lb/day; urea transfer tower 5: 0.3 lb/day; urea loading building: 4.1 lb/day. [District Rule 2201]

20. PM10 emissions shall not exceed any of the following emissions for the following operations: urea transfer tower 1: 113 lb/yr; urea transfer tower 2: 28 lb/yr; urea transfer tower 3: 56 lb/yr; urea transfer tower 4: 28 lb/yr; urea transfer tower 5: 27 lb/yr; urea loading building baghouse: 357 lb/yr. [District Rule 2201]

21. The maximum process rates of material on a weight basis shall not exceed any of the following: urea bucket elevator to conveyor: 1,720 ton/day; urea transfer tower 1: 1,720 ton/day; urea transfer tower 2: 1,720 ton/day; urea transfer tower 3: 1,720 ton/day; urea transfer tower 4: 1,720 ton/day; urea transfer tower 5: 1,720 ton/day; urea loading building: 1,720 ton/day. [District Rule 2201]

22. The maximum process rates of material on a weight basis shall not exceed any of the following: urea transfer tower 1: 627,800 ton/yr; urea transfer tower 2: 156,950 ton/yr; urea transfer tower 3: 313,900 ton/yr; urea transfer tower 4: 156,950 ton/yr; urea transfer tower 5: 627,800 ton/yr; urea loading building baghouse: 627,800 ton/yr. [District Rule 2201]

23. Dust collector filters shall be completely inspected annually while not in operation for tears, scuffs, abrasives or holes which might interfere with PM collection efficiency and shall be replaced as needed. [District Rule 2201]

24. Visible emissions from the operation shall be checked and record results quarterly. If visible emissions are observed, corrective action is required prior to

further loading. Corrective action means that visible emissions are eliminated before next loading event. [District Rule 2201]

25. Records of dust control device maintenance, inspection, and repairs shall be maintained. The records shall include identification of equipment, date of inspection, corrective action taken, and identification of individual performing inspection. [District Rule 2201]

26. Testing for particulate matter concentration for each dust collector shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 12 calendar months of the date the previous performance test was required to be completed thereafter. If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed. [District Rule 1081]

27. Testing for compliance with particulate matter concentration limit shall be conducted using EPA method 5. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin. A minimum of three valid test runs are needed to comprise a PM performance test. [District Rule 1081]

28. Testing for the opacity standards for the operations shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 90 operating days of the date the previous performance test was required to be completed thereafter. If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed. [District Rule 1081]

29. Source testing to determine opacity shall be conducted using EPA method 9. [District Rule 1081]

30. The permittee shall conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible. [District Rule 1081]

31. Permittee shall conduct testing for compliance with the particulate matter concentration limit and particulate matter emissions limit within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility. [District Rule 1081]

32. Permittee shall provide the District at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. [District Rule 1081]

33. Permittee shall maintain a logbook (written or electronic) with the records specified in this document on-site and make it available upon request. [District Rule 1081]

34. All records required by this DOC shall be retained for a period of at least 5 years and shall be made available to the District, ARB, and USEPA upon request. [District Rules 1070 and 2201]

Verification: The following verification requirements apply to applicable conditions for permit unit S-7616-37-0:

The project owner shall provide a summary of: 1) operations throughput and annual emissions estimates (Conditions **AQ-22-19** through **-22**); and 2) non-compliance events and associated corrective maintenance (Condition **AQ-22-25**) in the Annual Compliance Reports (**AQ-SC8**).

The project owner shall submit source test plans to the District for approval and the CPM for review at least 15 days prior to testing. The project owner shall provide the results of the source tests to the District and a summary of the source test results, showing compliance with the emissions limits of Conditions **AQ-22-18** and **-19**, to the CPM within 60 days of testing. (Condition **AQ-22-26**)

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-22** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-22-8** through **-34**)

AQ-23 The following conditions cover permit unit S-7616-38-0.

2,922 BHP CUMMINS MODEL QSK60-G6 INTERIM TIER 4 (OR THE HIGHEST TIER RATING APPLICABLE AT THE TIME OF INSTALLATION, WHICHEVER TIER IS HIGHER) CERTIFIED DIESEL-FIRED EMERGENCY STANDBY IC ENGINE POWERING A 2,000 KW CUMMINS MODEL DQKC ELECTRIC GENERATOR, #1 (OR EQUIVALENT)

8. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

9. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20 percent opacity. [District Rule 4101]

10. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]

11. Only CARB certified diesel fuel containing not more than 0.0015 percent sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

12. This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702, 17 CCR 93115, and 40 CFR 60 Subpart IIII]

13. This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702 and 40 CFR 60 Subpart IIII]

14. An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

15. Emissions from this IC engine shall not exceed any of the following limits: 0.5 g-NOx/bhp-hr, 2.6 g-CO/bhp-hr, or 0.3 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

16. Emissions from this IC engine shall not exceed 0.07 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

17. The engine EPA Tier rating shall be the highest applicable Tier rating at the time of installation. [District Rules 2201 and 2410, and 13 CCR 2423 and 17 CCR 93115]

18. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rules 4702 and 2410, and 17 CCR 93115]

19. The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

20. All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

21. The permittee shall obtain written District approval for the use of any equivalent equipment not specifically approved by this Determination of Compliance. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

22. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

23. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Determination of Compliance. [District Rule 2201]

24. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

25. The air quality modeled impacts of the proposed alternative equivalent equipment shall not result in any more adverse impacts than the equipment it replaces. [District Rule 2201]

Verification: The following verification requirements apply to applicable conditions for permit unit S-7616-38-0:

The project owner shall submit the engine specifications at least 30 days prior to purchasing the engines to the District for review and approval and to the CPM for review demonstrating that the engines meet highest engine tier requirement and meet NSPS and ARB ATCM emission limit requirements at the time of engine purchase and the emission limit requirements of Conditions **AQ-23-8**, **-15**, and **-16**; and the design requirements of Conditions **AQ-23-10** and **-12**. (Condition **AQ-23-17**)

The project owner shall provide a summary of the hours of operation showing compliance with Condition **AQ-23-18** and **-19**, and summary of annual emissions in the Annual Compliance Reports (**AQ-SC8**).

The project owner shall submit the written request for the use of alternate equipment, if necessary, to both the District and CPM for approval in accordance with, and that meet the standards of, Conditions **AQ-23-21** through **-25**.

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-23** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-23-8** through **-25**)

AQ-24 The following conditions cover permit unit S-7616-39-0.

2,922 BHP CUMMINS MODEL QSK60-G6 INTERIM TIER 4 (OR THE HIGHEST TIER RATING APPLICABLE AT THE TIME OF INSTALLATION, WHICHEVER TIER IS HIGHER) CERTIFIED DIESEL-FIRED EMERGENCY STANDBY IC ENGINE POWERING A 2,000 KW CUMMINS MODEL DQKC ELECTRIC GENERATOR, #2 (OR EQUIVALENT)

8. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

9. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20 percent opacity. [District Rule 4101]

10. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]

11. Only CARB certified diesel fuel containing not more than 0.0015 percent sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

12. This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702, 17 CCR 93115, and 40 CFR 60 Subpart IIII]

13. This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702 and 40 CFR 60 Subpart IIII]

14. An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

15. Emissions from this IC engine shall not exceed any of the following limits: 0.5 g-NOx/bhp-hr, 2.6 g-CO/bhp-hr, or 0.3 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

16. Emissions from this IC engine shall not exceed 0.07 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

17. The engine EPA Tier rating shall be the highest applicable Tier rating at the time of installation. [District Rules 2201 and 2410, and 13 CCR 2423 and 17 CCR 93115]

18. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rules 4702 and 2410, and 17 CCR 93115]

19. The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual

operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

20. All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

21. The permittee shall obtain written District approval for the use of any equivalent equipment not specifically approved by this Determination of Compliance. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

22. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

23. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Determination of Compliance. [District Rule 2201]

24. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

25. The air quality modeled impacts of the proposed alternative equivalent equipment shall not result in any more adverse impacts than the equipment it replaces. [District Rule 2201]

Verification: The following verification requirements apply to applicable conditions for permit unit S-7616-39-0:

The project owner shall submit the engine specifications at least 30 days prior to purchasing the engines for review and approval demonstrating that the engines meet highest engine tier requirement and meet NSPS and ARB ATCM emission limit requirements at the time of engine purchase and the emission limit requirements of Conditions **AQ-24-8**, **-15**, and **-16**; and the design requirements of Conditions **AQ-24-10** and **-12**. (Condition **AQ-24-17**).

The project owner shall provide a summary of the hours of operation showing compliance with Condition **AQ-24-18** and **-19**, and summary of annual emissions in the Annual Compliance Reports (**AQ-SC8**).

The project owner shall submit the written request for the use of alternate equipment, if necessary, to both the District and CPM for approval in accordance with, and that meets the standards of, Conditions **AQ-24-21** through **-25**.

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-24** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-24-8** through **-25**)

AQ-25 The following conditions cover permit unit S-7616-40-0.

556 BHP CUMMINS MODEL CFP-15E-F40 INTERIM TIER 4 (OR THE HIGHEST TIER RATING APPLICABLE AT THE TIME OF INSTALLATION, WHICHEVER TIER IS HIGHER) CERTIFIED DIESEL-FIRED EMERGENCY STANDBY IC ENGINE POWERING A FIREWATER PUMP (OR EQUIVALENT)

8. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

9. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20 percent opacity. [District Rule 4101]

10. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]

11. Only CARB certified diesel fuel containing not more than 0.0015 percent sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

12. This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702, 17 CCR 93115, and 40 CFR 60 Subpart IIII]

13. This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702 and 40 CFR 60 Subpart IIII]

14. An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

15. Emissions from this IC engine shall not exceed any of the following limits: 1.5 g-NOx/bhp-hr, 2.6 g-CO/bhp-hr, or 0.14 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

16. Emissions from this IC engine shall not exceed 0.01 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

17. The engine EPA Tier rating shall be the highest applicable Tier rating at the time of installation. [District Rules 2201 and 2410, and 13 CCR 2423 and 17 CCR 93115]

18. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems". Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 100 hours per calendar year. [District Rule 4702 and 2410, and 17 CCR 93115]

19. The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

20. All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

21. The permittee shall obtain written District approval for the use of any equivalent equipment not specifically approved by this Determination of Compliance. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

22. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

23. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Determination of Compliance. [District Rule 2201]

24. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

25. The air quality modeled impacts of the proposed alternative equivalent equipment shall not result in any more adverse impacts than the equipment it replaces. [District Rule 2201]

__**Verification:**__ The following verification requirements apply to applicable conditions for permit unit S-7616-40-0:

The project owner shall submit the engine specifications at least 30 days prior to purchasing the engines for review and approval demonstrating that the engines meet highest engine tier requirement and meet NSPS and ARB ATCM emission limit requirements at the time of engine purchase and the emission limit requirements of Conditions **AQ-25-8**, **-15**, and **-16**; and the design requirements of Conditions **AQ-25-10** and **-12**. (Condition **AQ-25-17**)
The project owner shall provide a summary of the hours of operation showing compliance with Condition **AQ-25-18** and **-19**, and summary of annual emissions in the Annual Compliance Reports (**AQ-SC8**).

The project owner shall submit the written request for the use of alternate equipment, if necessary, to both the District and CPM for approval in accordance with, and that meets the standards of, Conditions **AQ-25-21** through **-25**.

The project owner shall make the site available for inspection of equipment and records kept to show compliance with all **AQ-25** Conditions by representatives of the District, ARB, U.S. EPA, and the Commission upon request. (Conditions **AQ-25-8** through -**25**).

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ACRONYMS

AADT	Annual Average Daily Trip
AAQS	Ambient Air Quality Standard
ACEC	Area of Critical Environmental Concern
AER	Actual Emissions Reductions
AERMOD	ARMS/EPA Regulatory Model
AFC	Application for Certification
AGR	Acid Gas Removal
AIR	Association of Irritated Residents
APCO	Air Pollution Control Officer (SJVAPCD)
AQ	Air Quality
AQCMM	Air Quality Construction Mitigation Manager
AQCMP	Air Quality Construction Mitigation Plan
AQI	Air Quality Index
AQMP	Air Quality Management Plan
AQRVs	Air Quality Related Values
ARB/CARB	California Air Resources Board
ASU	Air Separation Unit
ASTM	ASTM International, formerly known as American Society for Testing and Materials.
ATC	Authority to Construct
ATCM	Air Toxics Control Measure
BAAQMD	Bay Area Air Quality Management District
BACT	Best Available Control Technology
bhp or BHP	Brake Horsepower
bhp-hr	Brake Horsepower Hours
BOP	Balance of Plant
Btu	British Thermal Units
CAA	Clean Air Act
CAAQS	California Ambient Air Quality Standards
CAPCOA	California Air Pollution Controls Officers Association
CCPI	Clean Coal Power Initiative
CCR	California Code of Regulations
CDX	Central Data Exhange (U.S. EPA Online Data Resource)
CEC	California Energy Commission (or Energy Commission)
CEDRI	Compliance and Emissions Data Reporting Interface (part of CDX)
CEM	Continuous Emission Monitor
CEMP	Construction Emissions Mitigation Plan
CEMS	Continuous Emissions Monitoring System
CEQA	California Environmental Quality Act
CERMS	Continuous Emissions Rate Monitoring System
cfm	Cubic Feet per Minute
CFR	Code of Federal Regulations
CH_4	Methane
CO	Carbon Monoxide

CO_2 or CO2	Carbon Dioxide
CO2e/CO2E	Carbon Dioxide Equivalent
Coanda effect	Mixing that occurs when a gas is passed over a carefully profiled curved surface creating high efficiency combustion
COS	Carbonyl Sulfide
CPM	Compliance Project Manager (Energy Commission)
Cr^{6+}	Chromium
CS_2	Carbon Disulfide
CTB	Central Tank Battery
CTG	Combustion Turbine Generator
DEIS	Draft Environmental Impact Statement
DELs	Daily Emission Limitations
DOC	Determination of Compliance
DOE	United States Department Of Energy
DPM	Diesel Particulate Matter
dscf	Dry Standard Cubic Foot
dscm	Dry Standard Cubic Meter
EHOF	Elk Hills Oil Field
EIR	Environmental Impact Reports
EOR	Enhanced Oil Recovery
EPA	United States Environmental Protection Agency, also U.S. EPA
ERC	Emission Reduction Credit
ERIP	Emissions Reduction Incentive Program
FDOC	Final Determination Of Compliance
FEIS	Final Environmental Impact Statement
FLM	Federal Land Manager
FMP	Flare Minimization Plan
FSA	Final Staff Assessment
ft/sec	Feet per Second
GEP	Good Engineering Practice
GHG	Greenhouse Gas
GPM	Gallon Per Minute
gr	Grains (1 gr $\cong$ 0.0648 grams, 7000 gr = 1 pound)
GWh	Gigawatt-hour
H_2S or H2S	Hydrogen Sulfide
HAP or HAPs	Hazardous Air Pollutants
HCl	Hydrogen Chloride
HECA	Hydrogen Energy California Project
Hg	Mercury
HHV	Higher Heating Value
HNO_3	Nitric Acid
hp	Horsepower
hr	Hour
HRA	Health Risk Assessment
HRSG	Heat Recovery Steam Generator
HSC	Health and Safety Code
IC	Internal Combustion

IGCC	Integrated Gasification Combined Cycle
ISO	International Organization for Standardization
km	Kilometer
kW	Kilowatt
LAER	Lowest Achievable Emission Rate
lb or lbs	Pound or Pounds
LDAR	Leak Detection and Repair
LHV	Lower Heating Value
LORS	Law, Ordinances, Regulations, and Standards
LPG	Liquefied Petroleum Gas
LTGC	Low Temperature Gas Cooling
MATS	Mercury And Air Toxics Standards
MCR	Monthly Compliance Report
$\mu g/m^3$	Microgram per cubic meter
mg	Milligram
mg/m^3	Milligram per cubic meter
MHI	Mitsubishi Heavy Industries
MMBtu	Million British Thermal Units
MMBtu/hr	Million British Thermal Units per Hour
MMscfd	Million Standard Cubic Feet Per Day
mol	Mole
MRV	Monitoring, Reporting and Verification
MW	Megawatts (1,000,000 Watts)
MWh	Megawatt-hour
N_2O or N2O	Nitrous Oxide
NAAQS	National Ambient Air Quality Standards
ND	No Data
NEPA	National Environmental Policy Act
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NFPA	National Fire Protection Association
NH_3 or NH3	Ammonia
NMHC	Non-methane Hydrocarbons
NMOC	Non-methane Organic Compounds
NNSR	Nonattainment New Source Review
NO	Nitric Oxide
NO_2 or NO2	Nitrogen Dioxide
NOx	Oxides of Nitrogen *or* Nitrogen Oxides
NRU	Nitrogen Reinjection Unit
NSPS	New Source Performance Standard
NSR	New Source Review
O_2 or O2	Oxygen
O_3	Ozone
OEHI	Occidental of Elk Hills, Inc
PAMS	Photochemical Assessment Monitoring Station
Pb	Lead
PDOC	Preliminary Determination Of Compliance
petcoke	Petroleum Coke

PM	Particulate Matter
PM10	Particulate Matter less than 10 microns in diameter
PM2.5	Particulate Matter less than 2.5 microns in diameter
ppm	Parts Per Million
ppmv	Parts Per Million by Volume
ppmvd	Parts Per Million by Volume, Dry
ppmw	Parts Per Million by Weight
PRD	Pressure Release Device
PS	Performance Specification
PSA	Pressure Swing Absorption
PSA/DEIS	Preliminary Staff Assessment/Draft Environmental Impact Statement
PSD	Prevention of Significant Deterioration
psig	Pounds per Square Inch Gauge
PTO	Permit to Operate
PUC	California Public Utility Commission
PVMRM	Plume Volume Molar Ratio Method
Q/d	Emissions over Distance ratio
RACM	Reasonably Available Control Measure
RACT	Reasonably Available Control Technology
RATA	Relative Accuracy Test Audit
RCF	Reinjection Compression Facility
RICE	Reciprocating Internal Combustion Emissions
Ringlemann	A standard measure of opacity (opaqueness of plumes)
SB	Senate Bill
scf	Standard Cubic Feet
SCR	Selective Catalytic Reduction
SF6	Sulfur Hexafluoride
SILs	Significant Impact Levels
SIP	State Implementation Plan
SJVAB	San Joaquin Valley Air Basin
SJVAPCD	San Joaquin Valley Air Pollution Control District (also District)
SO_2 or SO2	Sulfur Dioxide
SO_4	Sulfates
SOCMI	Synthetic Organic Chemical Manufacturing Industry
SOx	Oxides of Sulfur
SRU	Sulfur Recovery Unit
SSU	Sour Shift Unit
std	Standard
STG	Steam Turbine Generator
SWPPP	Storm Water Pollution Prevention Plan
SWS	Sour Water Stripper
syngas	Synthetic Gas
T-BACT	BACT for toxic emission control
TACs	Toxic Air Pollutants
TCMs	Transportation Control Measures
TDS	Total Dissolved Solids
TEG	Triethylene Glycol

TFV	Threshold Friction Velocity
TGU	Tail Gas Unit
TPAs	Transportation Planning Agencies
TPY/tpy	Tons per Year
UAN	Urea Ammonium Nitrate
U.S. EPA	United States Environmental Protection Agency
VDE	Visible Dust Emissions
VERA	Voluntary Emissions Reduction Agreement
Vmax	Maximum Velocity
VOC	Volatile Organic Compounds
WC	Weather Channel
yr	Year

Appendix Air-1

General Conformity Evaluation and Determination

NATIONAL ENERGY TECHNOLOGY LABORATORY
Albany, OR • Morgantown, WV • Pittsburgh, PA
U.S. DEPARTMENT OF ENERGY

April 25, 2013

Robert Worl
Siting Project Manager
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814-5512

Dear Mr. Worl:

As we have discussed, the United States Department of Energy (DOE) is considering providing financial assistance for the construction and operation of the Hydrogen Energy California Project (HECA). DOE's proposed action is subject to the Clean Air Act's General Conformity Rule (GCR) set forth in section 176(c) of the Act and 40 CFR Part 93.

DOE's practice is to coordinate its compliance with the GCR with its preparation of the analyses of potential impacts required by the National Environmental Policy Act (NEPA), in particular the GCR's requirements for public participation in 40 CFR § 93.156. Accordingly, DOE requests that the staff of the California Energy Commission (CEC) incorporate the attached *General Conformity Evaluation* into appropriate section of the Preliminary Staff Assessment/Draft Environmental Impact Statement (PSA/DEIS). In addition, DOE requests that CEC staff incorporate into the PSA/DEIS the text DOE provided earlier regarding its adoption of this evaluation.

DOE intends to publish a Notice of Availability in the Federal Register announcing that the PSA/DEIS is available for public review and comment. This notice will state that the draft *General Conformity Evaluation* is included in the PSA/DEIS and invite the public to comment on the evaluation as well as the other information presented in the PSA/DEIS. DOE will also send copies of its draft evaluation to federal, tribal, state, and local organizations as required by 40 CFR § 93.155.

The applicant, HECA LLC, has negotiated enforceable commitments with the San Joaquin Valley Air Pollution Control District (SJVAPCD) that call for HECA to provide funds to the District's Emission Reduction Incentive Program (ERIP), which the SJVAPCD will disburse as grants to emission reduction projects. The SJVAPCD will administer the projects and verify the emission reductions. The SJVAPCD will fund projects within the San Joaquin Valley Air Basin (SJVAB) that produce real, quantifiable and enforceable emission reductions that will occur contemporaneously with the emissions from the project that are subject to the GCR. The District intends to fund enough projects to more than offset the HECA project's anticipated GCR emissions (that is, the SJVAPCD is requiring the applicant to provide funding for a surplus of emission reductions in the SJVAB). Through this mechanism, the District will ensure that construction and operational emissions of nitrogen oxide and volatile organic compounds from the project that exceed the GCR thresholds will be more than offset by the emission reductions achieved by the District's ERIP. On the basis of these agreements and the analysis in the attached

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General Conformity Evaluation, DOE believes that the project will conform to the applicable state implementation plans and that DOE's proposed federal action of providing financial assistance to the applicant would comply with the requirements of the GCR. DOE consulted with the applicant and the SJVAPCD regarding the *General Conformity Evaluation* and the emission reduction agreements.

If you should have any questions, please contact Cliff Whyte, Environmental Compliance Division Director, at (304)285-2098 at your convenience.

Sincerely,

R. Paul Detwiler
Chief Counsel

Attachment

HYDROGEN ENERGY CALIFORNIA
KERN COUNTY, CALIFORNIA

DRAFT GENERAL CONFORMITY EVALUATION

April 2013

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List of Acronyms

AGR	Acid Gas Removal
BVWSD	Buena Vista Water Storage
CAA	Clean Air Act
CARB	California Air Resource Board
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CTG	Combustion Turbine Generator
DMV	Department of Motor Vehicles
EKAPCD	Eastern Kern Air Pollution Control District
EOR	Enhanced Oil Recovery
ERCs	Emission Reduction Credit
FHWA	Federal Highway Administration
FR	Federal Register
FTA	Federal Transit Administration
GAC	Granular-Activated Carbon
GCD	General Conformity Determination
GHG	Greenhouse Gases
HECA LLC	Hydrogen Energy California LLC
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
IGCC	Integrated Gasification Combined Cycle
LLC	Limited Liability Company
LTGC	Low Temperature Gas Cooling
MDAQMD	Mojave Desert Air Quality Management District
MHI	Mitsubishi Heavy Industries Ltd.
MPO	Metropolitan Planning Organization
MW	Megawatts
N/A	Not Applicable
NAAQS	National Ambient Air Quality Standard
NEPA	National Environmental Policy Act
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxides
NSR	New Source Review
O_3	Ozone
Petcoke	Petroleum Coke
PG&E	Pacific Gas and Electric Company
PM_{10}	Particulate Matter Less Than 10 Microns in Diameter
$PM_{2.5}$	Particulate Matter Less Than 2.5 Microns in Diameter
PSA	Pressure Swing Adsorption
SCAQMD	South Coast Air Quality Management District
SIP	State Implementation Plan
SJVAB	San Joaquin Valley Air Basin
SJVAPCD	San Joaquin Valley Air Pollution Control District
SJVRR	San Joaquin Valley Railroad
SMAQMD	Sacramento Metropolitan Air Quality Management District

SO_2	Sulfur Dioxide
SRU	Sulfur Recovery Unit
Syngas	Synthesis Gas
Tpy	Tons Per Year
U.S. DOE	United State Department of Energy
U.S. DOT	United State Department of Transportation
U.S. EPA	United State Environmental Protection Agency
UAN	Urea Ammonium Nitrate
VOC	Volatile Organic Compound
WKWD	West Kern Water District

Hydrogen Energy California LLC (HECA LLC) is proposing an Integrated Gasification Combined Cycle (IGCC) polygeneration project located approximately 7 miles west of the outermost edge of the City of Bakersfield, and 1.5 miles northwest of the unincorporated community of Tupman, in western Kern County, California, as seen in Figure 1 (the "Project" or "HECA Project"). The Project will gasify a fuel blend of 75 percent coal and 25 percent petroleum coke (petcoke) to produce synthesis gas (syngas). Syngas produced via gasification will be purified to hydrogen-rich fuel, and used to generate a nominal 300 megawatts (MW) of low-carbon baseload electricity in a Combined Cycle Power Block, low-carbon nitrogen-based fertilizer in an integrated Manufacturing Complex, and carbon dioxide (CO_2) for use in enhanced oil recovery (EOR).

Section 176(c)(1) of the Clean Air Act (CAA) requires any entity of the federal government that engages in, supports, or in any way provides financial support for, licenses, or permits, or approves any activity, to demonstrate that the action conforms to the applicable State Implementation Plan (SIP) for achieving and maintaining the National Ambient Air Quality Standards (NAAQS) for criteria pollutants before the action is otherwise approved (General Conformity Rule). The HECA Project will receive financial support from the United States Department of Energy (U.S. DOE), and will be subject to the National Environmental Policy Act (NEPA) environmental review process by the U.S. DOE. Therefore, the HECA Project is subject to the requirements of the Federal Clean Air Act General Conformity Rule for all nonattainment and maintenance areas affected by the direct and indirect emissions from the Project.

An evaluation of General Conformity was performed for the HECA Project for all the affected nonattainment and maintenance areas in the states of California, Arizona, and New Mexico. Criteria pollutant emissions generated in each Project-affected area from activities associated with Project construction and operation were estimated and compared to the General Conformity *de minimis* thresholds to assess whether a General Conformity Determination (GCD) is required.

The estimated emissions indicate that the total direct and indirect construction and operational emissions of carbon monoxide (CO), particulate matter less than 10 microns in diameter (PM_{10}), particulate matter less than 2.5 microns in diameter ($PM_{2.5}$), and sulfur dioxide (SO_2) are below the applicable General Conformity thresholds for all years of construction and operation in all nonattainment and maintenance areas. Construction and operational emissions of nitrogen oxides (NO_x) exceed the General Conformity threshold each year of construction and operation in the San Joaquin Valley Air Basin (SJVAB). Construction emissions of volatile organic compounds (VOCs) exceed the General Conformity threshold in years 2014 and 2015 in the SJVAB. This requires a General Conformity Evaluation and Determination in the SJVAB for NO_x for construction and operation; and for VOC during construction.

HECA has entered into an enforceable commitment with the San Joaquin Valley Air Pollution Control District (SJVAPCD) to provide funds to the SJVAPCD's Emission Reduction Incentive Program (ERIP), which would be disbursed in the form of grants for emission reduction projects. The SJVAPCD serves as both the administrator of the projects and the verifier of the emission reductions. The SJVAPCD will fund projects within the SJVAB that will produce real, quantifiable, enforceable, and surplus emission reductions, contemporaneously with Project emission increases. Through this mechanism, construction and operational emissions of NO_x and VOC from the Project which exceed the General Conformity thresholds will be fully offset and the federal action will conform to the SIP pursuant to Title 40, Code of Federal Regulations, Part 93, Subpart B, Section 93.158(a)(2) and/or Section 93.158(a)(5)(iii).

The HECA IGCC polygeneration project is located near the community of Tupman, as shown in Figure 1. The Project will gasify a fuel blend of 75 percent coal and 25 percent petroleum coke (petcoke) to produce synthesis gas (syngas). Syngas produced via gasification will be purified to hydrogen-rich fuel, and used to generate a nominal 300 megawatts (MW) of low-carbon baseload electricity in a Combined Cycle Power Block, low-carbon nitrogen-based fertilizer in an integrated Manufacturing Complex, and carbon dioxide (CO_2) for use in enhanced oil recovery (EOR). The HECA Project Site comprises a 453-acre parcel of land on which the HECA IGCC electrical generation facility, low-carbon nitrogen-based fertilizer Manufacturing Complex, and associated equipment and processes (excluding off-site portions of linear facilities), will be located. HECA has an agreement to purchase the HECA Project Site, as well as an additional 653 acres adjacent to the HECA Project Site, herein referred to as the Controlled Area. HECA will have control over public access and future land use on this property. In addition, the HECA Project will include the following linear facilities, which extend off the Project Site.

- Electrical transmission line. An approximately 2-mile-long electrical transmission line will interconnect the Project to a future Pacific Gas and Electric Company (PG&E) switching station east of the Project Site.
- Natural gas supply pipeline. An approximately 13-mile-long natural gas interconnection will be made with PG&E natural gas pipelines north of the Project Site.
- Water supply pipelines and wells. An approximately 15-mile-long process water supply line and up to five new groundwater wells will be installed by the Buena Vista Water Storage District (BVWSD) to supply brackish groundwater from northwest of the Project Site. An approximately 1-mile-long water supply linear from the West Kern Water District (WKWD) east of the Project Site will provide potable water.

A fleet of trucks and trains will be used for the transportation of feedstock and product to/from the Project Site on a regular basis during commercial operation. HECA is considering two alternatives for transporting the feedstock coal to the Project Site.

- Alternative 1, rail transportation. An approximately 5-mile-long new industrial railroad spur will connect the Project Site to the existing San Joaquin Valley Railroad (SJVRR) Buttonwillow railroad line, north of the Project Site. This railroad spur will also be used to transport some HECA products to market.
- Alternative 2, truck transportation. An approximately 27-mile-long truck transport route via existing roads from an existing coal transloading facility northeast of the Project Site.

Based on the transportation alternatives, the Project impact area will include the states of California, Arizona, and New Mexico for the General Conformity Determination (GCD) purposes. However, only the areas that are currently designated by the United States Environmental Protection Agency (U.S. EPA) as nonattainment or maintenance areas are required to be analyzed.

The construction of HECA is anticipated to start in 2013 and to be completed in 2017. The anticipated Project commercial operation start date is September 2017. During calendar year 2017, both construction activities and operational activities will occur.

Section 176(c)(1) of the Clean Air Act (CAA) requires any entity of the federal government that engages in, supports, or in any way provides financial support for, licenses, or permits, or approves any activity, to demonstrate that the action conforms to the applicable State Implementation Plan (SIP) for achieving and maintaining the National Ambient Air Quality Standards (NAAQS) for criteria pollutants before the action is otherwise approved. The General Conformity requirement is implemented pursuant to regulations set forth at Title 40, Code of Federal Regulations, Part 93 (General Conformity Rule).

A SIP is a state's compilation of its air quality control plans and rules that will be implemented to achieve compliance with the NAAQS. Criteria pollutants are six major air pollutants for which the U.S. EPA has established NAAQS. These pollutants are ozone (O_3), particulate matter (particulate matter less than 10 microns in diameter [PM_{10}] and particulate matter less than 2.5 microns in diameter [$PM_{2.5}$]), carbon monoxide (CO), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), and lead. This analysis examines emissions from all criteria pollutants and their precursors except lead and ammonia (a $PM_{2.5}$ precursor), because these are not emitted from the non-exempt General Conformity sources (i.e., transportation sources).

Section 176(c)(1) also assigns primary oversight responsibility for conformity assurance to the agencies themselves, not to the U.S. EPA or the states. Specifically, for there to be conformity, a federal action must not contribute to new violations of standards for ambient air quality, increase the frequency or severity of existing violations, or delay timely attainment of standards in the area of concern.

Due to the financial support from the United States Department of Energy (U.S. DOE), the General Conformity Rule is applicable in the San Joaquin Valley Air Basin (SJVAB) and all other nonattainment and maintenance areas affected by the direct and indirect emissions from the Project. HECA has estimated annual Project emissions of nonattainment and maintenance pollutants and their precursors to determine if emissions of these pollutants are above the General Conformity *de minimis* thresholds, and thus subject to the General Conformity Rule, and to determine whether the proposed action conforms to the SIP. This General Conformity evaluation for HECA was prepared to confirm that the proposed action would conform to the SIP.

The General Conformity Rule establishes certain procedural requirements that must be followed when preparing a General Conformity evaluation. This section addresses the regulatory background, requirements, and processes of the General Conformity Rule.

2.1 GENERAL CONFORMITY REGULATORY BACKGROUND

The U.S. EPA promulgated the General Conformity Rule on November 30, 1993, in Volume 58 of the Federal Register (FR) Page 63214 (58 FR 63214) to implement the conformity provision of Title I, Section 176(c) of the federal CAA (42 U.S.C. § 7506(c)). Section 176(c)(1) requires that the federal government not engage, support, or provide financial assistance for, permit or license, or approve any activity that fails to conform to an approved SIP.

The General Conformity Rule is codified in 40 Code of Federal Regulations (CFR) Part 93 (40 CFR 93), Subpart B, "*Determining Conformity of General Federal Actions to State or Federal Implementation Plans*". The General Conformity Rule applies to all federal actions, except programs and projects that require funds or approval from the U.S. Department of Transportation (U.S. DOT), the Federal Highway Administration (FHWA), the Federal Transit Administration (FTA), or the Metropolitan Planning Organization (MPO). In lieu of a General Conformity analysis, these latter types of programs and projects must comply with the Transportation Conformity Rule promulgated by U.S. DOT on November 24, 1993 (58 FR 62197).

The federal General Conformity Rule is often incorporated into state and local regulations. For instance, the San Joaquin Valley Air Pollution Control District (SJVAPCD) has adopted the federal General Conformity regulations in its Rule 9110, "*General Conformity.*"

2.2 GENERAL CONFORMITY REQUIREMENTS

As defined in the CAA, Title I, Section 176(c)(1), conformity means to uphold air quality goals through reduction or elimination of NAAQS violations. Accordingly, a proposed action or activity achieves conformity if the associated pollutant emissions would not:

- Cause or contribute to new violations of any NAAQS in any area;
- Increase the frequency or severity of any existing violation of any NAAQS; or
- Delay timely attainment of any NAAQS or interim emission reductions.

The General Conformity Rule establishes conformity in coordination with and as part of the NEPA environmental review process. The General Conformity Rule affects air pollutant emissions associated with actions that are federally funded, licensed, permitted, or approved; and ensures emissions do not contribute to air quality degradation, or prevent the achievement of state and federal air quality goals. In short, General Conformity, if applicable, refers to the process to evaluate plans, programs, and projects to determine and demonstrate that they satisfy the requirements of the CAA and applicable SIP. A positive GCD of a project can be shown through state emission budgets in the SIP, emission offsets, or air quality modeling.

In the SJVAPCD jurisdiction, U.S. EPA approved the 2004 Extreme Ozone Attainment Demonstration Plan for 1-hour ozone on March 8, 2010. However, this SIP is based on the revoked federal 1-hour ozone standard and does not have any projected emissions for milestone years after 2010, as attainment was expected to be achieved by then. On August 30, 2012, U.S. EPA proposed to withdraw its approval of the 2004 ozone plan. This action will require SJVAPCD to develop new plans for attainment of the 1-hour ozone air quality standard. SJVAPCD is preparing this new 1-hour ozone plan currently and expects to finish and submit this to California Air Resources Board (CARB) and U.S. EPA in 2013. On the other hand, the SJVAPCD's Governing Board adopted the 2007 8-hour Ozone Plan and its amendments in 2007 and 2008, and 2011. This SIP was approved by CARB and U.S. EPA on March 1, 2012. Therefore, the SJVAPCD's 2007 8-hour Ozone Plan is the current applicable SIP to be used for the HECA Project.

SJVAPCD has adopted the 2008 $PM_{2.5}$ Plan, although this plan has not yet been approved by U.S. EPA. Therefore, it was determined that the current applicable SIPs to be used in the SJVAPCD jurisdiction area for this General Conformity analysis are the 2007 8-hour ozone plan, the 2008 $PM_{2.5}$ plan, the U.S. EPA-approved 2007 PM_{10} Maintenance Plan and Request for Re-designation, and the U.S. EPA-approved 1996 Carbon Monoxide Re-designation Request and Maintenance Plan for Ten Federal Planning Areas.

2.3 GENERAL CONFORMITY PROCESSES

This General Conformity analysis was prepared based on guidance from two documents: the U.S. EPA General Conformity Guidance (40 CFR 93, Subpart B) and the U.S. DOE CAA General Conformity Requirements and the NEPA Process (DOE, 2000).

The process to evaluate General Conformity for a proposed federal action involves two major phases or processes: the General Conformity Applicability Review process, and the GCD process. Applicability review process is required for any action that is federally funded, licensed, permitted, or approved, where the total direct and indirect emissions for criteria pollutants and precursors in a nonattainment or maintenance area exceed the General Conformity *de minimis* rates specified in 40 CFR 93.153(b)(1) and (2). If emissions exceed these rates, then a GCD is required.

Based on the definitions from 40 CFR 93.153 and U.S. EPA General Conformity Guidance, direct emissions are caused by the action itself, such as the emissions from the construction of a facility. Indirect emissions are also caused by the action, but are removed from the action in either time or space. For example, emissions from employees commuting to a facility are indirect emissions. Both direct and indirect emissions have to be reasonably foreseeable, meaning that the emissions can be estimated based on acceptable techniques using reasonable assumptions about the type and quantity of equipment used.

The General Conformity requirements and the NEPA Process Guide from the U.S. DOE provide four steps for the General Conformity Applicability process to determine whether the next phase of General Conformity evaluation requirements apply to a federal action, and therefore, that a GCD may be needed. The four steps are:

- Step 1 – Determine whether criteria pollutants and their precursors would be emitted.
- Step 2 – Determine whether emissions of criteria pollutants and precursors would occur in a nonattainment or maintenance area.
- Step 3 – Determine whether the action is exempt from the General Conformity Rule.
- Step 4 – Estimate emissions and compare them with the General Conformity *de minimis* threshold emissions rates.

After completing the General Conformity Applicability review process, if the General Conformity Rule is applicable for the proposed action, then a GCD process is required. The GCD process is an assessment of whether the proposed action conforms to the applicable SIP. Positive General Conformity can be shown through state emission budgets, emission offsets, air quality modeling, or any combination of these three processes.

Per 40 CFR 51.859(d) the Conformity Analysis must be based on the total direct and indirect emissions from the action for:

- nonattainment areas, the year mandated in the CAA for attainment; for maintenance areas, the farthest year for which emissions are projected in the approved maintenance plan;
- the year during which the emissions for the proposed action are projected to be the greatest on an annual basis; and
- any year for which the applicable SIP specifies an emission budget.

2.4 EXEMPTION FROM GENERAL CONFORMITY ANALYSIS

As noted previously, the General Conformity requirements apply to a federal action if the net project emissions equal or exceed the General Conformity *de minimis* emission thresholds. The only exceptions to this applicability criterion are the topical exemptions included in 40 CFR 93.153 (c), (d), and (e). However, the emissions caused by the HECA Project do not meet any of these exempt categories, except the portion of an action that includes major or minor new or modified stationary sources that require a permit under the new source review (NSR) program or the prevention of significant deterioration program (40 CFR 93.153 (d)(1)). In addition to these topical exemptions, the General Conformity regulations allow each federal agency to establish a list of activities that are presumed to conform (40 CFR 93.153 (f)). The U.S. DOE has not established any other exemption actions or activities for HECA.

Emissions from the operation of the HECA Project stationary sources will be permitted through the SJVAPCD under NSR, and are therefore exempt from the GCD, and thus are not included in the total General Conformity evaluation emission analysis.

A Conformity Determination is required for each criteria pollutant and its precursors where the total of direct and indirect annual emissions of the criteria pollutant or its precursors in a federal nonattainment or maintenance area would equal or exceed the General Conformity *de minimis* thresholds. The CAA defines nonattainment areas as geographic regions designated as not meeting one or more of the NAAQS. It requires that a SIP be prepared for each nonattainment area, and a maintenance plan be prepared for each former nonattainment area that has subsequently demonstrated compliance with the standards. The nonattainment or maintenance status and the applicable General Conformity *de minimis* thresholds in all the areas potentially affected by the HECA Project are shown in Table 1. The pollutant with the most nonattainment areas in the state of California is ozone; these areas are shown on Figure 1.

The *de minimis* thresholds are based on the severity of the nonattainment status. In the SJVAB, for example, U.S. EPA has designated the basin as extreme nonattainment for O_3, thus the applicable *de minimis* thresholds for O_3 precursors (VOC and nitrogen oxides (NO_x)) are set to 10 tons per year. For other pollutants (PM_{10}, SO_2, and $PM_{2.5}$), the thresholds are set at 100 tons per year. Although Project-related activities may occur in other regions than those listed in Table 1, those regions are in attainment for all pollutants, and thus are not included in the General Conformity evaluation.

Table 1
Nonattainment and Maintenance Status and General Conformity *De Minimis* Thresholds

Pollutant	Nonattainment/Maintenance Status	General Conformity *De Minimis* Thresholds (tons per year)
San Joaquin Valley Air Basin, California under the jurisdiction of San Joaquin Valley Air Pollution Control District (SJVAPCD)		
O_3	Nonattainment (Extreme)	NA
NO_x (as O_3 precursor)	NA	10
VOC (as O_3 precursor)	NA	10
CO	Maintenance	100
PM_{10} (direct emissions)	Maintenance	100
$PM_{2.5}$ (direct emissions)	Nonattainment	100
SO_2 (as $PM_{2.5}$ precursor)	NA	100
NO_x (as $PM_{2.5}$ precursor)	NA	100
Ammonia or VOC (as $PM_{2.5}$ precursor)	NA	SJVAPCD determined not significant for 2008 $PM_{2.5}$ Plan
Los Angeles-South Coast Air Basin, California under the jurisdiction of South Coast Air Quality Management District (SCAQMD)		
O_3	Nonattainment (Extreme)	NA
NO_x (as O_3 precursor)	NA	10
VOC (as O_3 precursor)	NA	10
NO_x	Maintenance	100

Table 1
Nonattainment and Maintenance Status and General Conformity *De Minimis* Thresholds

Pollutant	Nonattainment/Maintenance Status	General Conformity *De Minimis* Thresholds (tons per year)
CO	Maintenance	100
PM_{10} (direct emissions)	Nonattainment (Serious)	70
$PM_{2.5}$ (direct emissions)	Nonattainment	100
SO_2 (as $PM_{2.5}$ precursor)	NA	100
NO_x (as $PM_{2.5}$ precursor)	NA	100
Ammonia or VOC (as $PM_{2.5}$ precursor)	NA	100
East Kern County, California under the jurisdiction of Eastern Kern Air Pollution Control District (EKAPCD)		
O_3	Nonattainment (Marginal)	NA
NO_x (as O_3 precursor)	NA	100
VOC (as O_3 precursor)	NA	100
PM_{10} (direct emissions)	Nonattainment (Serious)	70
Los Angeles-San Bernardino Counties (West Mojave Desert), California under the jurisdiction of Mojave Desert Air Quality Management District (MDAQMD)		
O_3	Nonattainment (Severe - Part of San Bernardino County)	NA
NO_x (as O_3 precursor)	NA	25
VOC (as O_3 precursor)	NA	25
San Bernardino Co (Mojave Desert), California under the jurisdiction of Mojave Desert Air Quality Management District (MDAQMD)		
PM_{10} (direct emissions)	Nonattainment (Moderate)	100
Sacramento Metro, California under the jurisdiction of Sacramento Metropolitan Air Quality Management District (SMAQMD)		
O_3	Nonattainment (Severe)	NA
NO_x (as O_3 precursor)	NA	25
VOC (as O_3 precursor)	NA	25
CO	Maintenance	100
PM_{10} (direct emissions)	Nonattainment (Moderate)	100
$PM_{2.5}$ (direct emissions)	Nonattainment	100
SO_2 (as $PM_{2.5}$ precursor)	NA	100
NO_x (as $PM_{2.5}$ precursor)	NA	100
Ammonia or VOC (as $PM_{2.5}$ precursor)	NA	100

Table 1
Nonattainment and Maintenance Status and General Conformity *De Minimis* Thresholds

Pollutant	Nonattainment/Maintenance Status	General Conformity *De Minimis* Thresholds (tons per year)
Yuba City-Marysville, California under the jurisdiction of Feather River Air Quality Management District (FRAQMD)		
O_3	Nonattainment (Marginal)	NA
NO_x (as O_3 precursor)	NA	100
VOC (as O_3 precursor)	NA	100
$PM_{2.5}$ (direct emissions)	Nonattainment	100
SO_2 (as $PM_{2.5}$ precursor)	NA	100
NO_x (as $PM_{2.5}$ precursor)	NA	100
Ammonia or VOC (as $PM_{2.5}$ precursor)	NA	100
Chico, California under the jurisdiction of Butte County Air Quality Management District (BCAQMD)		
O_3	Nonattainment (Marginal)	NA
NO_x (as O_3 precursor)	NA	100
VOC (as O_3 precursor)	NA	100
CO	Maintenance	100
$PM_{2.5}$ (direct emissions)	Nonattainment	100
SO_2 (as $PM_{2.5}$ precursor)	NA	100
NO_x (as $PM_{2.5}$ precursor)	NA	100
Ammonia or VOC (as $PM_{2.5}$ precursor)	NA	100
Arizona under the jurisdiction of Arizona Department of Environmental Quality (ADEQ)		
O_3	Nonattainment (Marginal) -Maricopa and Pinal Counties	NA
NO_x (as O_3 precursor)	NA	100
VOC (as O_3 precursor)	NA	100
CO	Maintenance – Maricopa and Pima Counties	100
SO_2	Nonattainment – Pinal county, Maintenance – 4 counties	100
PM_{10} (direct emissions)	Nonattainment or Maintenance – Moderate to Serious – 12 counties	70
$PM_{2.5}$ (direct emissions)	Nonattainment - Santa Cruz and Pinal Counties	100

Table 1
Nonattainment and Maintenance Status and General Conformity *De Minimis* Thresholds

Pollutant	Nonattainment/Maintenance Status	General Conformity *De Minimis* Thresholds (tons per year)
SO_2 (as $PM_{2.5}$ precursor)	NA	100
NO_x (as $PM_{2.5}$ precursor)	NA	100
Ammonia or VOC (as $PM_{2.5}$ precursor)	NA	100
New Mexico under the jurisdiction of New Mexico Environment Department – Air Quality Bureau (NMED-AQB)		
CO	Maintenance (Bernalillo County)	100
SO_2	Maintenance – Grant County	100
PM_{10} (direct emissions)	Nonattainment (Moderate) - Dona Ana County	100

NA = Not Applicable

References: U.S. EPA Greenbook (U.S. EPA, July 20, 2012)

Nonattainment and maintenance criteria pollutant and precursor emissions were calculated for each calendar year of the construction and operation phases of the Project, as well as the year when construction and operational activities overlap. The calculations used methodologies recommended and approved by the CARB and the U.S. EPA. The following are calculation methodologies used for both the construction and operational emissions.

On-road construction and operational vehicles emissions were estimated by multiplying the emission factors generated from the CARB's EMFAC2007 (CARB, 2007a) model by the numbers of vehicles and the mileage driven. Although EMFAC2011 (CARB, 2011) was released in September 2011, it is not yet approved by U.S. EPA for use in federal projects for NEPA and federal conformity analyses; thus, emission factors from EMFAC2007 were applied. Fugitive dust emissions generated in both the construction and operation phases were estimated by using the emission factors obtained from the U.S. EPA AP-42 publication (U.S. EPA, 1995). It should be noted that all the calculated emissions are mitigated emissions that incorporate the Project-committed feasible emission control measures. Detailed construction and operational emissions calculation methodologies are discussed in Section 4.1 and 4.2.

4.1 CONSTRUCTION EMISSIONS

The primary emission sources during construction will include heavy construction equipment, construction vehicles, and fugitive dust from disturbed areas due to grading, excavating, and construction of Project structures. Different areas within the Project Site will be disturbed at different times during the 49-month overall construction period, which includes site preparation, construction, and up to 18 months of commissioning. Each phase has some overlap, but all construction activities are included in the emission estimates. Construction activities will occur 22 days per month, with a single-shift 10-hour workday.

Construction emissions were calculated from sources in three different categories: on-site sources, sources associated with linear construction (e.g., pipelines, transmission line, rail spur, etc.), and off-site sources. On-site sources include construction equipment, delivery trucks entering and exiting the site, and commuter vehicles entering and exiting the site. Linear sources include all construction equipment required for the total linear construction. Off-site sources include worker commuting vehicles and delivery trucks while traveling off-site. Trip distances were based on the assumption that worker commuting vehicles and delivery trucks would travel within Kern County.

The schedule of equipment needed during construction and the estimated number of pieces of equipment that would operate during each month of the construction effort are presented in Appendix A. Emissions from equipment will occur over a 49-month construction period. The list of fueled equipment needed during each month of the construction effort served as the basis for estimating pollutant emissions throughout the term of construction.

Construction equipment and vehicle exhaust emissions were estimated using equipment lists and construction scheduling information provided by the Project design engineering firm. The off-road construction equipment emissions were estimated by multiplying the emission factors generated from CARB's OFFROAD2007 model (CARB, 2007b) by the amount of power produced and by the operating hours, for each equipment type. Emission factors specific to Kern County in calendar year 2013 were used.

Fugitive dust emissions resulting from on-site soil disturbances were estimated using the U.S. EPA AP-42 emission factors for dirt piling, grading, bulldozing and dirt-pushing, and travel on unpaved roads. Dust control efficiencies from 61 to 93 percent for Project Site and linear construction activities were assumed to be achieved by frequent watering, speed control, or application of dust suppressant on unpaved roads.

Emissions from on-road delivery trucks and worker commute trips were estimated using trip generation information presented in Appendix A, and emission factors provided by the EMFAC2007 model for on-road vehicles. Construction workers were assumed to commute to the Project Site from within Kern County.

Table 2 presents the estimated construction emissions by calendar year, from the start of construction in 2013 through the estimated completion in 2017. Emissions were calculated for each year of construction to determine the year with the highest emissions for each pollutant. It is important to note that all the emissions in Table 2 are generated within SJVAB, because the Project is not expected to have delivery trucks or worker commuting vehicles traveling outside of the boundary of SJVAB during construction. Emissions from commissioning of the stationary sources permitted under NSR are not included in the summary in Table 2, because these are exempt from GCD requirements, although emissions from worker commuter vehicles and delivery trucks associated with commissioning are included in the construction emissions. Detailed calculation spreadsheets are provided in Appendix A, which show the calculated emissions for all construction activities and equipment, as well as the data and assumptions used for the calculations.

4.2 OPERATIONAL EMISSIONS

The criteria pollutant emissions generated during operation of the Project will come from the onsite stationary, area, fugitive, mobile sources, and the offsite transportation sources. However, the onsite stationary, area, and fugitive sources will be required to obtain NSR permits from SJVAPCD, and therefore are exempt from the General Conformity analysis pursuant to 40 CFR 93.153.

4.2.1 Onsite Emissions Covered by NSR

The HECA Project will produce low-carbon baseload electricity, low-carbon nitrogen–based fertilizer in an integrated Manufacturing Complex, and CO_2 for EOR. The Gasification Block will feature Mitsubishi Heavy Industries, Ltd. (MHI) oxygen-blown dry-feed gasifier, Shift, Low Temperature Gas Cooling (LTGC), Mercury Removal, Acid Gas Removal (AGR), Sulfur Recovery, Tail Gas Treating, EOR CO_2 Compression Units, and associated utilities to produce hydrogen-rich fuel. Sulfur and mercury components will be removed, and CO_2 will be captured and compressed for EOR and resulting sequestration.

The Combined Cycle Power Block will generate approximately 405 MW of gross power, and will provide approximately 300 MW output of low-carbon baseload electricity. The Power Block will feature one MHI 501 GAC® (Granular-Activated Carbon) combustion turbine generator (CTG) that will be fueled with hydrogen-rich fuel from the gasification plant, and natural gas as a backup fuel; a heat recovery steam generator (HRSG) with duct firing on a combination of hydrogen-rich fuel and Pressure Swing Adsorption (PSA) off-gas; and a condensing steam turbine-generator.

Table 2
Estimated Criteria Pollutant Construction Emissions

Year		CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
		Annual Emissions (tons per year)					
2013 (June - Dec)							
Onsite	Construction Equipment	12.4	23.7	17.1	5.5	0.0	3.8
	Trucks	1.0	2.3	6.8	0.8	0.0	0.6
	Vehicles	0.0	0.0	0.1	0.0	0.0	0.0
	Onsite Total	**13.4**	**26.0**	**23.9**	**6.3**	**0.0**	**4.4**
Offsite	Linears Equipment	0.0	0.0	0.0	0.0	0.0	0.0
	Trucks	4.8	23.9	1.9	1.0	0.0	1.1
	Vehicles	1.8	0.2	0.1	0.0	0.0	0.1
	Offsite Total	**6.6**	**24.1**	**2.0**	**1.0**	**0.0**	**1.1**
2013 Total		**20.0**	**50.1**	**25.9**	**7.3**	**0.1**	**5.5**
2014							
Onsite	Construction Equipment	21.8	35.9	8.4	3.9	0.0	7.0
	Trucks	0.3	0.7	0.2	0.1	0.0	0.2
	Vehicles	0.3	0.0	0.7	0.1	0.0	0.0
	Onsite Total	**22.4**	**36.6**	**9.4**	**4.1**	**0.0**	**7.2**
Offsite	Linears Equipment	11.8	19.7	4.6	1.7	0.0	3.5
	Trucks	2.0	10.3	0.8	0.4	0.0	0.4
	Vehicles	20.2	2.4	0.7	0.2	0.0	0.6
	Offsite Total	**34.0**	**32.4**	**6.1**	**2.3**	**0.1**	**4.6**
2014 Total		**56.4**	**69.0**	**15.4**	**6.4**	**0.1**	**11.9**
2015							
Onsite	Construction Equipment	28.6	47.4	5.7	3.3	0.1	9.4
	Trucks	0.3	0.7	0.2	0.1	0.0	0.2
	Vehicles	0.7	0.1	1.7	0.2	0.0	0.1
	Onsite Total	**29.6**	**48.1**	**7.6**	**3.6**	**0.1**	**9.6**
Offsite	Linears Equipment	2.4	3.9	0.4	0.3	0.0	0.8
	Trucks	2.0	10.3	0.8	0.4	0.0	0.4
	Vehicles	52.2	6.3	1.7	0.6	0.1	1.6
	Offsite Total	**56.7**	**20.5**	**2.9**	**1.2**	**0.1**	**2.8**
2015 Total		**86.3**	**68.6**	**10.5**	**4.8**	**0.1**	**12.4**
2016							
Onsite	Construction Equipment	19.1	29.4	4.2	2.1	0.0	6.3
	Trucks	0.3	0.7	0.2	0.1	0.0	0.2
	Vehicles	0.6	0.0	1.4	0.1	0.0	0.0
	Onsite Total	**20.0**	**30.2**	**5.8**	**2.3**	**0.0**	**6.6**
Offsite	Linears Equipment	0.0	0.0	0.0	0.0	0.0	0.0
	Trucks	2.0	10.3	0.8	0.4	0.0	0.4
	Vehicles	44.4	5.3	1.5	0.5	0.1	1.4
	Offsite Total	**46.5**	**15.6**	**2.3**	**0.9**	**0.1**	**1.8**
2016 Total		**66.4**	**45.8**	**8.1**	**3.2**	**0.1**	**8.4**
2017 (Jan - June)							

Table 2
Estimated Criteria Pollutant Construction Emissions

Year		CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
		Annual Emissions (tons per year)					
Onsite	Construction Equipment	2.7	3.8	0.5	0.3	0.0	0.8
	Trucks	0.1	0.3	0.1	0.0	0.0	0.1
	Vehicles	0.1	0.0	0.2	0.0	0.0	0.0
	Onsite Total	**2.9**	**4.2**	**0.8**	**0.3**	**0.0**	**0.9**
Offsite	Linears Equipment	0.0	0.0	0.0	0.0	0.0	0.0
	Trucks	1.0	5.2	0.4	0.2	0.0	0.2
	Vehicles	6.0	0.7	0.2	0.1	0.0	0.2
	Offsite Total	**7.0**	**5.9**	**0.6**	**0.3**	**0.0**	**0.4**
2017 Total		**9.9**	**10.1**	**1.4**	**0.6**	**0.0**	**1.3**

The Manufacturing Complex is an integrated complex that will produce approximately 1 million tons per year of nitrogen-based fertilizer. Process units used in producing the low-carbon, nitrogen-based fertilizer are the PSA, Carbon Dioxide Purification, and Compression, Ammonia Synthesis, Urea, Urea Pastillation and Storage, Nitric Acid, Ammonium Nitrate, UAN Units, and associated utilities.

The operational emissions from the Project are mainly generated from the combustion of the hydrogen-rich fuel in the Combined Cycle Power Block. Other emission sources are outlined in Table 3. Each emission source can be categorized as part of the Power Block, Gasification Block, Manufacturing Complex, or ancillary equipment as shown in Table 3. Annual emissions from the operation of the sources listed in Table 3 are presented in Table 4.

Table 3
Operational NSR Permitted Emissions Sources

Power Block	Gasification Block	Manufacturing Complex	Ancillary Equipment
• Combustion Turbine (MHI 501GAC®) • Power Block Cooling Tower	• Coal Dryer • Auxiliary Boiler • Gasification Flare • Sulfur Recovery Unit (SRU) Flare • Rectisol® Flare • Tail Gas Thermal Oxidizer • Air Separation Unit (ASU) and Process Cooling Towers • CO_2 Vent • Material Handling Dust collection (Feedstock) • Fugitive Leaks from piping	• Nitric Acid Unit • Urea Absorbers • Urea Pastillation • Ammonium Nitrate Unit • Ammonia Synthesis Unit Start-Up Heater • Material Handling Dust collection (Urea) • Fugitive leaks from piping	• Two Emergency Diesel Generators • Emergency Diesel Firewater Pump

Emissions from the operation of the stationary sources at HECA will be permitted through the SJVAPCD under NSR, and therefore are exempt from GCD, and thus are not included in the total General Conformity evaluation emission analysis. These emissions are presented in Table 4 for reference.

4.2.2 Transportation Emissions

The on-site and off-site mobile sources include the trucks and trains delivering feedstock and removing products that would travel from and to the Project Site on a regular basis, plus the worker commuter vehicles. The emissions from these transportation sources are considered indirect emissions, and are required to be included in the General Conformity analysis. Therefore, all the operational transportation-related emissions of the Project were quantified using similar concepts and techniques used in the construction emissions estimations. These emissions were evaluated for the first full year of operation, as this year will have the highest operational emissions, as more stringent transportation related standards and emission controls will be mandated in later years. The emissions presented in Tables 5-8 represent Project refinements since the initial General Conformity Analysis submission in September 2012.

HECA evaluated two alternatives for the transportation of the feedstock and products to and from the Project Site. Alternative 1, the rail alternative, will transport coal to the Project Site along a new industrial railroad spur that will connect the Project Site to the existing SJVRR Buttonwillow railroad line, north of the Project Site. This railroad spur will also be used to transport some HECA products to market. Alternative 2, the truck alternative, would transport coal to an existing transloading facility in Wasco, then transfer it onto trucks for delivery to the Project Site. In Alternative 2, all products would be transported by truck, and the railroad spur would not be developed.

Table 4
Operational Criteria Pollutant Emissions from the NSR Permitted Sources

Pollutant / Equipment	CO	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC
	tons per year					
HRSG/CTG	89.0	106.5	54.0	54.0	17.1	15.1
Coal Dryer	12.7	17.0	5.6	5.6	2.8	2.4
Auxiliary Boiler	8.6	1.4	1.2	1.2	0.5	0.9
Tail Gas Thermal Oxidizer	11.2	13.4	0.4	0.4	8.3	0.3
CO_2 Vent	124.1	N/A	N/A	N/A	N/A	2.4
Gasification Flare	18.5	2.5	0.03	0.03	0.02	0.01
Rectisol Flare	0.8	0.7	0.03	0.03	0.3	0.01
SRU Flare	0.2	0.1	0.006	0.006	0.4	0.003
Cooling Towers[1]	N/A	N/A	25.5	15.3	N/A	N/A
Emergency Generators[2]	0.8	0.2	0.02	0.02	0.001	0.1
Fire Water Pump	0.2	0.09	0.001	0.001	0.0003	0.01
Nitric Acid Unit	N/A	17	N/A	N/A	N/A	N/A
Urea Pastillation Unit	N/A	N/A	0.2	0.2	N/A	N/A
Ammonium Nitrate Unit	N/A	N/A	0.8	0.8	N/A	N/A
Ammonia Start-Up Heater	0.14	0.04	0.02	0.02	0.01	0.02
Material Handling[3]	N/A	N/A	2.3	2.3	N/A	N/A
Fugitives	6.0	0.005	0.1	0.03	0.1	16.7
Total Annual Emissions[4]	**272.1**	**158.8**	**90.2**	**79.9**	**29.5**	**38.0**

Notes:
1 Includes contributions from all three cooling towers
2 Includes contributions from both emergency generators
3 Material handling emissions are shown as the contribution of all dust collection points.
Total annual emissions represent the maximum annual emissions during operations plus start-up and shut-down emissions
HRSG = Heat Recovery Steam Generator
CTG = combustion turbine generator
CO = carbon monoxide
N/A = not applicable
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter ($PM_{2.5}$ is assumed to equal PM_{10})
SO_2 = sulfur dioxide
VOC = volatile organic compound

The main difference between Alternatives 1 and 2 is the approximately 5-mile railroad spur that would connect the Project Site to the existing SJVRR Buttonwillow railroad line, north of the Project Site, would not be built would not be built under Alternative 2; thus, no feedstock or product would be transported to or from the Project Site via train. The coal would still be transported from New Mexico via train, but would be offloaded at the transloading facility in Wasco, then trucked to the Project Site. There would be no changes to the stationary sources.

Detailed operational emission estimation techniques are described below for Alternatives 1 and 2, separately. The detailed calculations can be found in Appendices B and C for Alternatives 1 and 2, respectively.

Alternative 1

The petcoke trucks will enter the Project Site from Station Road, at Tupman Road, and then proceed south to the truck-unloading station. At the truck-unloading area, each truck will idle for no more than 5 minutes while unloading, and then loop back around through the truck scales and wash rack to exit the Project Site onto Station Road. The product trucks and trains are loaded in the product loading area in the center of the Project Site. The product trucks will also enter and exit the Project Site from Station Road at Tupman Road, and pass through the truck scales and wash rack.

Coal will be transported to the Project Site by train, and a portion of the product will be transported off-site via train. The trains will enter and exit the northwestern corner of the Project Site near Dairy Road and Adohr Road. The train feedstock unloading and product loading stations will be located in the center of the Project Site. In addition to the feedstock and product trains, there will be one dedicated switching engine on site to move either the feedstock or product rail cars.

Emissions associated with the truck movement were calculated using heavy-heavy duty diesel truck emission factors for all trucks, except the operations and maintenance trucks, which were calculated with the light-heavy-duty gasoline and diesel emission factors from EMFAC2007. EMFAC2007 factors vary depending on the calendar year for which the model is run, because the emission factors reflect adopted CARB engine and fuel standards, and are also based on the vehicle fleet age and composition. The vehicle fleet used by EMFAC2007 is based on an analysis of California Department of Motor Vehicles (DMV) registration data, which vary by calendar year and geographic area. Thus, EMFAC2007 runs for earlier calendar years will produce higher emission factors because of older, higher-polluting vehicles still in the vehicle fleet. In addition, the anticipated Project commercial operation date is late 2017. HECA has committed to use a fleet mix of delivery trucks that meets the emission standards from 2010; thus, EMFAC2007 emissions factors for the fleet vehicles for calendar year 2010 were used here in the operational emission calculations.

The fleet mix of line-haul engines that will be used to move feedstock and products for HECA will meet or exceed the U.S. EPA Tier 2+ or 3 standards. Tier 2+ engines are remanufactured engines that meet the revised 2008 standards, and have the same emission limits as new Tier 3 engines. The emissions factors for criteria pollutants for line-haul and switch locomotives were obtained from the U.S. EPA document "Technical Highlights: Emission Factors for Locomotives" for Tier 2+ or 3 engines (U.S. EPA, 2009). The trains' emissions were calculated by multiplying the locomotive emission factors by the numbers of locomotive engines, hours of operations, horsepower, and engine load factor.

On-site feedstock and product train emissions were calculated on the basis that the line-haul engines will operate in Notch 1 or idling mode while on-site; therefore, emissions were conservatively estimated for Notch 1 horsepower. The percentage of total engine horsepower used at Notch 1 was obtained from the "Port of Long Beach Air Emissions Inventory for 2007" (Port of Long Beach, 2010), which was based on data derived from the U.S. EPA (U.S EPA, 1998). Emissions from the switching engine were based on U.S. EPA Tier 3 emission factors and maximum switching engine horsepower of 260 hp.

The off-site feedstock transportation-related emissions are associated with coal transportation by rail, and petcoke transportation by truck. The Project will gasify a blend of 75 percent coal and 25 percent petcoke to produce a hydrogen-rich gas that will be used to produce low-carbon nitrogen-based fertilizer and electricity in a Combined Cycle Power Block. Western sub-bituminous coal will be supplied from mines in New Mexico and transported by rail. The coal trains will travel through New Mexico, Arizona, Mojave Desert Air Quality Management District (MDAQMD), and Eastern Kern Air Pollution Control District (EKAPCD), to the HECA facility in SJVAPCD. Off-site feedstock and product train exhaust emissions were calculated based on an average locomotive load factor from the Port of Long Beach study. Off-site exhaust emissions are based on an average travel speed of 40 miles per hour and the distance of the train route. Empty trains require 76 percent of the horsepower that full trains require.

Fugitive dust emissions from coal trains were calculated using AP-42, Section 13.2.5, Industrial Wind Erosion. Emissions were calculated based on a train speed of 40 miles per hour, the average exposed area of coal in each car, the expected number of coal cars travelling to the Project Site per year, and roughness parameters (roughness height, z_0, and threshold friction velocity, u_t*) appropriate for coal (from AP-42). It has been assumed that all emitted particulate matter will be lost during the first 100 miles of the trip; therefore all particulate matter emissions have been assigned to transportation emissions in New Mexico.

Petcoke most likely will be supplied from refineries in the Los Angeles or Santa Maria areas and transported by trucks. Therefore, the petcoke trucks will travel in SJVAPCD and South Coast Air Quality Management District (SCAQMD).

As a polygeneration facility, the Project is designed to produce several types of products. The products and byproducts that will be shipped off site by either truck or train include:

- Degassed liquid sulfur: Most of the sulfur will be transported by truck to existing buyers, but some will also be transported by rail (approximately 75 percent by truck and 25 percent by rail). Rail is expected to travel on routes only within SJVAPCD, and trucks would travel in both SJVAPCD and SCAQMD.
- Gasification solids: Most of the gasifier solids will be transported by rail for beneficial reuse by regional industries. A smaller portion can be transported to nearby industries by truck. It is estimated that movements would be approximately 75 percent by rail and 25 percent by truck. Rail is expected to travel on routes in SJVAPCD, EKAPCD, and MDAQMD; and trucks would travel within SJVAPCD.
- Urea pastilles: Urea pastilles are small, solid “pellets” of urea. The estimated movements are 75 percent by rail and 25 percent by truck. Rail is expected to travel through SJVAPCD, Sacramento Metro area, Yuba City-Marysville area, Chico area, and other areas in northern California. Trucks would be routed only within SJVAPCD.
- UAN: The UAN solution is expected to be sold to regional users. The estimated movements are 50 percent by rail and 50 percent by truck. Both rail and trucks would be routed only within SJVAPCD.

In addition, trucks carrying the zero-liquid-discharge solids and miscellaneous equipment and supplies would travel to and from the Project Site to various facilities in Kern County. All truck and train routes are calculated to be round-trip routes, and are differentiated by the air basin in which they occur to aid in the conformity evaluation calculations, which are presented in Appendix B. For purposes of the General Conformity evaluation, it should be noted that not all of the affected air districts are nonattainment or maintenance for the same pollutants. Because the General Conformity Rule does not apply to attainment areas, only emissions generated in nonattainment or maintenance areas were calculated.

As expected, the majority of the transportation-related emissions are in the SJVAB. The Project-related transportation emissions in this air basin, as well as in the other Project-affected nonattainment or maintenance areas, are summarized in Table 5. The detailed on-site and off-site transportation emission calculations are included in Appendix B.

Alternative 2

Under the truck alternative, coal would be transported via existing roads from the existing coal transloading facility in Wasco. Under this alternative, the on-site railroad spur would not be developed. Therefore, there would be no trains on-site for feedstock delivery or product removal. All products would be transported by truck.

Compared to Alternative 1, the coal train under Alternative 2 will travel approximately 7 more miles extra in SJVAPCD in order to get to the transloading facility. The coal truck route distance from the transloading facility in Wasco to HECA is 26.5 miles. All product truck routes will remain the same as Alternative 1, with increased truck volume to account for the lack of trains. Emissions were estimated for the on-site and off-site vehicles transporting feedstock and products. Emission factors and calculation techniques described in Alternative 1 were also used to estimate the emissions from the vehicles for Alternative 2.

Table 6 presents the on-site and off-site transportation emissions of criteria pollutants for Alternative 2 in all Project-affected nonattainment or maintenance areas. Detailed transportation emissions and calculations for Alternative 2 are included in Appendix C.

4.3 CONSTRUCTION AND OPERATION OVERLAP YEAR EMISSIONS

Commercial operation of the HECA Project will start in late 2017, and the construction phase of the Project is expected to end in 2017. Therefore, during 2017, both construction and operation activities are expected to occur. To estimate the construction and operation overlap year emissions, the full-year operational emissions were scaled to 4 months, and resulting emissions were added to the 2017 construction emissions. Because there are no construction emissions outside of the SJVAB, and operational emissions in all other nonattainment and maintenance areas are less than the General Conformity thresholds, only emissions in SJVAB are presented in Tables 7 and 8. These tables show the estimated construction and operation overlap year emissions in the SJVAB for Alternatives 1 and 2, respectively. Detailed transportation emissions and calculations for Alternatives 1 and 2 are included in Appendices B and C, respectively.

Table 5
Estimated Criteria Pollutant Operational Emissions for Alternative 1

Nonattainment and Maintenance Area	Emission Sources	Annual Emission Rates (tons per year)					
		CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
San Joaquin Valley, CA	Offsite Train	6.93	26.80	0.43	0.42	0.49	0.74
	Offsite Truck	5.56	9.15	2.51	0.76	0.07	0.77
	Offsite Workers Commuting	4.17	0.48	1.05	0.28	0.01	0.13
	Onsite Train	0.87	2.45	0.04	0.04	0.06	0.12
	Onsite Truck	0.63	0.98	0.15	0.05	0.01	0.16
	Total Emissions	**18.16**	**39.87**	**4.19**	**1.55**	**0.63**	**1.93**
Los Angeles-South Coast Air Basin, CA	Offsite Train	0.00	0.00	0.00	0.00	0.00	0.00
	Offsite Truck	5.17	8.52	2.34	0.71	0.06	0.72
	Total Emissions	**5.17**	**8.52**	**2.34**	**0.71**	**0.06**	**0.72**
Kern County (East Kern), CA	Offsite Train		14.57	0.24			0.40
	Offsite Truck		0.00	0.00			0.00
	Total Emissions		**14.57**	**0.24**			**0.40**
Los Angeles-San Bernardino Counties (West Mojave Desert), CA	Offsite Train		24.80				0.69
	Offsite Truck		0.00				0.00
	Total Emissions		**24.80**				**0.69**
San Bernardino County, CA (Mojave Desert)	Offsite Train			0.70			
	Offsite Truck			0.00			
	Total Emissions			**0.70**			
Sacramento Metro, CA	Offsite Train	0.59	2.30	0.04	0.04	0.04	0.06
	Offsite Truck	0.00	0.00	0.00	0.00	0.00	0.00
	Total Emissions	**0.59**	**2.30**	**0.04**	**0.04**	**0.04**	**0.06**
Yuba City-Marysville, CA	Offsite Train		1.44		0.02	0.03	0.04
	Offsite Truck		0.00		0.00	0.00	0.00
	Total Emissions		**1.44**		**0.02**	**0.03**	**0.04**
Chico, CA	Offsite Train	0.37	1.44		0.02	0.03	0.04
	Offsite Truck	0.00	0.00		0.00	0.00	0.00
	Total Emissions	**0.37**	**1.44**		**0.02**	**0.03**	**0.04**

Table 5
Estimated Criteria Pollutant Operational Emissions for Alternative 1

Nonattainment and Maintenance Area	Emission Sources	Annual Emission Rates (tons per year)					
		CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Arizona	Offsite Train	19.45	75.23	1.22	1.18	1.37	2.08
	Offsite Truck	0.00	0.00	0.00	0.00	0.00	0.00
	Total Emissions	**19.45**	**75.23**	**1.22**	**1.18**	**1.37**	**2.08**
New Mexico	Offsite Train	5.42		4.21		0.38	
	Offsite Truck	0.00		0.00		0.00	
	Total Emissions	**5.42**		**4.21**		**0.38**	

Notes:
The grey cells are for pollutants that are attainment in that area, thus no emissions are presented.
CO = carbon monoxide
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter ($PM_{2.5}$ is assumed to equal PM_{10})
SO_2 = sulfur dioxide
VOC = volatile organic compound

Table 6
Estimated Criteria Pollutant Operational Emissions for Alternative 2

Nonattainment and Maintenance Area	Emission Sources	Annual Emission Rates (tons per year)					
		CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
San Joaquin Valley, CA	Offsite Train	3.74	14.47	0.23	0.23	0.26	0.40
	Offsite Truck	15.59	25.67	7.05	2.12	0.19	2.17
	Offsite Workers Commuting	4.17	0.48	1.05	0.28	0.01	0.13
	Onsite Train	0.00	0.00	0.00	0.00	0.00	0.00
	Onsite Truck	1.52	2.97	0.30	0.10	0.01	0.45
	Total Emission	**25.02**	**43.59**	**8.64**	**2.73**	**0.47**	**3.16**
Los Angeles-South Coast Air Basin, CA	Offsite Train	0.00	0.00	0.00	0.00	0.00	0.00
	Offsite Truck	5.26	8.67	2.38	0.72	0.06	0.73
	Total Emission	**5.26**	**8.67**	**2.38**	**0.72**	**0.06**	**0.73**
Kern County (East Kern), CA	Offsite Train		12.81	0.21			0.35
	Offsite Truck		0.00	0.00			0.00
	Total Emission		**12.81**	**0.21**			**0.35**
Los Angeles-San Bernardino Counties (West Mojave Desert), CA	Offsite Train		24.80				0.69
	Offsite Truck		0.00				0.00
	Total Emission		**24.80**				**0.69**
San Bernardino County, CA (Mojave Desert)	Offsite Train			0.68			
	Offsite Truck			0.00			
	Total Emission			**0.68**			
Sacramento Metro, CA	Offsite Train	0.00	0.00	0.00	0.00	0.00	0.00
	Offsite Truck	0.00	0.00	0.00	0.00	0.00	0.00
	Total Emission	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Yuba City-Marysville, CA	Offsite Train		0.00		0.00	0.00	0.00
	Offsite Truck		0.00		0.00	0.00	0.00
	Total Emission		**0.00**		**0.00**	**0.00**	**0.00**

Table 6
Estimated Criteria Pollutant Operational Emissions for Alternative 2

Nonattainment and Maintenance Area	Emission Sources	Annual Emission Rates (tons per year)					
		CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Chico, CA	Offsite Train	0.00	0.00		0.00	0.00	0.00
	Offsite Truck	0.00	0.00		0.00	0.00	0.00
	Total Emission	**0.00**	**0.00**		**0.00**	**0.00**	**0.00**
Arizona	Offsite Train	19.45	75.23	1.22	1.18	1.37	2.08
	Offsite Truck	0.00	0.00	0.00	0.00	0.00	0.00
	Total Emission	**19.45**	**75.23**	**1.22**	**1.18**	**1.37**	**2.08**
New Mexico	Offsite Train	5.42		4.21		0.38	
	Offsite Truck	0.00		0.00		0.00	
	Total Emission	**5.42**		**4.21**		**0.38**	

Notes:
The grey cells are for pollutants that are attainment in that area, thus no emissions are presented.
CO = carbon monoxide
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter ($PM_{2.5}$ is assumed to equal PM_{10})
SO_2 = sulfur dioxide
VOC = volatile organic compound

Table 7
Estimated Criteria Pollutant Emissions during the Construction and Operation Overlap Year (2017) in San Joaquin Valley Air Basin for Alternative 1

Type	Emission Sources	Annual Emission Rates (tons per year)					
		CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Construction	Onsite Construction Equipment	2.65	3.84	0.48	0.27	0.00	0.83
	Onsite Trucks	0.15	0.34	0.09	0.03	0.00	0.09
	Onsite Vehicles	0.08	0.01	0.22	0.02	0.00	0.01
	Onsite Total	**2.88**	**4.18**	**0.79**	**0.32**	**0.01**	**0.93**
	Offsite Linears Equipment	0.00	0.00	0.00	0.00	0.00	0.00
	Offsite Trucks	1.02	5.16	0.42	0.21	0.00	0.22
	Offsite Vehicles	5.98	0.72	0.20	0.07	0.01	0.18
	Offsite Total	**6.99**	**5.87**	**0.61**	**0.28**	**0.01**	**0.41**
	Total Construction Emissions	**9.87**	**10.06**	**1.40**	**0.60**	**0.02**	**1.34**
Operation	Offsite Train	2.31	8.93	0.14	0.14	0.16	0.25
	Offsite Truck	1.85	3.05	0.84	0.25	0.02	0.26
	Offsite Workers Commuting	1.39	0.16	0.35	0.09	0.00	0.04
	Onsite Train	0.29	0.82	0.01	0.01	0.02	0.04
	Onsite Truck	0.21	0.33	0.05	0.02	0.00	0.05
	Total Operational Emissions	**6.05**	**13.29**	**1.40**	**0.52**	**0.21**	**0.64**
Total Construction and Operation Overlap Emissions		**15.92**	**23.35**	**2.80**	**1.12**	**0.23**	**1.98**

Notes:
CO = carbon monoxide
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter ($PM_{2.5}$ is assumed to equal PM_{10})
SO_2 = sulfur dioxide
VOC = volatile organic compound

Table 8
Estimated Criteria Pollutant Emissions during the Construction and Operation Overlap Year (2017) in San Joaquin Valley Air Basin for Alternative 2

Type	Emission Sources	Annual Emission Rates (tons per year)					
		CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Construction	Onsite Construction Equipment	2.65	3.84	0.48	0.27	0.00	0.83
	Onsite Trucks	0.15	0.34	0.09	0.03	0.00	0.09
	Onsite Vehicles	0.08	0.01	0.22	0.02	0.00	0.01
	Onsite Total	**2.88**	**4.18**	**0.79**	**0.32**	**0.01**	**0.93**
	Offsite Linears Equipment	0.00	0.00	0.00	0.00	0.00	0.00
	Offsite Trucks	1.02	5.16	0.42	0.21	0.00	0.22
	Offsite Vehicles	5.98	0.72	0.20	0.07	0.01	0.18
	Offsite Total	**6.99**	**5.87**	**0.61**	**0.28**	**0.01**	**0.41**
	Total Construction Emissions	**9.87**	**10.06**	**1.40**	**0.60**	**0.02**	**1.34**
Operation	Offsite Train	1.25	4.82	0.08	0.08	0.09	0.13
	Offsite Truck	5.20	8.56	2.35	0.71	0.06	0.72
	Offsite Workers Commuting	1.39	0.16	0.35	0.09	0.00	0.04
	Onsite Train	0.00	0.00	0.00	0.00	0.00	0.00
	Onsite Truck	0.51	0.99	0.10	0.03	0.00	0.15
	Total Operational Emissions	**8.34**	**14.53**	**2.88**	**0.91**	**0.16**	**1.05**
Total Construction and Operation Overlap Emissions		**18.21**	**24.59**	**4.28**	**1.51**	**0.17**	**2.39**

Notes:
CO = carbon monoxide
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter ($PM_{2.5}$ is assumed to equal PM_{10})
SO_2 = sulfur dioxide
VOC = volatile organic compound

The general conformity applicability reviews for Alternatives 1 and 2 from HECA are presented below in Tables 9 and 10, respectively. These tables summarize and compare the emissions by year associated with the HECA Project, with the different applicable General Conformity *de minimis* thresholds in each of the affected nonattainment and maintenance areas.

As shown in Tables 9 and 10, for both Alternatives 1 and 2, the annual emissions from the HECA Project are below the applicable General Conformity *de minimis* thresholds for CO, PM_{10}, $PM_{2.5}$, and SO_2 for each year of construction, construction and operation overlap, and operation, in all nonattainment and maintenance areas. Construction emissions of NO_x exceed the General Conformity *de minimis* threshold each year of construction in the SJVAB. Construction emissions of VOC exceed the General Conformity *de minimis* threshold in years 2014 and 2015 of construction in the SJVAB. Operational emissions of NO_x exceed the General Conformity *de minimis* threshold each year of operation in the SJVAB. NO_x emissions also exceed the General Conformity *de minimis* threshold during the construction and operation overlap year. Therefore, a GCD is required for NO_x for construction and operation in the SJVAB. A GCD in the SJVAB is also required for VOC during construction.

Table 9
Comparison of the Emissions from HECA with the General Conformity *De Minimis* Thresholds – Construction and Operation Alternative 1

Year/Type	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
	Annual emissions (tons per year)					
San Joaquin Valley Air Basin, CA						
2013 – Construction	20.0	50.1	25.9	7.3	0.1	5.5
2014 – Construction	56.4	69.0	15.4	6.4	0.1	11.9
2015 – Construction	86.3	68.6	10.5	4.8	0.1	12.4
2016 – Construction	66.4	45.8	8.1	3.2	0.1	8.4
2017 – Construction and Operation Overlap	15.9	23.3	2.8	1.1	0.2	2.0
2018 and Beyond – Operation	18.2	39.9	4.2	1.5	0.6	1.9
Applicable general conformity threshold	100	10	100	100	100	10
Maximum emissions	86.3	69.0	25.9	7.3	0.6	12.4
Exceed threshold?	No	Yes (all years)	No	No	No	Yes (2014 and 2015)
Los Angeles-South Coast Air Basin, CA						
2017 – Operation	1.7	2.8	0.8	0.2	0.0	0.2
2018 and Beyond – Operation	5.2	8.5	2.3	0.7	0.1	0.7
Applicable general conformity threshold	100	10	70	100	100	10
Maximum emissions	5.2	8.5	2.3	0.7	0.1	0.7
Exceed threshold?	No	No	No	No	No	No

Table 9
Comparison of the Emissions from HECA with the General Conformity *De Minimis* Thresholds – Construction and Operation Alternative 1

Year/Type	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
	Annual emissions (tons per year)					
East Kern County, CA						
2017 – Operation	NA	4.9	0.1	NA	NA	0.1
2018 and Beyond – Operation	NA	14.6	0.2	NA	NA	0.4
Applicable general conformity threshold	NA	100	70	NA	NA	100
Maximum emissions	NA	14.6	0.2	NA	NA	0.4
Exceed threshold?	NA	No	No	NA	NA	No
Los Angeles-San Bernardino Counties (West Mojave Desert), CA						
2017 – Operation	NA	8.3	NA	NA	NA	0.2
2018 and Beyond – Operation	NA	24.8	NA	NA	NA	0.7
Applicable general conformity threshold	NA	25	NA	NA	NA	25
Maximum emissions	NA	24.8	NA	NA	NA	0.7
Exceed threshold?	NA	No	NA	NA	NA	No
San Bernardino Co, CA (Mojave Desert)						
2017 – Operation	NA	NA	0.2	NA	NA	NA
2018 and Beyond – Operation	NA	NA	0.7	NA	NA	NA
Applicable general conformity threshold	NA	NA	100	NA	NA	NA
Maximum emissions	NA	NA	0.7	NA	NA	NA
Exceed threshold?	NA	NA	No	NA	NA	NA
Sacramento Metro, CA						
2017 – Operation	0.2	0.8	0.01	0.01	0.01	0.02
2018 and Beyond – Operation	0.6	2.3	0.04	0.04	0.04	0.06
Applicable general conformity threshold	100	25	100	100	100	25
Maximum emissions	0.6	2.3	0.04	0.04	0.04	0.06
Exceed threshold?	No	No	No	No	No	No
Yuba City-Marysville, CA						
2017 – Operation	NA	0.48	NA	0.01	0.01	0.01
2018 and Beyond – Operation	NA	1.44	NA	0.02	0.03	0.04
Applicable general conformity threshold	NA	100	NA	100	100	100
Maximum emissions	NA	1.44	NA	0.02	0.03	0.04
Exceed threshold?	NA	No	NA	No	No	No

Table 9
Comparison of the Emissions from HECA with the General Conformity *De Minimis* Thresholds – Construction and Operation Alternative 1

Year/Type	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
	Annual emissions (tons per year)					
Chico, CA						
2017 – Operation	0.12	0.48	NA	0.01	0.01	0.01
2018 and Beyond – Operation	0.37	1.44	NA	0.02	0.03	0.04
Applicable general conformity threshold	100	100	NA	100	100	100
Maximum emissions	0.37	1.44	NA	0.02	0.03	0.04
Exceed threshold?	No	No	NA	No	No	No
Arizona						
2017 – Operation	6.48	25.08	0.41	0.39	0.46	0.69
2018 and Beyond – Operation	19.45	75.23	1.22	1.18	1.37	2.08
Applicable general conformity threshold	100	100	70	100	100	100
Maximum emissions	19.45	75.23	1.22	1.18	1.37	2.08
Exceed threshold?	No	No	No	No	No	No
New Mexico						
2017 – Operation	1.81	NA	1.40	NA	0.13	NA
2018 and Beyond – Operation	5.43	NA	4.21	NA	0.38	NA
Applicable general conformity threshold	100	NA	100	NA	100	NA
Maximum emissions	5.43	NA	4.21	NA	0.38	NA
Exceed threshold?	No	NA	No	NA	No	NA

Notes:
CO = carbon monoxide
NA = Not Applicable
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter ($PM_{2.5}$ is assumed to equal PM_{10})
SO_2 = sulfur dioxide
VOC = volatile organic compound

Table 10
Comparison of the Emissions from HECA with the General Conformity *De Minimis* Thresholds – Construction and Operation Alternative 2

Year	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
	Annual emissions (tons per year)					
San Joaquin Valley Air Basin, CA						
2013 – Construction	20.0	50.1	25.9	7.3	0.1	5.5
2014 – Construction	56.4	69.0	15.4	6.4	0.1	11.9
2015 – Construction	86.3	68.6	10.5	4.8	0.1	12.4
2016 – Construction	66.4	45.8	8.1	3.2	0.1	8.4
2017 – Construction Operation Overlap	18.21	24.59	4.28	1.51	0.17	2.39
2018 and Beyond – Operation	25.02	43.59	8.64	2.73	0.47	3.16
Applicable general conformity threshold	100	10	100	100	100	10
Maximum emissions	86.3	69.0	25.9	7.3	0.4	12.4
Exceed threshold?	No	Yes (all years)	No	No	No	Yes (2014 and 2015)
Los Angeles-South Coast Air Basin, CA						
2017 – Operation	1.75	2.89	0.79	0.24	0.02	0.24
2018 and Beyond – Operation	5.26	8.67	2.38	0.72	0.06	0.73
Applicable general conformity threshold	100	10	70	100	100	10
Maximum emissions	5.26	8.67	2.38	0.72	0.06	0.73
Exceed threshold?	No	No	No	No	No	No
East Kern County, CA						
2017 – Operation	NA	4.27	0.07	NA	NA	0.12
2018 and Beyond – Operation	NA	12.81	0.21	NA	NA	0.35
Applicable general conformity threshold	NA	100	70	NA	NA	100
Maximum emissions	NA	12.81	0.21	NA	NA	0.35
Exceed threshold?	NA	No	No	NA	NA	No
Los Angeles-San Bernardino Counties (West Mojave Desert), CA						
2017 – Operation	NA	8.27	NA	NA	NA	0.23
2018 and Beyond – Operation	NA	24.8	NA	NA	NA	0.69
Applicable general conformity threshold	NA	25	NA	NA	NA	25
Maximum emissions	NA	24.8	NA	NA	NA	0.69
Exceed threshold?	NA	No	NA	NA	NA	No

Table 10
Comparison of the Emissions from HECA with the General Conformity *De Minimis* Thresholds – Construction and Operation Alternative 2

Year	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
	Annual emissions (tons per year)					
San Bernardino Co, CA (Mojave Desert)						
2017 – Operation	NA	NA	0.23	NA	NA	NA
2018 and Beyond – Operation	NA	NA	0.68	NA	NA	NA
Applicable general conformity threshold	NA	NA	100	NA	NA	NA
Maximum emissions	NA	NA	0.68	NA	NA	NA
Exceed threshold?	NA	NA	No	NA	NA	NA
Sacramento Metro, CA						
2017 – Operation	0	0	0	0	0	0
2018 and Beyond – Operation	0	0	0	0	0	0
Applicable general conformity threshold	100	25	100	100	100	25
Maximum emissions	0	0	0	0	0	0
Exceed threshold?	No	No	No	No	No	No
Yuba City-Marysville, CA						
2017 – Operation	NA	0	NA	0	0	0
2018 and Beyond – Operation	NA	0	NA	0	0	0
Applicable general conformity threshold	NA	100	NA	100	100	100
Maximum emissions	NA	0	NA	0	0	0
Exceed threshold?	NA	No	NA	No	No	No
Chico, CA						
2017 – Operation	0	0	NA	0	0	0
2018 and Beyond – Operation	0	0	NA	0	0	0
Applicable general conformity threshold	100	100	NA	100	100	100
Maximum emissions in this area	0	0	NA	0	0	0
Exceed threshold?	No	No	NA	No	No	No
Arizona						
2017 – Operation	6.48	25.08	0.41	0.39	0.46	0.69
2018 and Beyond – Operation	19.45	75.23	1.22	1.18	1.37	2.08
Applicable general conformity threshold	100	100	70	100	100	100
Maximum emissions	19.45	75.23	1.22	1.18	1.37	2.08
Exceed threshold?	No	No	No	No	No	No

Table 10
Comparison of the Emissions from HECA with the General Conformity *De Minimis* Thresholds – Construction and Operation Alternative 2

Year	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
	Annual emissions (tons per year)					
New Mexico						
2017 – Operation	1.81	NA	1.40	NA	0.13	NA
2018 and Beyond – Operation	5.42	NA	4.21	NA	0.38	NA
Applicable general conformity threshold	100	NA	100	NA	100	NA
Maximum emissions	5.42	NA	4.21	NA	0.38	NA
Exceed threshold?	No	NA	No	NA	No	NA

Notes:
CO = carbon monoxide
NA = Not Applicable
NOX = nitrogen oxides
PM10 = particulate matter less than 10 microns in diameter
PM2.5 = particulate matter less than 2.5 microns in diameter (PM2.5 is assumed to equal PM10)
SO2 = sulfur dioxide
VOC = volatile organic compound

As indicated in Section 5, a GCD is required for NO_x for construction and operation, and for VOCs during construction in the SJVAB, for both Alternatives 1 and 2.

According to the U.S. EPA and U.S. DOE General Conformity Guidance, a full GCD is only required for the federal agency approved alternative. As of the writing of this GCD report, the U.S. DOE has not approved an alternative yet. Therefore, a General Conformity evaluation was conducted for both alternatives. Both Alternatives 1 and 2 have identical NO_x and VOC construction emissions for all calendar years of the construction phase. NO_x emissions during the construction and operation overlap year and the operation years are different for Alternatives 1 and 2. Alternative 2 NO_x emissions are higher than those of Alternative 1 in SJVAB, although both Alternatives are greater than the GCD threshold for all years. Regardless of the Alternative, HECA has identified the criteria and options that can be used to demonstrate that the federal action conforms to the applicable SIP.

The SJVAPCD staff was consulted, and it was determined that the adopted 2007 8-hour O_3 plan does not include HECA construction or operational direct or indirect emissions in the emission inventory, nor do the growth forecasts account for the emissions from HECA. Therefore, to achieve General Conformity for the HECA project, it is necessary to incorporate the HECA emissions in the next SIP revision, develop additional positive mitigation measures, or obtain emissions offsets in the SJVAB.

SJVAPCD staff recommended that the Project emissions of NO_x and VOC be fully offset through the SJVAPCD's Emission Reduction Incentive Program (ERIP). The ERIP is a thoroughly audited and highly respected grant-based program that contracts with third parties receiving grant funds to implement emission reduction projects, and then assures tracks and enforces those reductions. The SJVAPCD serves as both the administrator of the projects and the verifier of the emission reductions. Examples of projects funded in the past include electrification of stationary internal combustion engines; replacement of old heavy-duty trucks with new, cleaner trucks; and replacement of old farm tractors. The SJVAPCD will fund projects within the SJVAB that will produce real, quantifiable, enforceable, and surplus emission reductions, contemporaneously with Project emission increases.

Therefore the Project has entered into an enforceable commitment with the SJVAPCD to participate in the ERIP. A copy of the Mitigation Agreement setting forth this commitment is attached as Appendix D. The HECA Project's participation in the ERIP will provide pound-for-pound offsets of emissions that exceed the General Conformity thresholds to offset all emissions subject to General Conformity down to zero. The offsets will cover NO_x emissions during all years of construction and operations, as well as VOCs during all years of construction, as the threshold is exceeded in 2014 and 2015. The required offsets will be based on the maximum potential emissions for either Alternative 1 or 2. Through this mechanism, construction and operational emissions of NO_x and VOC from the Project which exceed the General Conformity thresholds will be fully offset and the federal action will conform to the SIP pursuant to Title 40, Code of Federal Regulations, Part 93, Subpart B, Section 93.158(a)(2) and/or Section 93.158(a)(5)(iii). An explanation of the basis of the fees to be paid into the ERIP is provided below.

Emission fees to be paid by HECA into the ERIP are based on the SJVAPCD's Indirect Source Control (ISR) rule, Rule 9510, and include a 4% administration fee to cover SJVAPCD costs related to contracting and enforcing the actual emission reductions resulting from the ERIP. The amount of the fee for both NO_x and VOC emissions is \$9,350 per ton per year. Based on the emissions information presented in Section 5 above, the amount of the fees to be paid by HECA into the ERIP is presented in Table 11.

Table 11
ERIP Conformity Mitigation Fee

Emissions Subject to General Conformity Mitigation					
	NOx	VOC	Mitigation Fee[1]	Administration Fee[2]	
HECA Project	(tpy)	(tpy)	($/ton)		Cost
Construction (total)	243.6	39.5	9,350	4%	$ 2,752,864
Operations (max year)[3]	43.6	0	9,350	4%	$ 4,238,692
Total:					**$ 6,991,556**

Notes:

1. Mitigation Fee defined in SJVAPCD Rule 9510 (ISR)
2. Administration Fee set forth in SJVAPCD Rule 3180
3. Construction emissions are the same in both Alternatives; for Operational emissions, the higher emissions from Alternative 2 have been used.

As required by 40 CFR 93 Subpart B, an evaluation of the General Conformity was performed for the HECA Project for all the affected nonattainment and maintenance areas in the states of California, Arizona, and New Mexico. Criteria pollutant emissions generated in each Project-affected area from activities associated with the Project construction and operation were calculated and compared to the General Conformity *de minimis* thresholds to assess whether a GCD is required.

The estimated emissions indicate that the total direct and indirect construction and operational emissions of CO, PM_{10}, $PM_{2.5}$, and SO_2 are below the applicable General Conformity thresholds for all years of construction and operation in all nonattainment and maintenance areas. Construction and operational emissions of NO_x exceed the General Conformity threshold during construction and operation in the SJVAB. Construction emissions of VOC exceed the General Conformity threshold in the SJVAB. Thus a GCD for NO_x for during construction and operation and for VOC during construction in the SJVAB is required.

The Project has entered into an enforceable commitment with the SJVAPCD to participate in its Emission Reduction Incentive Program (ERIP). The HECA Project's participation in the ERIP will provide pound-for-pound offsets of emissions that exceed the General Conformity thresholds to offset all emissions subject to General Conformity down to zero. The offsets will cover NO_x emissions during all years of construction and operations, as well as VOCs during all years of construction, as the threshold is exceeded in 2014 and 2015. Through this mechanism, construction and operational emissions of NO_x and VOC from the Project which exceed the General Conformity thresholds will be fully offset and the federal action will conform to the SIP pursuant to Title 40, Code of Federal Regulations, Part 93, Subpart B, Section 93.158(a)(2).

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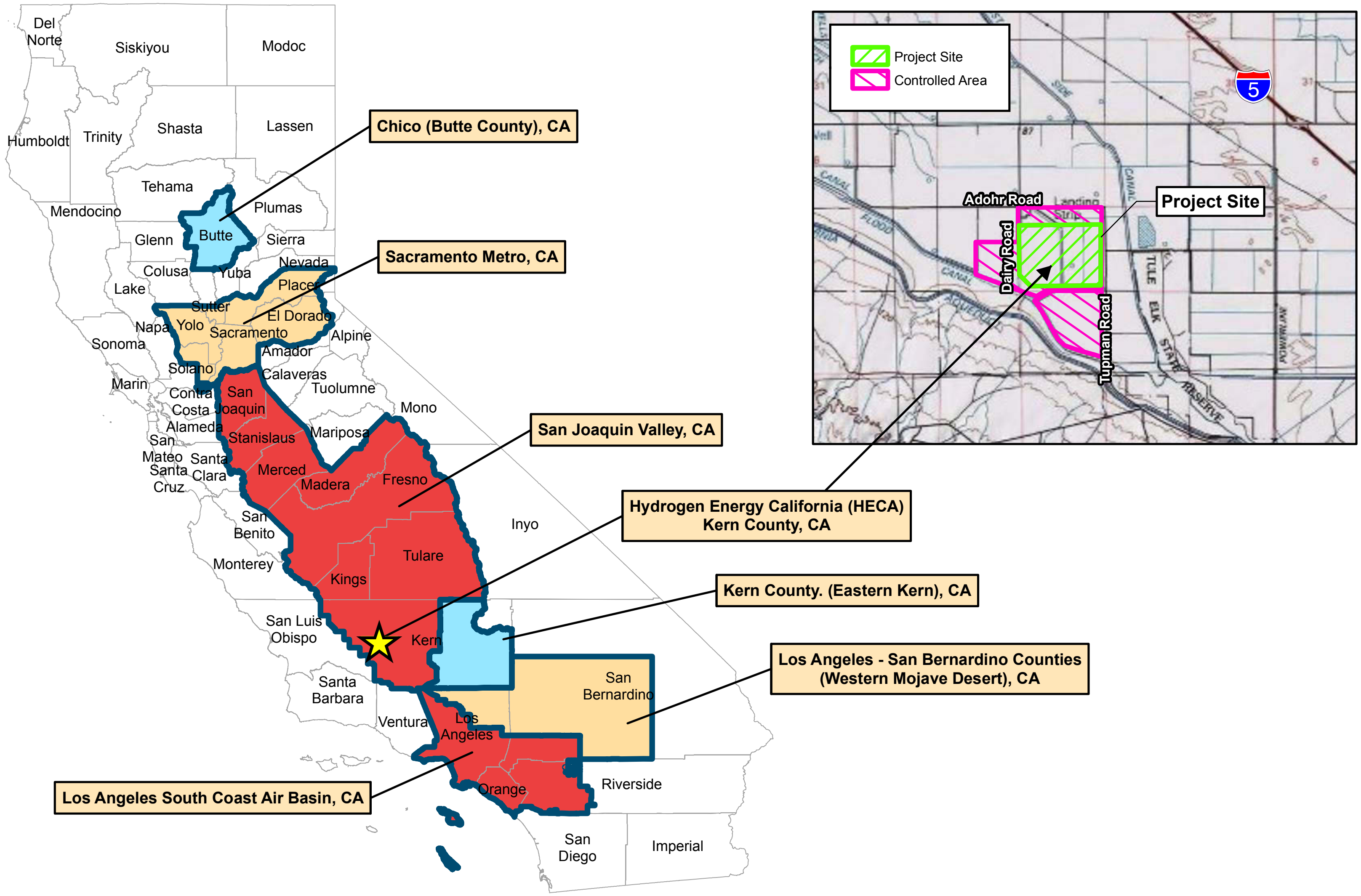
FIGURES



8-hour Ozone Nonattainment Areas

8-hour Ozone Nonattainment Classification

- Extreme
- Severe 15
- Serious
- Moderate
- Marginal

SOURCES: ESRI, EPA.

PROJECT LOCATION AND PROJECT AFFECTED OZONE NONATTAINMENT AREAS IN CALIFORNIA

URS

75 0 75 150 Miles

SCALE: 1" = 150 miles (1:9,504,000)
SCALE CORRECT WHEN PRINTED AT 8.5X11

CREATED BY: PM	DATE: 8/23/2012	FIG. NO: 1
PM: JM	PROJ. NO: 28068052.50501	

Path: G:\gis\projects\1577\28068052\map_docs\mxd\EPA_8_Hour_Zones.mxd, paul_moreno, 8/23/2012, 2:41:34 PM

APPENDIX A

DETAILED CONSTRUCTION EMISSION CALCULATIONS

Estimated Annual Calendar Year Construction Emissions of Criteria Pollutants (tons/yr)							
Year		CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
		Annual Emissions (tons per year)					
2013 (June - Dec)							
Onsite	Construction Equipment	12.4	23.7	17.1	5.5	0.0	3.8
	Trucks	1.0	2.3	6.8	0.8	0.0	0.6
	Vehicles	0.0	0.0	0.1	0.0	0.0	0.0
	Onsite Total	**13.4**	**26.0**	**23.9**	**6.3**	**0.0**	**4.4**
Offsite	Linears Equipment	0.0	0.0	0.0	0.0	0.0	0.0
	Trucks	4.8	23.9	1.9	1.0	0.0	1.1
	Vehicles	1.8	0.2	0.1	0.0	0.0	0.1
	Offsite Total	**6.6**	**24.1**	**2.0**	**1.0**	**0.0**	**1.1**
2013 Total		**20.0**	**50.1**	**25.9**	**7.3**	**0.1**	**5.5**
2014							
Onsite	Construction Equipment	21.8	35.9	8.4	3.9	0.0	7.0
	Trucks	0.3	0.7	0.2	0.1	0.0	0.2
	Vehicles	0.3	0.0	0.7	0.1	0.0	0.0
	Onsite Total	**22.4**	**36.6**	**9.4**	**4.1**	**0.0**	**7.2**
Offsite	Linears Equipment	11.8	19.7	4.6	1.7	0.0	3.5
	Trucks	2.0	10.3	0.8	0.4	0.0	0.4
	Vehicles	20.2	2.4	0.7	0.2	0.0	0.6
	Offsite Total	**34.0**	**32.4**	**6.1**	**2.3**	**0.1**	**4.6**
2014 Total		**56.4**	**69.0**	**15.4**	**6.4**	**0.1**	**11.9**
2015							
Onsite	Construction Equipment	28.6	47.4	5.7	3.3	0.1	9.4
	Trucks	0.3	0.7	0.2	0.1	0.0	0.2
	Vehicles	0.7	0.1	1.7	0.2	0.0	0.1
	Onsite Total	**29.6**	**48.1**	**7.6**	**3.6**	**0.1**	**9.6**
Offsite	Linears Equipment	2.4	3.9	0.4	0.3	0.0	0.8
	Trucks	2.0	10.3	0.8	0.4	0.0	0.4
	Vehicles	52.2	6.3	1.7	0.6	0.1	1.6
	Offsite Total	**56.7**	**20.5**	**2.9**	**1.2**	**0.1**	**2.8**
2015 Total		**86.3**	**68.6**	**10.5**	**4.8**	**0.1**	**12.4**
2016							
Onsite	Construction Equipment	19.1	29.4	4.2	2.1	0.0	6.3
	Trucks	0.3	0.7	0.2	0.1	0.0	0.2
	Vehicles	0.6	0.0	1.4	0.1	0.0	0.0
	Onsite Total	**20.0**	**30.2**	**5.8**	**2.3**	**0.0**	**6.6**
Offsite	Linears Equipment	0.0	0.0	0.0	0.0	0.0	0.0
	Trucks	2.0	10.3	0.8	0.4	0.0	0.4
	Vehicles	44.4	5.3	1.5	0.5	0.1	1.4
	Offsite Total	**46.5**	**15.6**	**2.3**	**0.9**	**0.1**	**1.8**
2016 Total		**66.4**	**45.8**	**8.1**	**3.2**	**0.1**	**8.4**
2017 (Jan - June)							
Onsite	Construction Equipment	2.65	3.84	0.48	0.27	0.00	0.83
	Trucks	0.15	0.34	0.09	0.03	0.00	0.09
	Vehicles	0.08	0.01	0.22	0.02	0.00	0.01
	Onsite Total	**2.88**	**4.18**	**0.79**	**0.32**	**0.01**	**0.93**
Offsite	Linears Equipment	0.00	0.00	0.00	0.00	0.00	0.00
	Trucks	1.02	5.16	0.42	0.21	0.00	0.22
	Vehicles	5.98	0.72	0.20	0.07	0.01	0.18
	Offsite Total	**6.99**	**5.87**	**0.61**	**0.28**	**0.01**	**0.41**
2017 Total		**9.9**	**10.1**	**1.4**	**0.6**	**0.0**	**1.3**

CO	MONTHLY EMISSIONS (lbs/day)																																																
CONSTRUCTION VEHICLES	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
ON-SITE																																																	
On-Road Vehicles																																																	
18 cy fill mat'l haul truck	0	0	13	13	26	26	26	26	13	13	13	13	7	7	7	7	7	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	4	4	4	1	1	1	0	0	0	0	0	0	0
Bus	3	3	3	3	4	4	4	4	4	4	7	7	7	7	7	7	9	9	9	13	13	13	13	18	18	18	18	18	18	18	18	18	18	18	18	16	16	16	13	13	7	7	4	4	3	3	3	1	1
Concrete Pumper Truck	0	0	0	0	0	3	3	3	3	3	3	3	3	4	4	4	3	3	3	3	3	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dump Truck	4	5	5	4	4	4	4	4	4	4	3	3	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	3	3	3	3	3	3	3	3	3	4	4	4	3	1	1	1	1	1	0	0	0	0
Diesel Tractor (Yard Dog)	0	0	0	0	0	3	3	3	3	3	3	6	6	6	6	6	12	12	12	12	12	12	12	15	15	15	15	15	15	15	15	15	15	15	15	6	6	6	6	6	6	6	0	0	0	0	0	0	0
Service Truck - 1 ton	3	3	3	5	5	5	5	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	1	1	1	1	1	1	1
Pile Driver Truck	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck - Fuel/Lube	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0
Tractor Truck 5th Wheel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trucks - Pickup 3/4 ton	3	3	3	3	3	4	4	5	10	10	10	10	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	10	10	6	6	6	6	3
Trucks - 3 ton	1	1	1	1	1	3	3	3	5	5	5	5	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	5	4	4	4	4	3	3	3	1	1	1	1	0	0	0
Truck - Water	7	7	7	7	7	7	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	3	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	1	1	1	1	1	1	1
Off Road Vehicles																																																	
Air Compressor 185 CFM	3	3	3	3	4	4	4	4	4	4	4	4	4	8	8	8	10	10	10	13	13	13	13	15	15	15	15	15	15	15	15	15	15	15	15	10	10	10	8	8	8	8	5	5	5	3	3	1	1
Air Compressor 750 CFM	0	0	0	0	2	2	2	2	3	3	3	3	3	3	3	6	6	6	6	6	6	6	6	6	6	6	6	6	6	3	3	3	3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Articulating Boom Platform	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bob cat loader	0	0	2	2	2	2	2	8	8	8	8	8	6	6	6	6	6	6	4	4	4	4	4	4	0	0	0	0	0	0	0	0	0	0	0	2	2	2	2	2	2	2	0	0	0	0	0	0	0
Bulldozer D10R	17	17	17	11	11	11	11	11	11	6	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bulldozer D6C	9	9	9	9	6	6	6	6	6	6	6	3	3	3	3	3	0	0	0	0	0	0	0	0	0	0	0	3	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Concrete Trowel Machine	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	1	1	1	1	1	1	0	0	0	0	0	0	0
Concrete Vibrators	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cranes - Mobile 35 ton	0	0	0	0	0	0	2	2	2	6	6	6	6	11	11	11	11	11	11	11	11	11	11	11	11	11	8	8	8	8	8	8	8	8	3	3	3	3	3	3	3	3	3	3	3	2	2	2	2
Cranes - Mobile 45 ton	0	0	0	0	0	0	0	0	0	0	4	4	4	4	4	4	4	4	8	8	8	8	8	8	8	8	8	8	8	4	4	4	4	4	4	4	4	4	4	4	2	2	0	0	0	0	0	0	0
Crane - Mobile 65 ton	0	0	0	0	0	0	0	0	0	0	0	2	2	4	8	10	10	10	12	12	12	12	12	12	12	12	12	12	12	12	10	10	8	4	4	4	4	4	2	2	2	2	2	2	2	0	0	0	0
Cranes 100 / 150 ton cap	0	0	0	0	0	0	0	0	0	0	1	1	3	3	4	4	5	5	5	5	5	5	5	5	5	5	5	5	3	3	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel Powered Welder	0	0	0	3	3	3	3	3	3	3	3	3	3	3	3	4	4	4	5	5	5	5	5	7	7	7	7	7	7	7	7	7	4	4	4	4	4	3	3	3	3	3	1	1	1	1	1	1	1
Excavator - Backhoe/loader	3	3	5	7	7	7	7	7	7	7	7	3	3	3	3	3	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	3	3	3	3	2	2	2	0	0	0	0	0	0	0
Excavator - Earth Scraper 637	56	56	56	56	32	32	16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator - loader	4	4	4	4	4	4	4	4	4	4	4	4	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator - Motor Grader (CAT140H)	0	3	3	3	9	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	3	3	3	0	0	0	0	6	6	6	6	3	3	3	0	0	0	0	0	0	0
Excavator - Trencher (CAT320)	0	0	0	0	0	7	7	7	7	7	7	7	7	7	7	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fired Heaters (2,000 BTU)	0	0	0	0	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0
Forklift	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	4	4	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	1	1	1	1	1	1	1
Fusion Welder	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Heavy Haul / 600 tn Crane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	4	4	4	4	4	4	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Heavy Haul / 1,000 tn Crane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	4	4	4	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Light Plants	0	0	1	1	3	3	3	3	1	1	2	2	3	3	3	3	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	3	3	3	3	3	3	3	3	3	2	2	2	2	2	1	1	1	1
Man lifts - telescoping	0	0	0	0	0	0	0	0	5	5	5	9	9	9	9	9	9	9	9	14	14	14	14	19	19	19	19	19	19	19	19	19	19	19	19	14	14	14	9	9	9	9	5	5	5	5	2	2	2
Man lift - scissor	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Portable Compaction Roller	0	0	12	12	12	12	12	12	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	0	0	0	0	5	5	5	5	5	5	0	0	0	5	5	5	2	2	0	0	0	0	0	0	0
Portable Compaction - Vibratory Plate	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Portable Compaction - Ram	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pumps	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Portable Power Generators	8	8	8	8	12	12	12	12	12	20	20	20	20	20	20	31	31	31	31	31	31	31	41	41	41	41	41	41	41	41	41	41	41	41	41	31	31	31	31	20	20	20	20	20	20	10	10	10	4
Truck Crane - Greater than 300 ton	0	0	0	0	0	0	0	0	0	0	0	2	2	2	2	2	5	5	7	7	9	9	9	9	9	9	9	9	9	9	7	7	5	5	5	2	2	2	2	2	0	0	0	0	0	0	0	0	0
Truck Crane - Greater than 200 ton	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	3	3	3	4	4	4	4	4	4	4	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vibratory Roller Ingersol-Rand 20 ton	8	8	8	8	8	8	8	8	8	5	5	5	5	5	3	3	3	3	0	0	0	0	0	0	0	0	0	5	5	5	5	0	0	0	0	0	0	3	3	3	3	0	0	0	0	0	0	0	0
WORKER VEHICLES																																																	
Personal commuting vehicles	0	0	0	0	0	0	1	1	1	1	1	1	2	2	2	3	3	3	3	4	4	4	4	5	5	5	6	6	6	6	6	6	6	6	6	5	5	5	4	3	3	2	1	1	1	1	1	1	1
DELIVERY TRUCKS																																																	
Light delivery truck (e.g. Fed-Ex)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Heavy delivery truck (e.g. flat beds carrying construction eqp)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Import fill trucks	10	10	10	10	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ONSITE TOTAL (lbs/day)	**146**	**151**	**180**	**181**	**185**	**200**	**175**	**153**	**145**	**150**	**155**	**158**	**159**	**171**	**174**	**185**	**193**	**196**	**195**	**211**	**214**	**212**	**223**	**239**	**230**	**225**	**219**	**236**	**237**	**226**	**220**	**201**	**196**	**190**	**175**	**157**	**158**	**166**	**154**	**130**	**113**	**109**	**65**	**65**	**61**	**43**	**36**	**33**	**23**
OFF-SITE																																																	
WORKER VEHICLES																																																	
Personal commuting vehicles	7	12	16	20	30	38	45	60	67	80	100	112	132	155	187	211	230	244	257	272	286	320	344	370	393	398	437	468	483	486	491	484	479	458	433	420	381	369	313	255	202	137	110	109	109	101	86	79	59
DELIVERY TRUCKS																																																	
Light delivery truck (e.g. Fed-Ex)	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Heavy delivery truck (e.g. flat beds carrying construction eqp)	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Import fill trucks	47	47	47	47	47	47	47	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LINEARS																																																	
ON ROAD																																																	
Dump Truck	0	0	0	0	0	0	0	0	0	0	5	5	8	8	8	8	8	8	8	8	5	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Service Truck (MHD-DSL)	0	0	0	0	0	0	0	0	0	0	3	3	3	3	3	3	4	4	4	4	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pipe Haul Truck and Trailer (HHDT-DSL)	0	0	0	0	0	0	0	0	0	0	4	4	4	4	4	4	3	3	3	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3/4 Ton Pickup (MHD-DSL)	0	0	0	0	0	0	0	0	0	0	6	6	6	6	6	6	10	10	10	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck - water	0	0	0	0	0	0	0	0	0	0	3	3	5	5	5	5	5	5	5	5	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF ROAD																																																	
Air Compressor (185 CFM)	0	0	0	0	0	0	0	0	0	0	3	3	5	5	8	8	8	8	5	5	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bore Machine (Hydraulic)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 Ton Hydra Crane	0	0	0	0	0	0	0	0	0	0	3	5	5	8	8	8	8	8	8	8	5	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Backhoe/loader	0	0	0	0	0	0	0	0	0	0	10	10	16	16	16	16	16	16	16	16	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator - Trencher	0	0	0	0	0	0	0	0	0	0	0	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Forklift	0	0	0	0	0	0	0	0	0	0	1	1	2	2	2	2	2	2	2	2	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Welding Generator	0	0	0	0	0	0	0	0	0	0	16	16	16	16	16	16	16	16	16	16	16	16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 to 5 Ton AC Roller	0	0	0	0	0	0	0	0	0	0	0	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pipe Bending Machine	0	0	0	0	0	0	0	0	0	0	3	3	7	7	7	7	7	7	7	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL																																																	
AIR COMPRESSOR 185	0	0	0	0	0	0	0	0	0	0	0	0	0	3	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BOOM TRUCK 12 TON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT 325 BACKHOE	0	0	0	0	0	0	0	0	0	0	0	0	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT 330 BACKHOE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT DOZER D-6	0	0	0	0	0	0	0	0	0	0	0	0	9	9	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT MODEL 12 MOTOR GRADER	0	0	0	0	0	0	0	0	0	0	0	0	6	6	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT ROLLER-COMPACTOR 563	0	0	0	0	0	0	0	0	0	0	0	0	5	5	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT RUBBER TIRE LOADER 966	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT SCRAPER 615	0	0	0	0	0	0	0	0	0	0	0	0	8	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CRANE-ROUGH TERRAIN 45T	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENSET 5KW	0	0	0	0	0	0	0	0	0	0	0	0	0	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
JOHN DEERE TRACTOR 9400	0	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PICK-UP CRAFT	0	0	0	0	0	0	0	0	0	0	0	0	10	10	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PICK-UP OVERHEAD	0	0	0	0	0	0	0	0	0	0	0	0	7	22	22	18	18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL BALLAST REGULATOR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL CLIP MACHINE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL MOVER-SHUTTLE WAGON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL TAMPER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL WELDER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAMEX WALK BEHIND COMPACTOR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TRI-AXLE DUMP TRUCK	0	0	0	0	0	0	0	0	0	0	0	0	5	8	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TRUCK FLATBED 14 FOOT	0	0	0	0	0	0	0	0	0	0	0	0	1	1	4	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TRUCK TRACTOR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WATER TRUCK, 4M ON-ROAD	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WELDING MACHINE 350 AMP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LINEARS TOTAL (lbs/day)	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**56**	**65**	**143**	**162**	**155**	**151**	**155**	**94**	**91**	**86**	**69**	**65**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
OFFSITE VEHICLES TOTAL (lbs/day)	**69**	**74**	**78**	**83**	**92**	**100**	**107**	**75**	**82**	**96**	**115**	**127**	**148**	**170**	**202**	**226**	**246**	**260**	**273**	**288**	**301**	**335**	**359**	**385**	**408**	**413**	**453**	**484**	**499**	**501**	**506**	**499**	**495**	**473**	**449**	**435**	**397**	**384**	**329**	**270**	**217**	**153**	**125**	**125**	**125**	**117**	**101**	**94**	**75**
TOTAL PROJECT (lbs/day)	216	225	258	264	277	300	282	229	227	245	327	350	449	503	530	562	594	550	559	586	584	612	582	624	638	638	671	719	735	727	726	700	690	663	624	593	555	551	482	400	330	262	190	190	186	159	138	127	98

Notes:

1. According to schedules provided by Fluor, Linear construction (except rail) takes place in months 11-22.
2. According to schedules provided by Fluor, Rail construction occurs in months 13-17.

CO2

MONTHLY EMISSIONS (lbs/day)

CONSTRUCTION VEHICLES	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
ON-SITE																																																	
On-Road Vehicles																																																	
18 cy fill mat'l haul truck	0	0	2,861	2,861	5,722	5,722	5,722	5,722	2,861	2,861	2,861	2,861	1,431	1,431	1,431	1,431	1,431	1,431	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	858	858	858	858	286	286	286	0	0	0	0	0	0	0
Bus	572	572	572	572	858	858	858	858	858	858	1,431	1,431	1,431	1,431	1,431	1,431	2,003	2,003	2,003	2,861	2,861	2,861	2,861	4,006	4,006	4,006	4,006	4,006	4,006	4,006	4,006	4,006	4,006	4,006	4,006	3,433	3,433	3,433	2,861	2,861	1,431	1,431	858	858	572	572	572	286	286
Concrete Pumper Truck	0	0	0	0	0	572	572	572	572	572	572	572	572	858	858	858	572	572	572	572	572	0	0	0	0	0	0	286	286	286	286	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dump Truck	858	1,144	1,144	858	858	858	858	858	858	858	572	572	572	572	572	0	0	0	0	0	0	0	0	0	0	0	0	572	572	572	572	572	572	572	572	572	858	858	858	572	286	286	286	286	286	0	0	0	0
Diesel Tractor (Yard Dog)	0	0	0	0	0	649	649	649	649	649	649	1,298	1,298	1,298	1,298	1,298	2,596	2,596	2,596	2,596	2,596	2,596	2,596	3,245	3,245	3,245	3,245	3,245	3,245	3,245	3,245	3,245	3,245	3,245	3,245	1,298	1,298	1,298	1,298	1,298	1,298	1,298	0	0	0	0	0	0	0
Service Truck - 1 ton	572	572	572	1,144	1,144	1,144	1,144	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	286	286	286	286	286	286	286
Pile Driver Truck	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck - Fuel/Lube	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	136	136	136	136	136	136	136	0	0	0
Tractor Truck 5th Wheel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trucks - Pickup 3/4 ton	680	680	680	680	680	816	952	1,088	2,041	2,041	2,041	2,041	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	2,041	2,041	1,360	1,360	1,360	1,360	680
Trucks - 3 ton	286	286	286	286	286	572	572	572	1,144	1,144	1,144	1,144	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,144	858	858	858	858	572	572	572	286	286	286	286	0	0	0
Truck - Water	1,431	1,431	1,431	1,431	1,431	1,431	858	858	858	858	858	858	858	858	858	858	858	858	858	858	858	858	858	572	858	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	572	286	286	286	286	286	286	286
Off Road Vehicles																																																	
Air Compressor 185 CFM	214	214	214	214	320	320	320	320	320	320	320	320	320	641	641	641	854	854	854	1,068	1,068	1,068	1,068	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282	854	854	854	641	641	641	641	427	427	427	214	214	107	107
Air Compressor 750 CFM	0	0	0	0	225	225	225	225	450	450	450	450	450	450	450	901	901	901	901	901	901	901	901	901	901	901	901	901	901	450	450	450	450	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225
Articulating Boom Platform	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bob cat loader	0	0	168	168	168	168	168	672	672	672	672	672	504	504	504	504	504	504	336	336	336	336	336	336	0	0	0	0	0	0	0	0	0	0	0	168	168	168	168	168	168	168	0	0	0	0	0	0	0
Bulldozer D10R	4,584	4,584	4,584	3,056	3,056	3,056	3,056	3,056	3,056	1,528	1,528	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bulldozer D6C	1,164	1,164	1,164	1,164	776	776	776	776	776	776	388	388	388	388	388	0	0	0	0	0	0	0	0	0	0	0	0	388	388	388	388	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Concrete Trowel Machine	0	0	0	0	0	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	0	0	0	0	0	0	0	0	138	138	138	138	138	138	0	0	0	0	0	0	0
Concrete Vibrators	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cranes - Mobile 35 ton	0	0	0	0	0	0	215	215	215	862	862	862	862	1,508	1,508	1,508	1,508	1,508	1,508	1,508	1,508	1,508	1,508	1,508	1,508	1,508	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077	431	431	431	431	431	431	431	431	431	431	431	215	215	215	215
Cranes - Mobile 45 ton	0	0	0	0	0	0	0	0	0	0	690	690	690	690	690	690	690	690	1,381	1,381	1,381	1,381	1,381	1,381	1,381	1,381	1,381	1,381	1,381	690	690	690	690	690	690	690	690	690	690	690	345	345	0	0	0	0	0	0	0
Crane - Mobile 65 ton	0	0	0	0	0	0	0	0	0	0	0	345	345	690	1,381	1,726	1,726	1,726	2,071	2,071	2,071	2,071	2,071	2,071	2,071	2,071	2,071	2,071	2,071	2,071	1,726	1,726	1,381	690	690	690	690	690	345	345	345	345	345	345	345	0	0	0	0
Cranes 100 / 150 ton cap	0	0	0	0	0	0	0	0	0	0	482	482	964	964	1,446	1,446	1,927	1,927	1,927	1,927	1,927	1,927	1,927	1,927	1,927	1,927	1,927	1,927	964	964	482	482	482	482	482	482	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel Powered Welder	0	0	0	507	507	507	507	507	507	507	507	507	507	507	507	761	761	761	1,015	1,015	1,015	1,015	1,015	1,269	1,269	1,269	1,269	1,269	1,269	1,269	1,269	1,269	761	761	761	761	761	507	507	507	507	507	254	254	254	254	152	152	101
Excavator - Backhoe/loader	481	481	721	961	961	961	961	961	961	961	961	481	481	481	481	481	240	240	240	240	240	240	240	240	0	0	0	0	0	0	0	0	0	0	0	481	481	481	481	240	240	240	0	0	0	0	0	0	0
Excavator - Earth Scraper 637	14,837	14,837	14,837	14,837	8,478	8,478	4,239	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator - loader	636	636	636	636	636	636	636	636	636	636	636	636	318	318	0	0	0	0	0	0	0	0	0	0	0	0	0	318	318	318	318	0	0	0	0	0	0	318	318	318	0	0	0	0	0	0	0	0	0
Excavator - Motor Grader (CAT140H)	0	431	431	431	1,292	1,292	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	431	431	431	431	0	0	0	0	861	861	861	861	431	431	431	0	0	0	0	0	0	0
Excavator - Trencher (CAT320)	0	0	0	0	0	901	901	901	901	901	901	901	901	901	901	901	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fired Heaters (2,000 BTU)	0	0	0	0	327	327	327	327	246	246	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	246	246	246	164	164	164	164	164	164	164	164	164	164	164	82	82	82
Forklift	264	264	264	264	264	264	264	264	264	264	264	264	264	264	264	264	352	352	352	352	352	352	352	352	352	352	352	264	264	264	264	264	264	264	264	264	264	264	264	264	264	264	88	88	88	88	44	44	44
Fusion Welder	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Heavy Haul / 600 tn Crane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,302	1,302	1,302	1,302	1,302	1,302	1,302	1,302	1,302	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Heavy Haul / 1,000 tn Crane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,302	1,302	1,302	1,302	1,302	1,302	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Light Plants	82	82	164	327	655	655	655	655	327	327	491	491	655	655	819	819	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	819	819	819	819	819	819	819	819	819	409	409	409	409	409	327	327	164	164
Man lifts - telescoping	0	0	0	0	0	0	0	0	495	495	495	990	990	990	990	990	990	990	990	1,484	1,484	1,484	1,484	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,484	1,484	1,484	990	990	990	990	495	495	495	495	198	198	198
Man lift - scissor	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Portable Compaction Roller	0	0	1,694	1,694	1,694	1,694	1,694	1,694	678	678	678	678	678	678	678	678	678	678	678	678	678	678	678	678	0	0	0	0	678	678	678	678	678	678	0	0	0	678	678	678	339	339	0	0	0	0	0	0	0
Portable Compaction - Vibratory Plate	0	0	0	0	0	0	0	111	111	111	111	111	111	111	111	111	111	111	111	111	111	111	0	0	0	0	0	56	56	56	56	0	0	0	0	74	74	74	74	74	37	37	0	0	0	0	0	0	0
Portable Compaction - Ram	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pumps	246	246	246	491	491	491	491	491	491	491	491	491	491	491	491	491	491	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	164	164	164	164	164	164	164
Portable Power Generators	906	906	906	906	1,358	1,358	1,358	1,358	1,358	2,264	2,264	2,264	2,264	2,264	2,264	3,396	3,396	3,396	3,396	3,396	3,396	3,396	4,528	4,528	4,528	4,528	4,528	4,528	4,528	4,528	4,528	4,528	4,528	4,528	4,528	3,396	3,396	3,396	3,396	2,264	2,264	2,264	2,264	2,264	2,264	1,132	1,132	1,132	453
Truck Crane - Greater than 300 ton	0	0	0	0	0	0	0	0	0	0	0	774	774	774	774	774	1,547	1,547	2,321	2,321	3,095	3,095	3,095	3,095	3,095	3,095	3,095	3,095	3,095	2,321	2,321	1,547	1,547	1,547	774	774	774	774	774	0	0	0	0	0	0	0	0	0	0
Truck Crane - Greater than 200 ton	0	0	0	0	0	0	0	0	0	0	0	0	0	0	482	482	482	482	482	964	964	964	1,446	1,446	1,446	1,446	1,446	1,446	1,446	964	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vibratory Roller Ingersol-Rand 20 ton	1,394	1,394	1,394	1,394	1,394	1,394	1,394	1,394	1,394	929	929	929	929	929	465	465	465	465	0	0	0	0	0	0	0	0	0	929	929	929	929	0	0	0	0	0	0	465	465	465	465	0	0	0	0	0	0	0	0
WORKER VEHICLES																																																	
Personal commuting vehicles	15	25	34	44	65	82	98	131	146	175	218	243	288	338	407	460	502	533	561	594	623	697	749	806	857	867	954	1,021	1,054	1,060	1,071	1,055	1,045	998	945	915	832	805	683	555	440	299	239	238	238	221	187	171	129
DELIVERY TRUCKS																																																	
Light delivery truck (e.g. Fed-Ex)	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Heavy delivery truck (e.g. flat beds carrying construction eqp)	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424
Import fill trucks	2,035	2,035	2,035	2,035	2,035	2,035	2,035	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ONSITE TOTAL (lbs/day)	**31,956**	**32,684**	**37,738**	**37,663**	**36,386**	**39,086**	**33,350**	**27,289**	**25,261**	**24,850**	**26,290**	**26,569**	**27,276**	**28,924**	**30,028**	**31,302**	**33,671**	**34,758**	**34,786**	**38,170**	**38,973**	**38,475**	**40,030**	**42,556**	**41,639**	**40,061**	**38,414**	**41,373**	**40,983**	**38,592**	**36,812**	**33,288**	**32,262**	**31,299**	**28,576**	**26,047**	**25,906**	**27,086**	**25,338**	**21,353**	**18,073**	**17,467**	**10,114**	**10,113**	**9,147**	**6,855**	**5,875**	**5,303**	**3,850**
OFF-SITE																																																	
WORKER VEHICLES																																																	
Personal commuting vehicles	837	1,441	1,934	2,497	3,664	4,629	5,520	7,415	8,245	9,927	12,310	13,762	16,308	19,127	23,026	26,019	28,397	30,137	31,729	33,615	35,250	39,447	42,401	45,600	48,495	49,067	53,947	57,764	59,641	59,975	60,565	59,688	59,142	56,484	53,466	51,785	47,061	45,535	38,644	31,407	24,884	16,929	13,513	13,488	13,488	12,479	10,584	9,698	7,310
DELIVERY TRUCKS																																																	
Light delivery truck (e.g. Fed-Ex)	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457
Heavy delivery truck (e.g. flat beds carrying construction eqp)	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182	7,182
Import fill trucks	22,688	22,688	22,688	22,688	22,688	22,688	22,688	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LINEARS																																																	
ON ROAD																																																	
Dump Truck	0	0	0	0	0	0	0	0	0	0	1,144	1,144	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,144	1,144	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Service Truck (MHD-DSL)	0	0	0	0	0	0	0	0	0	0	572	572	572	572	572	572	858	858	858	858	858	858	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pipe Haul Truck and Trailer (HHDT-DSL)	0	0	0	0	0	0	0	0	0	0	858	858	858	858	858	858	572	572	572	572	572	572	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3/4 Ton Pickup (MHD-DSL)	0	0	0	0	0	0	0	0	0	0	1,360	1,360	1,360	1,360	1,360	1,360	2,041	2,041	2,041	2,041	2,041	2,041	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck - water	0	0	0	0	0	0	0	0	0	0	572	572	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144	572	572	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF ROAD																																																	
Air Compressor (185 CFM)	0	0	0	0	0	0	0	0	0	0	214	214	427	427	641	641	641	641	427	427	214	214	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bore Machine (Hydraulic)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	233	233	233	233	233	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 Ton Hydra Crane	0	0	0	0	0	0	0	0	0	0	964	1,927	1,927	2,891	2,891	2,891	2,891	2,891	2,891	2,891	1,927	1,927	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Backhoe/loader	0	0	0	0	0	0	0	0	0	0	1,442	1,442	2,403	2,403	2,403	2,403	2,403	2,403	2,403	2,403	1,442	1,442	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator - Trencher	0	0	0	0	0	0	0	0	0	0	0	427	427	427	427	427	427	427	427	427	427	427	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Forklift	0	0	0	0	0	0	0	0	0	0	88	88	176	176	176	176	176	176	176	176	176	88	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Welding Generator	0	0	0	0	0	0	0	0	0	0	1,811	1,811	1,811	1,811	1,811	1,811	1,811	1,811	1,811	1,811	1,811	1,811	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 to 5 Ton AC Roller	0	0	0	0	0	0	0	0	0	0	0	299	299	299	299	299	299	299	299	299	299	299	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pipe Bending Machine	0	0	0	0	0	0	0	0	0	0	347	347	694	694	694	694	694	694	694	347	347	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL																																																	
AIR COMPRESSOR 185	0	0	0	0	0	0	0	0	0	0	0	0	0	214	214	214	214	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BOOM TRUCK 12 TON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	286	286	286	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT 325 BACKHOE	0	0	0	0	0	0	0	0	0	0	0	0	471	471	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT 330 BACKHOE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	798	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT DOZER D-6	0	0	0	0	0	0	0	0	0	0	0	0	1,429	1,429	0	0	714	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT MODEL 12 MOTOR GRADER	0	0	0	0	0	0	0	0	0	0	0	0	861	861	431	431	431	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT ROLLER-COMPACTOR 563	0	0	0	0	0	0	0	0	0	0	0	0	678	678	339	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT RUBBER TIRE LOADER 966	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,608	1,608	1,608	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT SCRAPER 615	0	0	0	0	0	0	0	0	0	0	0	0	2,763	1,381	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CRANE-ROUGH TERRAIN 45T	0	0	0	0	0	0	0	0	0	0	0	0	0	345	345	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENSET 5KW	0	0	0	0	0	0	0	0	0	0	0	0	0	302	151	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
JOHN DEERE TRACTOR 9400	0	0	0	0	0	0	0	0	0	0	0	0	1,602	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PICK-UP CRAFT	0	0	0	0	0	0	0	0	0	0	0	0	4,725	4,725	4,725	4,725	4,725	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PICK-UP OVERHEAD	0	0	0	0	0	0	0	0	0	0	0	0	1,320	3,959	3,959	3,299	3,299	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL BALLAST REGULATOR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	660	660	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL CLIP MACHINE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	173	173	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL MOVER-SHUTTLE WAGON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	660	660	660	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL TAMPER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	660	660	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL WELDER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	101	51	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAMEX WALK BEHIND COMPACTOR	0	0	0	0	0	0	0	0	0	0	0	0	0	19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TRI-AXLE DUMP TRUCK	0	0	0	0	0	0	0	0	0	0	0	0	1,144	1,717	572	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TRUCK FLATBED 14 FOOT	0	0	0	0	0	0	0	0	0	0	0	0	286	286	858	858	858	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TRUCK TRACTOR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,116	1,116	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WATER TRUCK, 4M ON-ROAD	0	0	0	0	0	0	0	0	0	0	0	0	286	286	286	286	286	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WELDING MACHINE 350 AMP	0	0	0	0	0	0	0	0	0	0	0	0	51	51	51	51	51	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LINEARS TOTAL (lbs/day)	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**9,373**	**11,062**	**29,431**	**31,502**	**31,623**	**30,352**	**30,581**	**15,906**	**15,692**	**15,113**	**11,830**	**11,395**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
OFFSITE VEHICLES TOTAL (lbs/day)	**31,164**	**31,769**	**32,261**	**32,824**	**33,991**	**34,956**	**35,847**	**15,054**	**15,884**	**17,567**	**19,949**	**21,401**	**23,947**	**26,766**	**30,665**	**33,658**	**36,036**	**37,776**	**39,368**	**41,255**	**42,889**	**47,086**	**50,040**	**53,240**	**56,134**	**56,706**	**61,586**	**65,403**	**67,281**	**67,614**	**68,204**	**67,327**	**66,781**	**64,123**	**61,105**	**59,424**	**54,701**	**53,174**	**46,283**	**39,046**	**32,524**	**24,568**	**21,152**	**21,127**	**21,127**	**20,118**	**18,223**	**17,337**	**14,949**
TOTAL PROJECT (lbs/day)	63,121	64,452	69,999	70,487	70,377	74,042	69,197	42,343	41,144	42,416	55,611	59,032	80,654	87,192	92,316	95,312	100,288	88,441	89,847	94,538	93,692	96,956	90,069	95,795	97,773	96,767	100,000	106,777	108,263	106,206	105,016	100,615	99,043	95,422	89,681	85,471	80,607	80,260	71,621	60,399	50,596	42,036	31,266	31,241	30,274	26,973	24,098	22,640	18,800

Notes:

1. According to schedules provided by Fluor, Linear construction (except rail) takes place in months 11-22.
2. According to schedules provided by Fluor, Rail construction occurs in months 13-17.

Hydrogen Energy California, Kern County Power Project
Methane (CH4) Emissions by Month
8/14/2012

CH4	MONTHLY EMISSIONS (lbs/day)																																																
CONSTRUCTION VEHICLES	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
ON-SITE																																																	
On-Road Vehicles																																																	
18 cy fill mat'l haul truck	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bus	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Concrete Pumper Truck	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dump Truck	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Diesel Tractor (Yard Dog)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Service Truck - 1 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pile Driver Truck	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck - Fuel/Lube	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tractor Truck 5th Wheel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trucks - Pickup 3/4 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trucks - 3 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck - Water	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Off Road Vehicles																																																	
Air Compressor 185 CFM	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.1	0.1	0.0	0.0
Air Compressor 750 CFM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Articulating Boom Platform	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bob cat loader	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bulldozer D10R	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bulldozer D6C	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Concrete Trowel Machine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Concrete Vibrators	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cranes - Mobile 35 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0
Cranes - Mobile 45 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Crane - Mobile 65 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cranes 100 / 150 ton cap	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Diesel Powered Welder	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Backhoe/loader	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Earth Scraper 637	1.3	1.3	1.3	1.3	0.8	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - loader	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Motor Grader (CAT140H)	0.0	0.1	0.1	0.1	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Trencher (CAT320)	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fired Heaters (2,000 BTU)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Forklift	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fusion Welder	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Haul / 600 tn Crane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Haul / 1,000 tn Crane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Light Plants	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Man lifts - telescoping	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Man lift - scissor	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Compaction Roller	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Compaction - Vibratory Plate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Compaction - Ram	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumps	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Power Generators	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.6	0.6	0.6	0.6	0.6	0.6	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.0	1.0	1.0	1.0	0.6	0.6	0.6	0.6	0.6	0.6	0.3	0.3	0.3	0.1
Truck Crane - Greater than 300 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck Crane - Greater than 200 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Vibratory Roller Ingersol-Rand 20 ton	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WORKER VEHICLES																																																	
Personal commuting vehicles	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DELIVERY TRUCKS																																																	
Light delivery truck (e.g. Fed-Ex)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Heavy delivery truck (e.g. flat beds carrying construction eqp)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Import fill trucks	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ONSITE TOTAL (lbs/day)	**2.8**	**2.9**	**3.3**	**3.3**	**3.2**	**3.4**	**2.9**	**2.6**	**2.6**	**2.8**	**2.9**	**2.9**	**2.9**	**3.2**	**3.2**	**3.7**	**3.7**	**3.8**	**3.9**	**4.3**	**4.4**	**4.4**	**4.7**	**5.0**	**4.8**	**4.7**	**4.5**	**4.8**	**4.8**	**4.5**	**4.4**	**4.0**	**3.8**	**3.7**	**3.4**	**3.0**	**3.0**	**3.1**	**2.8**	**2.3**	**2.1**	**2.1**	**1.4**	**1.4**	**1.3**	**0.8**	**0.7**	**0.6**	**0.4**
OFF-SITE																																																	
WORKER VEHICLES																																																	
Personal commuting vehicles	0.2	0.3	0.5	0.6	0.9	1.1	1.3	1.7	1.9	2.3	2.9	3.2	3.8	4.5	5.4	6.1	6.7	7.1	7.5	7.9	8.3	9.3	10.0	10.7	11.4	11.6	12.7	13.6	14.1	14.1	14.3	14.1	13.9	13.3	12.6	12.2	11.1	10.7	9.1	7.4	5.9	4.0	3.2	3.2	3.2	2.9	2.5	2.3	1.7
DELIVERY TRUCKS																																																	
Light delivery truck (e.g. Fed-Ex)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy delivery truck (e.g. flat beds carrying construction eqp)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Import fill trucks	1.1	1.1	1.1	1.1	1.1	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LINEARS																																																	
ON ROAD																																																	
Dump Truck	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Service Truck (MHD-DSL)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipe Haul Truck and Trailer (HHDT-DSL)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3/4 Ton Pickup (MHD-DSL)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck - water	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OFF ROAD																																																	
Air Compressor (185 CFM)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bore Machine (Hydraulic)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12 Ton Hydra Crane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Backhoe/loader	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Trencher	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Forklift	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Welding Generator	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3 to 5 Ton AC Roller	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipe Bending Machine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL																																																	
AIR COMPRESSOR 185	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BOOM TRUCK 12 TON	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT 325 BACKHOE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT 330 BACKHOE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT DOZER D-6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT MODEL 12 MOTOR GRADER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT ROLLER-COMPACTOR 563	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT RUBBER TIRE LOADER 966	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT SCRAPER 615	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CRANE-ROUGH TERRAIN 45T	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GENSET 5KW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
JOHN DEERE TRACTOR 9400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PICK-UP CRAFT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PICK-UP OVERHEAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL BALLAST REGULATOR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL CLIP MACHINE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL MOVER-SHUTTLE WAGON	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL TAMPER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL WELDER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAMEX WALK BEHIND COMPACTOR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRI-AXLE DUMP TRUCK	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRUCK FLATBED 14 FOOT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRUCK TRACTOR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WATER TRUCK, 4M ON-ROAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WELDING MACHINE 350 AMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LINEARS TOTAL (lbs/day)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**1.1**	**1.4**	**2.9**	**3.2**	**3.1**	**3.0**	**3.1**	**1.9**	**1.8**	**1.7**	**1.4**	**1.3**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
OFFSITE VEHICLES TOTAL (lbs/day)	**1.6**	**1.8**	**1.9**	**2.0**	**2.3**	**2.5**	**2.7**	**2.1**	**2.3**	**2.7**	**3.3**	**3.6**	**4.2**	**4.9**	**5.8**	**6.5**	**7.0**	**7.5**	**7.8**	**8.3**	**8.7**	**9.7**	**10.3**	**11.1**	**11.8**	**11.9**	**13.1**	**14.0**	**14.4**	**14.5**	**14.6**	**14.4**	**14.3**	**13.7**	**13.0**	**12.6**	**11.4**	**11.1**	**9.5**	**7.8**	**6.2**	**4.3**	**3.5**	**3.5**	**3.5**	**3.3**	**2.8**	**2.6**	**2.1**
TOTAL PROJECT (lbs/day)	4.5	4.7	5.2	5.4	5.5	5.9	5.6	4.7	4.9	5.4	7.2	7.9	10.0	11.2	12.1	13.2	13.8	13.2	13.6	14.3	14.5	15.3	15.1	16.1	16.6	16.6	17.6	18.8	19.2	19.0	19.0	18.4	18.1	17.4	16.4	15.6	14.4	14.2	12.3	10.1	8.3	6.4	4.9	4.9	4.9	4.1	3.5	3.3	2.5

Notes:

1. According to schedules provided by Fluor, Linear construction (except rail) takes place in months 11-22.
2. According to schedules provided by Fluor, Rail construction occurs in months 13-17.

Hydrogen Energy California, Kern County Power Project
Nitrous Oxide (N2O) Emissions by Month
8/14/2012

N2O

MONTHLY EMISSIONS (lbs/day)

	CONSTRUCTION VEHICLES	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
ON-SITE	**On-Road Vehicles**																																																	
	18 cy fill mat'l haul truck	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Bus	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Concrete Pumper Truck	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Dump Truck	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Diesel Tractor (Yard Dog)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Service Truck - 1 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Pile Driver Truck	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Truck - Fuel/Lube	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Tractor Truck 5th Wheel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Trucks - Pickup 3/4 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Trucks - 3 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Truck - Water	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Off Road Vehicles																																																	
	Air Compressor 185 CFM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Air Compressor 750 CFM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Articulating Boom Platform	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Bob cat loader	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Bulldozer D10R	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Bulldozer D6C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Concrete Trowel Machine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Concrete Vibrators	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Cranes - Mobile 35 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Cranes - Mobile 45 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Crane - Mobile 65 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Cranes 100 / 150 ton cap	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Diesel Powered Welder	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Excavator - Backhoe/loader	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Excavator - Earth Scraper 637	0.3	0.3	0.3	0.3	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Excavator - loader	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Excavator - Motor Grader (CAT140H)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Excavator - Trencher (CAT320)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Fired Heaters (2,000 BTU)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Forklift	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Fusion Welder	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Heavy Haul / 600 tn Crane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Heavy Haul / 1,000 tn Crane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Light Plants	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Man lifts - telescoping	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Man lift - scissor	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Portable Compaction Roller	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Portable Compaction - Vibratory Plate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Portable Compaction - Ram	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Pumps	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Portable Power Generators	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Truck Crane - Greater than 300 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Truck Crane - Greater than 200 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Vibratory Roller Ingersol-Rand 20 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	WORKER VEHICLES																																																	
	Personal commuting vehicles	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00
	DELIVERY TRUCKS																																																	
	Light delivery truck (e.g. Fed-Ex)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Heavy delivery truck (e.g. flat beds carrying construction eqp)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	Import fill trucks	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	ONSITE TOTAL (lbs/day)	**0.6**	**0.6**	**0.7**	**0.7**	**0.7**	**0.7**	**0.6**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.6**	**0.6**	**0.6**	**0.7**	**0.7**	**0.8**	**0.8**	**0.9**	**0.9**	**0.9**	**0.9**	**1.0**	**0.9**	**0.9**	**0.9**	**0.9**	**0.9**	**0.8**	**0.8**	**0.7**	**0.7**	**0.7**	**0.6**	**0.5**	**0.5**	**0.6**	**0.5**	**0.4**	**0.4**	**0.4**	**0.2**	**0.2**	**0.2**	**0.1**	**0.1**	**0.1**	**0.1**
OFF-SITE	**WORKER VEHICLES**																																																	
	Personal commuting vehicles	0.10	0.17	0.23	0.30	0.44	0.55	0.66	0.88	0.98	1.18	1.46	1.63	1.94	2.27	2.73	3.09	3.37	3.58	3.77	3.99	4.19	4.68	5.04	5.42	5.76	5.83	6.41	6.86	7.08	7.12	7.19	7.09	7.02	6.71	6.35	6.15	5.59	5.41	4.59	3.73	2.96	2.01	1.60	1.60	1.60	1.48	1.26	1.15	0.87
	DELIVERY TRUCKS																																																	
	Light delivery truck (e.g. Fed-Ex)	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	Heavy delivery truck (e.g. flat beds carrying construction eqp)	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
	Import fill trucks	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	LINEARS																																																	
	ON ROAD																																																	
	Dump Truck	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Service Truck (MHD-DSL)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Pipe Haul Truck and Trailer (HHDT-DSL)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	3/4 Ton Pickup (MHD-DSL)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Truck - water	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	OFF ROAD																																																	
	Air Compressor (185 CFM)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Bore Machine (Hydraulic)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	12 Ton Hydra Crane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Backhoe/loader	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Excavator - Trencher	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Forklift	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Welding Generator	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	3 to 5 Ton AC Roller	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Pipe Bending Machine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RAIL																																																	
	AIR COMPRESSOR 185	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	BOOM TRUCK 12 TON	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	CAT 325 BACKHOE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	CAT 330 BACKHOE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	CAT DOZER D-6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	CAT MODEL 12 MOTOR GRADER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	CAT ROLLER-COMPACTOR 563	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	CAT RUBBER TIRE LOADER 966	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	CAT SCRAPER 615	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	CRANE-ROUGH TERRAIN 45T	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	GENSET 5KW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	JOHN DEERE TRACTOR 9400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	PICK-UP CRAFT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	PICK-UP OVERHEAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RAIL BALLAST REGULATOR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RAIL CLIP MACHINE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RAIL MOVER-SHUTTLE WAGON	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RAIL TAMPER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RAIL WELDER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RAMEX WALK BEHIND COMPACTOR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	TRI-AXLE DUMP TRUCK	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	TRUCK FLATBED 14 FOOT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	TRUCK TRACTOR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	WATER TRUCK, 4M ON-ROAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	WELDING MACHINE 350 AMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	LINEARS TOTAL (lbs/day)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.2**	**0.2**	**0.3**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.3**	**0.3**	**0.3**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
	OFFSITE VEHICLES TOTAL (lbs/day)	**1.0**	**1.1**	**1.1**	**1.2**	**1.4**	**1.5**	**1.6**	**1.1**	**1.2**	**1.4**	**1.7**	**1.9**	**2.2**	**2.5**	**3.0**	**3.3**	**3.6**	**3.8**	**4.0**	**4.2**	**4.4**	**4.9**	**5.3**	**5.7**	**6.0**	**6.1**	**6.6**	**7.1**	**7.3**	**7.4**	**7.4**	**7.3**	**7.3**	**6.9**	**6.6**	**6.4**	**5.8**	**5.6**	**4.8**	**4.0**	**3.2**	**2.3**	**1.8**	**1.8**	**1.8**	**1.7**	**1.5**	**1.4**	**1.1**
	TOTAL PROJECT (lbs/day)	1.6	1.7	1.8	1.9	2.0	2.2	2.2	1.7	1.7	1.9	2.4	2.7	3.1	3.5	4.0	4.4	4.7	4.9	5.1	5.4	5.6	6.1	6.2	6.6	6.9	7.0	7.5	8.0	8.2	8.2	8.2	8.0	8.0	7.6	7.2	6.9	6.4	6.2	5.4	4.4	3.6	2.6	2.1	2.1	2.0	1.9	1.6	1.5	1.2

Notes:

1. According to schedules provided by Fluor, Linear construction (except rail) takes place in months 11-22.
2. According to schedules provided by Fluor, Rail construction occurs in months 13-17.

Hydrogen Energy California, Kern County Power Project
Nitrogen Oxides (NOx) Emissions by Month
8/14/2012

MONTHLY EMISSIONS (lbs/day)

NOx	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
ON-SITE																																																	
CONSTRUCTION VEHICLES																																																	
On-Road Vehicles																																																	
18 cy fill mat'l haul truck	0	0	28	28	57	57	57	57	28	28	28	28	14	14	14	14	14	14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9	9	9	9	3	3	3	0	0	0	0	0	0	0
Bus	6	6	6	6	9	9	9	9	9	9	14	14	14	14	14	14	20	20	20	28	28	28	28	40	40	40	40	40	40	40	40	40	40	40	40	34	34	34	28	28	14	14	9	9	6	6	6	3	3
Concrete Pumper Truck	0	0	0	0	0	6	6	6	6	6	6	6	6	9	9	9	6	6	6	6	6	0	0	0	0	0	0	3	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dump Truck	9	11	11	9	9	9	9	9	9	9	6	6	6	6	6	0	0	0	0	0	0	0	0	0	0	0	0	6	6	6	6	6	6	6	6	6	9	9	9	6	3	3	3	3	3	0	0	0	0
Diesel Tractor (Yard Dog)	0	0	0	0	0	6	6	6	6	6	6	13	13	13	13	13	26	26	26	26	26	26	26	32	32	32	32	32	32	32	32	32	32	32	32	13	13	13	13	13	13	13	0	0	0	0	0	0	0
Service Truck - 1 ton	6	6	6	11	11	11	11	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	3	3	3	3	3	3	3
Pile Driver Truck	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck - Fuel/Lube	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	0	0	0
Tractor Truck 5th Wheel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trucks - Pickup 3/4 ton	6	6	6	6	6	7	8	9	17	17	17	17	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	17	17	11	11	11	11	6
Trucks - 3 ton	3	3	3	3	3	6	6	6	11	11	11	11	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	11	9	9	9	9	6	6	6	3	3	3	3	0	0	0
Truck - Water	14	14	14	14	14	14	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	6	9	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	3	3	3	3	3	3	3
Off Road Vehicles																																																	
Air Compressor 185 CFM	2	2	2	2	3	3	3	3	3	3	3	3	3	7	7	7	9	9	9	11	11	11	11	13	13	13	13	13	13	13	13	13	13	13	13	9	9	9	7	7	7	7	4	4	4	2	2	1	1
Air Compressor 750 CFM	0	0	0	0	3	3	3	3	5	5	5	5	5	5	5	10	10	10	10	10	10	10	10	10	10	10	10	10	10	5	5	5	5	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Articulating Boom Platform	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bob cat loader	0	0	2	2	2	2	2	7	7	7	7	7	5	5	5	5	5	5	3	3	3	3	3	3	0	0	0	0	0	0	0	0	0	0	0	2	2	2	2	2	2	2	0	0	0	0	0	0	0
Bulldozer D10R	40	40	40	26	26	26	26	26	26	13	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bulldozer D6C	14	14	14	14	9	9	9	9	9	9	5	5	5	5	5	0	0	0	0	0	0	0	0	0	0	0	0	5	5	5	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Concrete Trowel Machine	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	1	1	1	1	1	1	0	0	0	0	0	0	0
Concrete Vibrators	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cranes - Mobile 35 ton	0	0	0	0	0	0	2	2	2	9	9	9	9	17	17	17	17	17	17	17	17	17	17	17	17	17	12	12	12	12	12	12	12	12	5	5	5	5	5	5	5	5	5	5	5	2	2	2	2
Cranes - Mobile 45 ton	0	0	0	0	0	0	0	0	0	0	7	7	7	7	7	7	7	7	13	13	13	13	13	13	13	13	13	13	13	7	7	7	7	7	7	7	7	7	7	7	3	3	0	0	0	0	0	0	0
Crane - Mobile 65 ton	0	0	0	0	0	0	0	0	0	0	0	3	3	7	13	17	17	17	20	20	20	20	20	20	20	20	20	20	20	20	17	17	13	7	7	7	7	7	3	3	3	3	3	3	3	0	0	0	0
Cranes 100 / 150 ton cap	0	0	0	0	0	0	0	0	0	0	4	4	9	9	13	13	17	17	17	17	17	17	17	17	17	17	17	17	9	9	4	4	4	4	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel Powered Welder	0	0	0	5	5	5	5	5	5	5	5	5	5	5	5	7	7	7	9	9	9	9	9	12	12	12	12	12	12	12	12	12	7	7	7	7	7	5	5	5	5	5	2	2	2	2	1	1	1
Excavator - Backhoe/loader	4	4	6	8	8	8	8	8	8	8	8	4	4	4	4	4	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	4	4	4	4	2	2	2	0	0	0	0	0	0	0
Excavator - Earth Scraper 637	131	131	131	131	75	75	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator - loader	6	6	6	6	6	6	6	6	6	6	6	6	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	3	3	3	3	0	0	0	0	0	0	3	3	3	0	0	0	0	0	0	0	0	0
Excavator - Motor Grader (CAT140H)	0	4	4	4	13	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	4	4	4	0	0	0	0	9	9	9	9	4	4	4	0	0	0	0	0	0	0
Excavator - Trencher (CAT320)	0	0	0	0	0	11	11	11	11	11	11	11	11	11	11	11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fired Heaters (2,000 BTU)	0	0	0	0	3	3	3	3	2	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Forklift	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	1	1	1	1	0	0	0
Fusion Welder	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Heavy Haul / 600 tn Crane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	11	11	11	11	11	11	11	11	11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Heavy Haul / 1,000 tn Crane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	11	11	11	11	11	11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Light Plants	1	1	1	3	5	5	5	5	3	3	4	4	5	5	6	6	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	6	6	6	6	6	6	6	6	6	3	3	3	3	3	3	3	1	1
Man lifts - telescoping	0	0	0	0	0	0	0	0	5	5	5	9	9	9	9	9	9	9	9	14	14	14	14	19	19	19	19	19	19	19	19	19	19	19	19	14	14	14	9	9	9	9	5	5	5	5	2	2	2
Man lift - scissor	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Portable Compaction Roller	0	0	18	18	18	18	18	18	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	0	0	0	0	7	7	7	7	7	7	0	0	0	7	7	7	4	4	0	0	0	0	0	0	0
Portable Compaction - Vibratory Plate	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0
Portable Compaction - Ram	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pumps	2	2	2	4	4	4	4	4	4	4	4	4	4	4	4	4	4	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1
Portable Power Generators	9	9	9	9	13	13	13	13	13	22	22	22	22	22	22	32	32	32	32	32	32	32	43	43	43	43	43	43	43	43	43	43	43	43	43	32	32	32	32	22	22	22	22	22	22	11	11	11	4
Truck Crane - Greater than 300 ton	0	0	0	0	0	0	0	0	0	0	0	6	6	6	6	6	12	12	18	18	24	24	24	24	24	24	24	24	24	18	18	12	12	12	6	6	6	6	6	0	0	0	0	0	0	0	0	0	0
Truck Crane - Greater than 200 ton	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	4	4	4	4	9	9	9	13	13	13	13	13	13	13	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vibratory Roller Ingersol-Rand 20 ton	13	13	13	13	13	13	13	13	13	9	9	9	9	9	4	4	4	4	0	0	0	0	0	0	0	0	0	9	9	9	9	0	0	0	0	0	0	4	4	4	4	0	0	0	0	0	0	0	0
WORKER VEHICLES																																																	
Personal commuting vehicles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.3	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
DELIVERY TRUCKS																																																	
Light delivery truck (e.g. Fed-Ex)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Heavy delivery truck (e.g. flat beds carrying construction eqp)	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Import fill trucks	24.2	24.2	24.2	24.2	24.2	24.2	24.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ONSITE TOTAL (lbs/day)	**298**	**305**	**356**	**355**	**348**	**376**	**324**	**263**	**242**	**240**	**252**	**255**	**259**	**275**	**284**	**296**	**314**	**323**	**321**	**351**	**358**	**352**	**366**	**390**	**381**	**367**	**352**	**381**	**378**	**356**	**340**	**307**	**298**	**289**	**263**	**238**	**238**	**250**	**234**	**198**	**168**	**163**	**94**	**94**	**85**	**63**	**54**	**49**	**36**
OFF-SITE																																																	
WORKER VEHICLES																																																	
Personal commuting vehicles	0.8	1.4	1.9	2.4	3.6	4.5	5.4	7.2	8.0	9.6	11.9	13.4	15.8	18.6	22.3	25.2	27.6	29.2	30.8	32.6	34.2	38.3	41.1	44.2	47.1	47.6	52.3	56.0	57.9	58.2	58.8	57.9	57.4	54.8	51.9	50.2	45.7	44.2	37.5	30.5	24.1	16.4	13.1	13.1	13.1	12.1	10.3	9.4	7.1
DELIVERY TRUCKS																																																	
Light delivery truck (e.g. Fed-Ex)	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Heavy delivery truck (e.g. flat beds carrying construction eqp)	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6
Import fill trucks	232.4	232.4	232.4	232.4	232.4	232.4	232.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LINEARS																																																	
ON ROAD																																																	
Dump Truck	0	0	0	0	0	0	0	0	0	0	11	11	17	17	17	17	17	17	17	17	11	11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Service Truck (MHD-DSL)	0	0	0	0	0	0	0	0	0	0	6	6	6	6	6	6	9	9	9	9	9	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pipe Haul Truck and Trailer (HHDT-DSL)	0	0	0	0	0	0	0	0	0	0	9	9	9	9	9	9	6	6	6	6	6	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3/4 Ton Pickup (MHD-DSL)	0	0	0	0	0	0	0	0	0	0	11	11	11	11	11	11	17	17	17	17	17	17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck - water	0	0	0	0	0	0	0	0	0	0	6	6	11	11	11	11	11	11	11	11	6	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF ROAD																																																	
Air Compressor (185 CFM)	0	0	0	0	0	0	0	0	0	0	2	2	4	4	7	7	7	7	4	4	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bore Machine (Hydraulic)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 Ton Hydra Crane	0	0	0	0	0	0	0	0	0	0	9	17	17	26	26	26	26	26	26	26	17	17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Backhoe/loader	0	0	0	0	0	0	0	0	0	0	13	13	21	21	21	21	21	21	21	21	13	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator - Trencher	0	0	0	0	0	0	0	0	0	0	0	4	4	4	4	4	4	4	4	4	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Forklift	0	0	0	0	0	0	0	0	0	0	1	1	2	2	2	2	2	2	2	2	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Welding Generator	0	0	0	0	0	0	0	0	0	0	17	17	17	17	17	17	17	17	17	17	17	17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 to 5 Ton AC Roller	0	0	0	0	0	0	0	0	0	0	0	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pipe Bending Machine	0	0	0	0	0	0	0	0	0	0	3	3	6	6	6	6	6	6	6	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL																																																	
AIR COMPRESSOR 185	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BOOM TRUCK 12 TON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT 325 BACKHOE	0	0	0	0	0	0	0	0	0	0	0	0	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT 330 BACKHOE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT DOZER D-6	0	0	0	0	0	0	0	0	0	0	0	0	15	15	0	0	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT MODEL 12 MOTOR GRADER	0	0	0	0	0	0	0	0	0	0	0	0	9	9	4	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT ROLLER-COMPACTOR 563	0	0	0	0	0	0	0	0	0	0	0	0	7	7	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT RUBBER TIRE LOADER 966	0	0	0	0	0	0	0	0	0	0	0	0	0	0	13	13	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT SCRAPER 615	0	0	0	0	0	0	0	0	0	0	0	0	27	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CRANE-ROUGH TERRAIN 45T	0	0	0	0	0	0	0	0	0	0	0	0	0	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENSET 5KW	0	0	0	0	0	0	0	0	0	0	0	0	0	3	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
JOHN DEERE TRACTOR 9400	0	0	0	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PICK-UP CRAFT	0	0	0	0	0	0	0	0	0	0	0	0	28	28	28	28	28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PICK-UP OVERHEAD	0	0	0	0	0	0	0	0	0	0	0	0	10	30	30	25	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL BALLAST REGULATOR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL CLIP MACHINE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL MOVER-SHUTTLE WAGON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	5	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL TAMPER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL WELDER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAMEX WALK BEHIND COMPACTOR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TRI-AXLE DUMP TRUCK	0	0	0	0	0	0	0	0	0	0	0	0	11	17	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TRUCK FLATBED 14 FOOT	0	0	0	0	0	0	0	0	0	0	0	0	3	3	9	9	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TRUCK TRACTOR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WATER TRUCK, 4M ON-ROAD	0	0	0	0	0	0	0	0	0	0	0	0	3	3	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WELDING MACHINE 350 AMP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LINEARS TOTAL (lbs/day)	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**87**	**103**	**256**	**275**	**266**	**254**	**259**	**147**	**145**	**140**	**109**	**105**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
OFFSITE VEHICLES TOTAL (lbs/day)	**311**	**312**	**312**	**313**	**314**	**315**	**316**	**85**	**86**	**88**	**90**	**92**	**94**	**97**	**101**	**103**	**106**	**107**	**109**	**111**	**112**	**116**	**119**	**122**	**125**	**126**	**131**	**134**	**136**	**136**	**137**	**136**	**136**	**133**	**130**	**128**	**124**	**122**	**116**	**109**	**102**	**95**	**91**	**91**	**91**	**90**	**88**	**88**	**85**
TOTAL PROJECT (lbs/day)	609	617	668	668	662	691	640	349	328	328	430	450	608	647	651	653	679	578	575	602	579	574	485	513	506	493	483	515	514	493	477	443	434	422	393	367	362	373	350	307	270	258	185	185	176	153	142	136	121

Notes:

1. According to schedules provided by Fluor, Linear construction (except rail) takes place in months 11-22.
2. According to schedules provided by Fluor, Rail construction occurs in months 13-17.

PM10 - Combustion

MONTHLY EMISSIONS (lbs/day)

CONSTRUCTION VEHICLES	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
ON-SITE																									
On-Road Vehicles																									
18 cy fill mat'l haul truck	0.00	0.00	1.77	1.77	3.53	3.53	3.53	3.53	1.77	1.77	1.77	1.77	0.88	0.88	0.88	0.88	0.88	0.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bus	0.35	0.35	0.35	0.35	0.53	0.53	0.53	0.53	0.53	0.53	0.88	0.88	0.88	0.88	0.88	0.88	1.24	1.24	1.24	1.77	1.77	1.77	1.77	2.47	2.47
Concrete Pumper Truck	0.00	0.00	0.00	0.00	0.00	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.53	0.53	0.53	0.35	0.35	0.35	0.35	0.35	0.00	0.00	0.00	0.00
Dump Truck	0.53	0.71	0.71	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.35	0.35	0.35	0.35	0.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Diesel Tractor (Yard Dog)	0.00	0.00	0.00	0.00	0.00	0.40	0.40	0.40	0.40	0.40	0.40	0.80	0.80	0.80	0.80	0.80	1.60	1.60	1.60	1.60	1.60	1.60	1.60	2.00	2.00
Service Truck - 1 ton	0.35	0.35	0.35	0.71	0.71	0.71	0.71	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Pile Driver Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck - Fuel/Lube	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Tractor Truck 5th Wheel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Trucks - Pickup 3/4 ton	0.34	0.34	0.34	0.34	0.34	0.41	0.48	0.55	1.03	1.03	1.03	1.03	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72
Trucks - 3 ton	0.18	0.18	0.18	0.18	0.18	0.35	0.35	0.35	0.71	0.71	0.71	0.71	1.06	1.06	1.06	1.06	1.06	1.06	1.06	1.06	1.06	1.06	1.06	1.06	1.06
Truck - Water	0.88	0.88	0.88	0.88	0.88	0.88	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.35	0.53
Off Road Vehicles																									
Air Compressor 185 CFM	0.23	0.23	0.23	0.23	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.69	0.69	0.69	0.92	0.92	0.92	1.15	1.15	1.15	1.15	1.37	1.37
Air Compressor 750 CFM	0.00	0.00	0.00	0.00	0.24	0.24	0.24	0.24	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Articulating Boom Platform	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bob cat loader	0.00	0.00	0.16	0.16	0.16	0.16	0.16	0.63	0.63	0.63	0.63	0.63	0.47	0.47	0.47	0.47	0.47	0.47	0.31	0.31	0.31	0.31	0.31	0.31	0.00
Bulldozer D10R	1.54	1.54	1.54	1.02	1.02	1.02	1.02	1.02	1.02	0.51	0.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bulldozer D6C	1.19	1.19	1.19	1.19	0.80	0.80	0.80	0.80	0.80	0.80	0.40	0.40	0.40	0.40	0.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Concrete Trowel Machine	0.00	0.00	0.00	0.00	0.00	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Concrete Vibrators	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cranes - Mobile 35 ton	0.00	0.00	0.00	0.00	0.00	0.00	0.21	0.21	0.21	0.85	0.85	0.85	0.85	1.48	1.48	1.48	1.48	1.48	1.48	1.48	1.48	1.48	1.48	1.48	1.48
Cranes - Mobile 45 ton	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.76	0.76	0.76	0.76	0.76	0.76	0.76
Crane - Mobile 65 ton	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.19	0.19	0.38	0.76	0.95	0.95	0.95	1.15	1.15	1.15	1.15	1.15	1.15	1.15
Cranes 100 / 150 ton cap	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.15	0.15	0.30	0.30	0.45	0.45	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
Diesel Powered Welder	0.00	0.00	0.00	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.45	0.45	0.45	0.60	0.60	0.60	0.60	0.60	0.75	0.75
Excavator - Backhoe/loader	0.35	0.35	0.53	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.35	0.35	0.35	0.35	0.35	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.00
Excavator - Earth Scraper 637	5.08	5.08	5.08	5.08	2.90	2.90	1.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Excavator - loader	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.28	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Excavator - Motor Grader (CAT140H)	0.00	0.39	0.39	0.39	1.16	1.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Excavator - Trencher (CAT320)	0.00	0.00	0.00	0.00	0.00	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fired Heaters (2,000 BTU)	0.00	0.00	0.00	0.00	0.10	0.10	0.10	0.10	0.08	0.08	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Forklift	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31
Fusion Welder	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Heavy Haul / 600 tn Crane	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38
Heavy Haul / 1,000 tn Crane	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.38	0.38	0.38	0.38	0.38
Light Plants	0.03	0.03	0.05	0.10	0.20	0.20	0.20	0.20	0.10	0.10	0.15	0.15	0.20	0.20	0.25	0.25	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Man lifts - telescoping	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.42	0.42	0.42	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	1.27	1.27	1.27	1.27	1.69	1.69
Man lift - scissor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Portable Compaction Roller	0.00	0.00	1.53	1.53	1.53	1.53	1.53	1.53	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.00
Portable Compaction - Vibratory Plate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.00	0.00	0.00
Portable Compaction - Ram	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pumps	0.08	0.08	0.08	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Portable Power Generators	0.75	0.75	0.75	0.75	1.12	1.12	1.12	1.12	1.12	1.87	1.87	1.87	1.87	1.87	1.87	2.80	2.80	2.80	2.80	2.80	2.80	2.80	3.74	3.74	3.74
Truck Crane - Greater than 300 ton	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.22	0.22	0.22	0.22	0.22	0.45	0.45	0.67	0.67	0.89	0.89	0.89	0.89	0.89
Truck Crane - Greater than 200 ton	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.15	0.15	0.15	0.15	0.15	0.15	0.30	0.30	0.45	0.45	0.45
Vibratory Roller Ingersol-Rand 20 ton	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.47	0.47	0.47	0.47	0.47	0.24	0.24	0.24	0.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WORKER VEHICLES																									
Personal commuting vehicles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
DELIVERY TRUCKS																									
Light delivery truck (e.g. Fed-Ex)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy delivery truck (e.g. flat beds carrying construction eqp)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Import fill trucks	1.5	1.5	1.5	1.5	1.5	1.5	1.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ONSITE TOTAL (lbs/day)	**15.35**	**15.91**	**19.57**	**19.83**	**20.91**	**22.95**	**20.26**	**17.53**	**16.22**	**16.85**	**17.27**	**17.64**	**17.56**	**18.91**	**19.13**	**20.13**	**20.79**	**21.10**	**20.77**	**22.48**	**22.71**	**22.36**	**23.42**	**25.15**	**24.23**
OFF-SITE																									
WORKER VEHICLES																									
Personal commuting vehicles	0.1	0.1	0.2	0.2	0.3	0.4	0.5	0.6	0.7	0.8	1.0	1.2	1.4	1.6	1.9	2.2	2.4	2.5	2.7	2.8	2.9	3.3	3.5	3.8	4.1
DELIVERY TRUCKS																									
Light delivery truck (e.g. Fed-Ex)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy delivery truck (e.g. flat beds carrying construction eqp)	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Import fill trucks	8.4	8.4	8.4	8.4	8.4	8.4	8.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LINEARS																									
ON ROAD																									
Dump Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.71	0.71	1.06	1.06	1.06	1.06	1.06	1.06	1.06	1.06	0.71	0.71	0.00	0.00	0.00
Service Truck (MHD-DSL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.35	0.35	0.35	0.35	0.35	0.35	0.53	0.53	0.53	0.53	0.53	0.53	0.00	0.00	0.00
Pipe Haul Truck and Trailer (HHDT-DSL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.53	0.53	0.53	0.53	0.53	0.53	0.35	0.35	0.35	0.35	0.35	0.35	0.00	0.00	0.00
3/4 Ton Pickup (MHD-DSL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.69	0.69	0.69	0.69	0.69	0.69	1.03	1.03	1.03	1.03	1.03	1.03	0.00	0.00	0.00
Truck - water	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.35	0.35	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.35	0.35	0.00	0.00	0.00
OFF ROAD																									
Air Compressor (185 CFM)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.23	0.23	0.46	0.46	0.69	0.69	0.69	0.69	0.46	0.46	0.23	0.23	0.00	0.00	0.00
Bore Machine (Hydraulic)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.09	0.09	0.09	0.09	0.00	0.00	0.00	0.00	0.00	0.00
12 Ton Hydra Crane	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.30	0.60	0.60	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.60	0.60	0.00	0.00	0.00
Backhoe/loader	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.06	1.06	1.77	1.77	1.77	1.77	1.77	1.77	1.77	1.77	1.06	1.06	0.00	0.00	0.00
Excavator - Trencher	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.00	0.00	0.00
Forklift	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.08	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.08	0.00	0.00	0.00
Welding Generator	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	0.00	0.00	0.00
3 to 5 Ton AC Roller	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.00	0.00	0.00
Pipe Bending Machine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.25	0.25	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.25	0.25	0.00	0.00	0.00	0.00
RAIL																									
AIR COMPRESSOR 185	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.23	0.23	0.23	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BOOM TRUCK 12 TON	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.18	0.18	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAT 325 BACKHOE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAT 330 BACKHOE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAT DOZER D-6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.84	0.84	0.00	0.00	0.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAT MODEL 12 MOTOR GRADER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.77	0.77	0.39	0.39	0.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAT ROLLER-COMPACTOR 563	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.61	0.61	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAT RUBBER TIRE LOADER 966	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.45	0.45	0.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAT SCRAPER 615	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.04	0.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CRANE-ROUGH TERRAIN 45T	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.19	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENSET 5KW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.18	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
JOHN DEERE TRACTOR 9400	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PICK-UP CRAFT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.91	0.91	0.91	0.91	0.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PICK-UP OVERHEAD	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.52	1.56	1.56	1.30	1.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RAIL BALLAST REGULATOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.26	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RAIL CLIP MACHINE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RAIL MOVER-SHUTTLE WAGON	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.26	0.26	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RAIL TAMPER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.26	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RAIL WELDER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RAMEX WALK BEHIND COMPACTOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TRI-AXLE DUMP TRUCK	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.71	1.06	0.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TRUCK FLATBED 14 FOOT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.18	0.18	0.53	0.53	0.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TRUCK TRACTOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.26	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WATER TRUCK, 4M ON-ROAD	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.18	0.18	0.18	0.18	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WELDING MACHINE 350 AMP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.03	0.03	0.03	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LINEARS TOTAL (lbs/day)	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**6.05**	**6.97**	**15.26**	**16.71**	**15.65**	**14.98**	**15.45**	**9.91**	**9.68**	**9.34**	**7.39**	**7.06**	**0.00**	**0.00**	**0.00**
OFFSITE VEHICLES TOTAL (lbs/day)	**11.20**	**11.25**	**11.30**	**11.34**	**11.44**	**11.52**	**11.60**	**3.33**	**3.40**	**3.54**	**3.74**	**3.86**	**4.08**	**4.31**	**4.64**	**4.89**	**5.09**	**5.23**	**5.37**	**5.52**	**5.66**	**6.01**	**6.26**	**6.53**	**6.77**
TOTAL PROJECT (lbs/day)	26.55	27.17	30.86	31.18	32.35	34.47	31.86	20.86	19.62	20.40	27.06	28.47	36.90	39.93	39.41	40.00	41.33	36.24	35.82	37.35	35.76	35.44	29.68	31.68	31.00

CONSTRUCTION VEHICLES	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
ON-SITE																								
On-Road Vehicles																								
18 cy fill mat'l haul truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.53	0.53	0.53	0.53	0.18	0.18	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bus	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.12	2.12	2.12	1.77	1.77	0.88	0.88	0.53	0.53	0.35	0.35	0.35	0.18	0.18
Concrete Pumper Truck	0.00	0.00	0.18	0.18	0.18	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dump Truck	0.00	0.00	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.53	0.53	0.53	0.35	0.18	0.18	0.18	0.18	0.18	0.00	0.00	0.00	0.00
Diesel Tractor (Yard Dog)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Service Truck - 1 ton	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.18	0.18	0.18	0.18	0.18	0.18	0.18
Pile Driver Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck - Fuel/Lube	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.00	0.00	0.00
Tractor Truck 5th Wheel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Trucks - Pickup 3/4 ton	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.03	1.03	0.69	0.69	0.69	0.69	0.34
Trucks - 3 ton	1.06	1.06	1.06	1.06	1.06	1.06	1.06	1.06	1.06	0.71	0.53	0.53	0.53	0.53	0.35	0.35	0.35	0.18	0.18	0.18	0.18	0.00	0.00	0.00
Truck - Water	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.18	0.18	0.18	0.18	0.18	0.18	0.18
Off Road Vehicles																								
Air Compressor 185 CFM	1.37	1.37	1.37	1.37	1.37	1.37	1.37	1.37	1.37	1.37	0.92	0.92	0.92	0.69	0.69	0.69	0.69	0.46	0.46	0.46	0.23	0.23	0.11	0.11
Air Compressor 750 CFM	0.95	0.95	0.95	0.95	0.48	0.48	0.48	0.48	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
Articulating Boom Platform	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bob cat loader	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bulldozer D10R	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bulldozer D6C	0.00	0.00	0.40	0.40	0.40	0.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Concrete Trowel Machine	0.12	0.12	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.12	0.12	0.12	0.12	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Concrete Vibrators	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cranes - Mobile 35 ton	1.48	1.06	1.06	1.06	1.06	1.06	1.06	1.06	1.06	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.21	0.21	0.21	0.21
Cranes - Mobile 45 ton	0.76	0.76	0.76	0.76	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.19	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Crane - Mobile 65 ton	1.15	1.15	1.15	1.15	1.15	0.95	0.95	0.76	0.38	0.38	0.38	0.38	0.38	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.00	0.00	0.00	0.00
Cranes 100 / 150 ton cap	0.60	0.60	0.60	0.30	0.30	0.15	0.15	0.15	0.15	0.15	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Diesel Powered Welder	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.45	0.45	0.45	0.45	0.30	0.30	0.30	0.30	0.30	0.15	0.15	0.15	0.15	0.09	0.09	0.06
Excavator - Backhoe/loader	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.35	0.35	0.35	0.35	0.18	0.18	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Excavator - Earth Scraper 637	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Excavator - loader	0.00	0.00	0.28	0.28	0.28	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.28	0.28	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Excavator - Motor Grader (CAT140H)	0.00	0.00	0.39	0.39	0.39	0.39	0.00	0.00	0.00	0.00	0.77	0.77	0.77	0.77	0.39	0.39	0.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Excavator - Trencher (CAT320)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fired Heaters (2,000 BTU)	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.08	0.08	0.08	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.03	0.03	0.03
Forklift	0.31	0.31	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.08	0.08	0.08	0.08	0.04	0.04	0.04
Fusion Welder	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Heavy Haul / 600 tn Crane	0.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Heavy Haul / 1,000 tn Crane	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Light Plants	0.35	0.35	0.35	0.35	0.35	0.35	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.13	0.13	0.13	0.13	0.13	0.10	0.10	0.05	0.05
Man lifts - telescoping	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.27	1.27	1.27	0.85	0.85	0.85	0.85	0.42	0.42	0.42	0.42	0.17	0.17	0.17
Man lift - scissor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Portable Compaction Roller	0.00	0.00	0.00	0.61	0.61	0.61	0.61	0.61	0.61	0.00	0.00	0.00	0.61	0.61	0.61	0.31	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Portable Compaction - Vibratory Plate	0.00	0.00	0.02	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Portable Compaction - Ram	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pumps	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Portable Power Generators	3.74	3.74	3.74	3.74	3.74	3.74	3.74	3.74	3.74	3.74	2.80	2.80	2.80	2.80	1.87	1.87	1.87	1.87	1.87	1.87	0.93	0.93	0.93	0.37
Truck Crane - Greater than 300 ton	0.89	0.89	0.89	0.89	0.67	0.67	0.45	0.45	0.45	0.22	0.22	0.22	0.22	0.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck Crane - Greater than 200 ton	0.45	0.45	0.45	0.45	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Vibratory Roller Ingersol-Rand 20 ton	0.00	0.00	0.47	0.47	0.47	0.47	0.00	0.00	0.00	0.00	0.00	0.00	0.24	0.24	0.24	0.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WORKER VEHICLES																								
Personal commuting vehicles	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DELIVERY TRUCKS																								
Light delivery truck (e.g. Fed-Ex)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy delivery truck (e.g. flat beds carrying construction eqp)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Import fill trucks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ONSITE TOTAL (lbs/day)	**23.67**	**22.88**	**24.89**	**25.09**	**23.86**	**23.21**	**21.16**	**20.62**	**19.99**	**18.17**	**16.43**	**16.57**	**17.55**	**16.34**	**13.83**	**11.85**	**11.61**	**6.73**	**6.73**	**6.21**	**4.44**	**3.81**	**3.47**	**2.53**
OFF-SITE																								
WORKER VEHICLES																								
Personal commuting vehicles	4.1	4.5	4.8	5.0	5.0	5.1	5.0	4.9	4.7	4.5	4.3	3.9	3.8	3.2	2.6	2.1	1.4	1.1	1.1	1.1	1.0	0.9	0.8	0.6
DELIVERY TRUCKS																								
Light delivery truck (e.g. Fed-Ex)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy delivery truck (e.g. flat beds carrying construction eqp)	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Import fill trucks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LINEARS																								
ON ROAD																								
Dump Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Service Truck (MHD-DSL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pipe Haul Truck and Trailer (HHDT-DSL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3/4 Ton Pickup (MHD-DSL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck - water	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OFF ROAD																								
Air Compressor (185 CFM)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bore Machine (Hydraulic)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12 Ton Hydra Crane	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Backhoe/loader	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Excavator - Trencher	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Forklift	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Welding Generator	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3 to 5 Ton AC Roller	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pipe Bending Machine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RAIL																								
AIR COMPRESSOR 185	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BOOM TRUCK 12 TON	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAT 325 BACKHOE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAT 330 BACKHOE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAT DOZER D-6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAT MODEL 12 MOTOR GRADER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAT ROLLER-COMPACTOR 563	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAT RUBBER TIRE LOADER 966	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAT SCRAPER 615	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CRANE-ROUGH TERRAIN 45T	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENSET 5KW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
JOHN DEERE TRACTOR 9400	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PICK-UP CRAFT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PICK-UP OVERHEAD	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RAIL BALLAST REGULATOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RAIL CLIP MACHINE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RAIL MOVER-SHUTTLE WAGON	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RAIL TAMPER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RAIL WELDER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RAMEX WALK BEHIND COMPACTOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TRI-AXLE DUMP TRUCK	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TRUCK FLATBED 14 FOOT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TRUCK TRACTOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WATER TRUCK, 4M ON-ROAD	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WELDING MACHINE 350 AMP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LINEARS TOTAL (lbs/day)	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
OFFSITE VEHICLES TOTAL (lbs/day)	**6.82**	**7.22**	**7.54**	**7.70**	**7.73**	**7.78**	**7.70**	**7.66**	**7.44**	**7.18**	**7.04**	**6.65**	**6.52**	**5.94**	**5.34**	**4.79**	**4.13**	**3.84**	**3.84**	**3.84**	**3.76**	**3.60**	**3.52**	**3.33**
TOTAL PROJECT (lbs/day)	30.49	30.10	32.43	32.79	31.58	30.99	28.86	28.28	27.43	25.35	23.47	23.22	24.07	22.29	19.17	16.65	15.73	10.57	10.57	10.05	8.19	7.41	6.99	5.86

Notes:

1. According to schedules provided by Fluor, Linear construction (except rail) takes place in months 11-22.
2. According to schedules provided by Fluor, Rail construction occurs in months 13-17.

Hydrogen Energy California, Kern County Power Project
PM2.5 Emissions by Month - from Combustion Sources
8/14/2012

PM2.5 - Combustion	MONTHLY EMISSIONS (lbs/day)																																																
CONSTRUCTION VEHICLES	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
ON-SITE																																																	
On-Road Vehicles																																																	
18 cy fill mat'l haul truck	0.0	0.0	1.6	1.6	3.2	3.2	3.2	3.2	1.6	1.6	1.6	1.6	0.8	0.8	0.8	0.8	0.8	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bus	0.3	0.3	0.3	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.8	0.8	0.8	0.8	0.8	0.8	1.1	1.1	1.1	1.6	1.6	1.6	1.6	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	1.9	1.9	1.9	1.6	1.6	0.8	0.8	0.5	0.5	0.3	0.3	0.3	0.2	0.2
Concrete Pumper Truck	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5	0.5	0.3	0.3	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dump Truck	0.5	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.3	0.3	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5	0.5	0.3	0.2	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0
Diesel Tractor (Yard Dog)	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.4	0.4	0.4	0.4	0.7	0.7	0.7	0.7	0.7	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Service Truck - 1 ton	0.3	0.3	0.3	0.6	0.6	0.6	0.6	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Pile Driver Truck	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck - Fuel/Lube	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0
Tractor Truck 5th Wheel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trucks - Pickup 3/4 ton	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.5	0.9	0.9	0.9	0.9	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	0.9	0.9	0.6	0.6	0.6	0.6	0.3
Trucks - 3 ton	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.6	0.6	0.6	0.6	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.6	0.5	0.5	0.5	0.5	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.0	0.0	0.0
Truck - Water	0.8	0.8	0.8	0.8	0.8	0.8	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.3	0.5	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Off Road Vehicles																																																	
Air Compressor 185 CFM	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.6	0.6	0.6	0.8	0.8	0.8	1.1	1.1	1.1	1.1	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	0.8	0.8	0.8	0.6	0.6	0.6	0.6	0.4	0.4	0.4	0.2	0.2	0.1	0.1
Air Compressor 750 CFM	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.4	0.4	0.4	0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Articulating Boom Platform	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bob cat loader	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.6	0.6	0.6	0.6	0.6	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bulldozer D10R	1.4	1.4	1.4	0.9	0.9	0.9	0.9	0.9	0.9	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bulldozer D6C	1.1	1.1	1.1	1.1	0.7	0.7	0.7	0.7	0.7	0.7	0.4	0.4	0.4	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Concrete Trowel Machine	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Concrete Vibrators	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cranes - Mobile 35 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.8	0.8	0.8	0.8	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.2	0.2	0.2	0.2
Cranes - Mobile 45 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Crane - Mobile 65 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.4	0.7	0.9	0.9	0.9	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	0.9	0.9	0.7	0.4	0.4	0.4	0.4	0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0
Cranes 100 / 150 ton cap	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.3	0.3	0.4	0.4	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.3	0.3	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Diesel Powered Welder	0.0	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Excavator - Backhoe/loader	0.3	0.3	0.5	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Earth Scraper 637	4.7	4.7	4.7	4.7	2.7	2.7	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - loader	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Motor Grader (CAT140H)	0.0	0.4	0.4	0.4	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Trencher (CAT320)	0.0	0.0	0.0	0.0	0.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.4	0.4	0.0	0.0	0.0	0.0	0.7	0.7	0.7	0.7	0.4	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fired Heaters (2,000 BTU)	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Forklift	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.0	0.0	0.0
Fusion Welder	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Haul / 600 tn Crane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Haul / 1,000 tn Crane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Light Plants	0.0	0.0	0.0	0.1	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0
Man lifts - telescoping	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.4	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	1.2	1.2	1.2	1.2	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.2	1.2	1.2	0.8	0.8	0.8	0.8	0.4	0.4	0.4	0.4	0.2	0.2	0.2
Man lift - scissor	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Compaction Roller	0.0	0.0	1.4	1.4	1.4	1.4	1.4	1.4	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.0	0.0	0.0	0.0	0.6	0.6	0.6	0.6	0.6	0.6	0.0	0.0	0.0	0.6	0.6	0.6	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Compaction - Vibratory Plate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Compaction - Ram	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumps	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Power Generators	0.7	0.7	0.7	0.7	1.0	1.0	1.0	1.0	1.0	1.7	1.7	1.7	1.7	1.7	1.7	2.6	2.6	2.6	2.6	2.6	2.6	2.6	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	2.6	2.6	2.6	2.6	1.7	1.7	1.7	1.7	1.7	1.7	0.9	0.9	0.9	0.3
Truck Crane - Greater than 300 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.4	0.4	0.6	0.6	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.6	0.6	0.4	0.4	0.4	0.2	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck Crane - Greater than 200 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Vibratory Roller Ingersol-Rand 20 ton	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.4	0.4	0.4	0.4	0.4	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WORKER VEHICLES																																																	
Personal commuting vehicles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DELIVERY TRUCKS																																																	
Light delivery truck (e.g. Fed-Ex)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy delivery truck (e.g. flat beds carrying construction eqp)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Import fill trucks	1.4	1.4	1.4	1.4	1.4	1.4	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ONSITE TOTAL (lbs/day)	**14.0**	**14.6**	**17.9**	**18.1**	**19.1**	**20.9**	**18.5**	**16.0**	**14.8**	**15.4**	**15.8**	**16.1**	**16.0**	**17.2**	**17.5**	**18.4**	**19.0**	**19.2**	**19.0**	**20.5**	**20.7**	**20.4**	**21.4**	**23.0**	**22.1**	**21.6**	**20.9**	**22.7**	**22.9**	**21.8**	**21.2**	**19.3**	**18.8**	**18.2**	**16.5**	**15.0**	**15.1**	**16.0**	**14.9**	**12.6**	**10.8**	**10.6**	**6.1**	**6.1**	**5.7**	**4.0**	**3.5**	**3.2**	**2.3**
OFF-SITE																																																	
WORKER VEHICLES																																																	
Personal commuting vehicles	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.4	0.4	0.5	0.6	0.7	0.8	1.0	1.1	1.2	1.3	1.4	1.5	1.5	1.7	1.9	2.0	2.1	2.2	2.4	2.5	2.6	2.6	2.7	2.6	2.6	2.5	2.3	2.3	2.1	2.0	1.7	1.4	1.1	0.7	0.6	0.6	0.6	0.5	0.5	0.4	0.3
DELIVERY TRUCKS																																																	
Light delivery truck (e.g. Fed-Ex)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy delivery truck (e.g. flat beds carrying construction eqp)	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Import fill trucks	7.2	7.2	7.2	7.2	7.2	7.2	7.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LINEARS																																																	
ON ROAD																																																	
Dump Truck	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Service Truck (MHD-DSL)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipe Haul Truck and Trailer (HHDT-DSL)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.3	0.3	0.3	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3/4 Ton Pickup (MHD-DSL)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.6	0.6	0.6	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck - water	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OFF ROAD																																																	
Air Compressor (185 CFM)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.4	0.4	0.6	0.6	0.6	0.6	0.4	0.4	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bore Machine (Hydraulic)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12 Ton Hydra Crane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.6	0.6	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Backhoe/loader	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Trencher	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Forklift	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Welding Generator	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3 to 5 Ton AC Roller	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipe Bending Machine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL																																																	
AIR COMPRESSOR 185	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BOOM TRUCK 12 TON	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT 325 BACKHOE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT 330 BACKHOE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT DOZER D-6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.8	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT MODEL 12 MOTOR GRADER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.7	0.4	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT ROLLER-COMPACTOR 563	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT RUBBER TIRE LOADER 966	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT SCRAPER 615	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CRANE-ROUGH TERRAIN 45T	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GENSET 5KW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
JOHN DEERE TRACTOR 9400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PICK-UP CRAFT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.8	0.8	0.8	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PICK-UP OVERHEAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	1.4	1.4	1.2	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL BALLAST REGULATOR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL CLIP MACHINE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL MOVER-SHUTTLE WAGON	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL TAMPER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL WELDER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAMEX WALK BEHIND COMPACTOR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRI-AXLE DUMP TRUCK	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	1.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRUCK FLATBED 14 FOOT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRUCK TRACTOR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WATER TRUCK, 4M ON-ROAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WELDING MACHINE 350 AMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LINEARS TOTAL (lbs/day)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**5.5**	**6.4**	**14.0**	**15.3**	**14.3**	**13.7**	**14.1**	**9.0**	**8.8**	**8.5**	**6.7**	**6.4**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
OFFSITE VEHICLES TOTAL (lbs/day)	**9.6**	**9.6**	**9.6**	**9.7**	**9.7**	**9.7**	**9.8**	**2.6**	**2.7**	**2.8**	**2.9**	**2.9**	**3.0**	**3.2**	**3.3**	**3.5**	**3.6**	**3.6**	**3.7**	**3.8**	**3.9**	**4.0**	**4.2**	**4.3**	**4.4**	**4.5**	**4.7**	**4.9**	**4.9**	**4.9**	**5.0**	**4.9**	**4.9**	**4.8**	**4.7**	**4.6**	**4.4**	**4.3**	**4.0**	**3.7**	**3.4**	**3.1**	**2.9**	**2.9**	**2.9**	**2.9**	**2.8**	**2.7**	**2.6**
TOTAL PROJECT (lbs/day)	23.6	24.2	27.5	27.8	28.8	30.7	28.3	18.6	17.5	18.1	24.1	25.4	33.0	35.7	35.1	35.5	36.7	31.9	31.5	32.8	31.3	30.9	25.6	27.3	26.6	26.1	25.6	27.6	27.8	26.7	26.1	24.2	23.7	23.0	21.2	19.6	19.5	20.3	18.9	16.3	14.2	13.6	9.0	9.0	8.6	6.9	6.3	5.9	4.9

Notes:

1. According to schedules provided by Fluor, Linear construction (except rail) takes place in months 11-22.
2. According to schedules provided by Fluor, Rail construction occurs in months 13-17.

Hydrogen Energy California, Kern County Power Project
Sulfur Dioxide (SO2) Emissions by Month
8/14/2012

SO2 MONTHLY EMISSIONS (lbs/day)

CONSTRUCTION VEHICLES	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
ON-SITE																																																	
On-Road Vehicles																																																	
18 cy fill mat'l haul truck	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bus	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Concrete Pumper Truck	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dump Truck	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Diesel Tractor (Yard Dog)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Service Truck - 1 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pile Driver Truck	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck - Fuel/Lube	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tractor Truck 5th Wheel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trucks - Pickup 3/4 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trucks - 3 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck - Water	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Off Road Vehicles																																																	
Air Compressor 185 CFM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Air Compressor 750 CFM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Articulating Boom Platform	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bob cat loader	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bulldozer D10R	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bulldozer D6C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Concrete Trowel Machine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Concrete Vibrators	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cranes - Mobile 35 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cranes - Mobile 45 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Crane - Mobile 65 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cranes 100 / 150 ton cap	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Diesel Powered Welder	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Backhoe/loader	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Earth Scraper 637	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - loader	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Motor Grader (CAT140H)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Trencher (CAT320)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fired Heaters (2,000 BTU)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Forklift	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fusion Welder	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Haul / 600 tn Crane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Haul / 1,000 tn Crane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Light Plants	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Man lifts - telescoping	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Man lift - scissor	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Compaction Roller	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Compaction - Vibratory Plate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Compaction - Ram	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumps	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Power Generators	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck Crane - Greater than 300 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck Crane - Greater than 200 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Vibratory Roller Ingersol-Rand 20 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WORKER VEHICLES																																																	
Personal commuting vehicles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DELIVERY TRUCKS																																																	
Light delivery truck (e.g. Fed-Ex)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy delivery truck (e.g. flat beds carrying construction eqp)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Import fill trucks	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ONSITE TOTAL (lbs/day)	**0.3**	**0.3**	**0.4**	**0.4**	**0.4**	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.5**	**0.5**	**0.4**	**0.4**	**0.5**	**0.4**	**0.4**	**0.4**	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.2**	**0.2**	**0.2**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.0**
OFF-SITE																																																	
WORKER VEHICLES																																																	
Personal commuting vehicles	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.4	0.4	0.3	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
DELIVERY TRUCKS																																																	
Light delivery truck (e.g. Fed-Ex)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy delivery truck (e.g. flat beds carrying construction eqp)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Import fill trucks	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LINEARS																																																	
ON ROAD																																																	
Dump Truck	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Service Truck (MHD-DSL)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipe Haul Truck and Trailer (HHDT-DSL)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3/4 Ton Pickup (MHD-DSL)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck - water	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OFF ROAD																																																	
Air Compressor (185 CFM)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bore Machine (Hydraulic)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12 Ton Hydra Crane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Backhoe/loader	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Trencher	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Forklift	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Welding Generator	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3 to 5 Ton AC Roller	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipe Bending Machine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL																																																	
AIR COMPRESSOR 185	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BOOM TRUCK 12 TON	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT 325 BACKHOE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT 330 BACKHOE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT DOZER D-6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT MODEL 12 MOTOR GRADER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT ROLLER-COMPACTOR 563	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT RUBBER TIRE LOADER 966	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT SCRAPER 615	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CRANE-ROUGH TERRAIN 45T	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GENSET 5KW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
JOHN DEERE TRACTOR 9400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PICK-UP CRAFT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PICK-UP OVERHEAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL BALLAST REGULATOR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL CLIP MACHINE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL MOVER-SHUTTLE WAGON	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL TAMPER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL WELDER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAMEX WALK BEHIND COMPACTOR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRI-AXLE DUMP TRUCK	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRUCK FLATBED 14 FOOT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRUCK TRACTOR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WATER TRUCK, 4M ON-ROAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WELDING MACHINE 350 AMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LINEARS TOTAL (lbs/day)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.1**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.2**	**0.2**	**0.2**	**0.1**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
OFFSITE VEHICLES TOTAL (lbs/day)	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.1**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.4**	**0.4**	**0.4**	**0.4**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.7**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.5**	**0.5**	**0.4**	**0.4**	**0.3**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.1**
TOTAL PROJECT (lbs/day)	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.4	0.4	0.4	0.6	0.6	0.8	0.9	1.0	1.0	1.0	0.9	0.9	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.0	1.0	1.0	0.9	0.9	0.8	0.8	0.7	0.6	0.5	0.4	0.3	0.3	0.3	0.3	0.2	0.2	0.2

Notes:

1. According to schedules provided by Fluor, Linear construction (except rail) takes place in months 11-22.
2. According to schedules provided by Fluor, Rail construction occurs in months 13-17.

ROG

MONTHLY EMISSIONS (lbs/day)

CONSTRUCTION VEHICLES	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
ON-SITE																																																	
On-Road Vehicles																																																	
18 cy fill mat'l haul truck	0.0	0.0	6.2	6.2	12.4	12.4	12.4	12.4	6.2	6.2	6.2	6.2	3.1	3.1	3.1	3.1	3.1	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	1.9	1.9	1.9	0.6	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bus	1.2	1.2	1.2	1.2	1.9	1.9	1.9	1.9	1.9	1.9	3.1	3.1	3.1	3.1	3.1	3.1	4.3	4.3	4.3	6.2	6.2	6.2	6.2	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	7.4	7.4	7.4	6.2	6.2	3.1	3.1	1.9	1.9	1.2	1.2	1.2	0.6	0.6
Concrete Pumper Truck	0.0	0.0	0.0	0.0	0.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.9	1.9	1.2	1.2	1.2	1.2	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.6	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dump Truck	1.9	2.5	2.5	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.2	1.2	1.2	1.2	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.9	1.9	1.9	1.2	0.6	0.6	0.6	0.6	0.6	0.0	0.0	0.0	0.0
Diesel Tractor (Yard Dog)	0.0	0.0	0.0	0.0	0.0	1.4	1.4	1.4	1.4	1.4	1.4	2.8	2.8	2.8	2.8	2.8	5.6	5.6	5.6	5.6	5.6	5.6	5.6	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	2.8	2.8	2.8	2.8	2.8	2.8	2.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Service Truck - 1 ton	1.2	1.2	1.2	2.5	2.5	2.5	2.5	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Pile Driver Truck	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck - Fuel/Lube	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0
Tractor Truck 5th Wheel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trucks - Pickup 3/4 ton	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.5	0.9	0.9	0.9	0.9	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	0.9	0.9	0.6	0.6	0.6	0.6	0.3
Trucks - 3 ton	0.6	0.6	0.6	0.6	0.6	1.2	1.2	1.2	2.5	2.5	2.5	2.5	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	2.5	1.9	1.9	1.9	1.9	1.2	1.2	1.2	0.6	0.6	0.6	0.6	0.0	0.0	0.0
Truck - Water	3.1	3.1	3.1	3.1	3.1	3.1	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.2	1.9	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Off Road Vehicles																																																	
Air Compressor 185 CFM	1.0	1.0	1.0	1.0	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	2.9	2.9	2.9	3.9	3.9	3.9	4.9	4.9	4.9	4.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	3.9	3.9	3.9	2.9	2.9	2.9	2.9	2.0	2.0	2.0	1.0	1.0	0.5	0.5
Air Compressor 750 CFM	0.0	0.0	0.0	0.0	0.4	0.4	0.4	0.4	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	0.9	0.9	0.9	0.9	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Articulating Boom Platform	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bob cat loader	0.0	0.0	0.6	0.6	0.6	0.6	0.6	2.6	2.6	2.6	2.6	2.6	1.9	1.9	1.9	1.9	1.9	1.9	1.3	1.3	1.3	1.3	1.3	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bulldozer D10R	4.5	4.5	4.5	3.0	3.0	3.0	3.0	3.0	3.0	1.5	1.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bulldozer D6C	2.3	2.3	2.3	2.3	1.5	1.5	1.5	1.5	1.5	1.5	0.8	0.8	0.8	0.8	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.8	0.8	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Concrete Trowel Machine	0.0	0.0	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Concrete Vibrators	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cranes - Mobile 35 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.4	1.6	1.6	1.6	1.6	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.4	0.4	0.4	0.4
Cranes - Mobile 45 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	0.9	0.9	0.9	0.9	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Crane - Mobile 65 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.9	1.8	2.2	2.2	2.2	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.2	2.2	1.8	0.9	0.9	0.9	0.9	0.9	0.4	0.4	0.4	0.4	0.4	0.4	0.0	0.0	0.0	0.0	0.0
Cranes 100 / 150 ton cap	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.4	0.9	1.3	1.3	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	0.9	0.9	0.4	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Diesel Powered Welder	0.0	0.0	0.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.5	1.5	1.5	2.0	2.0	2.0	2.0	2.0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	1.5	1.5	1.5	1.5	1.0	1.0	1.0	1.0	1.0	0.5	0.5	0.5	0.5	0.3	0.3	0.2
Excavator - Backhoe/loader	0.6	0.6	1.0	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	0.6	0.6	0.6	0.6	0.6	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.6	0.6	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Earth Scraper 637	14.7	14.7	14.7	14.7	8.4	8.4	4.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - loader	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Motor Grader (CAT140H)	0.0	0.7	0.7	0.7	2.2	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.7	0.7	0.7	0.0	0.0	0.0	0.0	1.4	1.4	1.4	1.4	0.7	0.7	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Trencher (CAT320)	0.0	0.0	0.0	0.0	0.0	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fired Heaters (2,000 BTU)	0.0	0.0	0.0	0.0	0.4	0.4	0.4	0.4	0.3	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1
Forklift	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.3	0.3	0.3	0.3	0.1	0.1	0.1
Fusion Welder	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Haul / 600 tn Crane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Haul / 1,000 tn Crane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	1.1	1.1	1.1	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Light Plants	0.1	0.1	0.2	0.4	0.8	0.8	0.8	0.8	0.4	0.4	0.6	0.6	0.8	0.8	1.0	1.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.2	0.2
Man lifts - telescoping	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.6	1.6	1.6	3.3	3.3	3.3	3.3	3.3	3.3	3.3	4.9	4.9	4.9	4.9	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	4.9	4.9	4.9	3.3	3.3	3.3	3.3	1.6	1.6	1.6	1.6	0.7	0.7
Man lift - scissor	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Compaction Roller	0.0	0.0	2.8	2.8	2.8	2.8	2.8	2.8	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	0.0	0.0	0.0	0.0	0.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Compaction - Vibratory Plate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Compaction - Ram	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumps	0.3	0.3	0.3	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Portable Power Generators	2.9	2.9	2.9	2.9	4.3	4.3	4.3	4.3	4.3	7.2	7.2	7.2	7.2	7.2	7.2	10.7	10.7	10.7	10.7	10.7	10.7	10.7	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	10.7	10.7	10.7	10.7	7.2	7.2	7.2	7.2	7.2	7.2	3.6	3.6	3.6	1.4
Truck Crane - Greater than 300 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.7	0.7	0.7	0.7	0.7	1.3	1.3	2.0	2.0	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.0	2.0	1.3	1.3	1.3	0.7	0.7	0.7	0.7	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck Crane - Greater than 200 ton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.4	0.4	0.9	0.9	0.9	1.3	1.3	1.3	1.3	1.3	1.3	1.3	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Vibratory Roller Ingersol-Rand 20 ton	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.1	1.1	1.1	1.1	1.1	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	1.1	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WORKER VEHICLES																																																	
Personal commuting vehicles	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.3	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
DELIVERY TRUCKS																																																	
Light delivery truck (e.g. Fed-Ex)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy delivery truck (e.g. flat beds carrying construction eqp)	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Import fill trucks	6.5	6.5	6.5	6.5	6.5	6.5	6.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ONSITE TOTAL (lbs/day)	**46.2**	**47.6**	**57.7**	**58.6**	**62.9**	**68.5**	**61.3**	**51.5**	**46.9**	**48.9**	**50.5**	**52.6**	**50.8**	**54.5**	**55.5**	**58.9**	**63.0**	**63.8**	**62.1**	**68.1**	**68.8**	**67.6**	**71.5**	**77.9**	**75.8**	**74.1**	**72.2**	**77.0**	**76.7**	**73.9**	**72.1**	**67.3**	**65.7**	**64.3**	**60.1**	**51.4**	**52.0**	**53.7**	**49.3**	**41.4**	**35.6**	**35.0**	**20.8**	**20.8**	**19.9**	**13.8**	**11.7**	**10.4**	**7.8**
OFF-SITE																																																	
WORKER VEHICLES																																																	
Personal commuting vehicles	0.2	0.4	0.5	0.6	0.9	1.2	1.4	1.8	2.1	2.5	3.1	3.4	4.1	4.8	5.7	6.5	7.1	7.5	7.9	8.4	8.8	9.8	10.6	11.4	12.1	12.2	13.5	14.4	14.9	15.0	15.1	14.9	14.8	14.1	13.3	12.9	11.7	11.4	9.6	7.8	6.2	4.2	3.4	3.4	3.4	3.1	2.6	2.4	1.8
DELIVERY TRUCKS																																																	
Light delivery truck (e.g. Fed-Ex)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Heavy delivery truck (e.g. flat beds carrying construction eqp)	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Import fill trucks	10.4	10.4	10.4	10.4	10.4	10.4	10.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LINEARS																																																	
ON ROAD																																																	
Dump Truck	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	2.5	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	2.5	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Service Truck (MHD-DSL)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	1.2	1.2	1.2	1.2	1.2	1.9	1.9	1.9	1.9	1.9	1.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipe Haul Truck and Trailer (HHDT-DSL)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	1.9	1.9	1.9	1.9	1.9	1.2	1.2	1.2	1.2	1.2	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3/4 Ton Pickup (MHD-DSL)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.6	0.6	0.6	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck - water	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	1.2	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	1.2	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OFF ROAD																																																	
Air Compressor (185 CFM)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0	2.0	2.0	2.9	2.9	2.9	2.9	2.0	2.0	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bore Machine (Hydraulic)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12 Ton Hydra Crane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	1.8	1.8	2.7	2.7	2.7	2.7	2.7	2.7	2.7	1.8	1.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Backhoe/loader	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	1.9	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	1.9	1.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Trencher	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Forklift	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Welding Generator	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3 to 5 Ton AC Roller	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipe Bending Machine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	0.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	0.9	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL																																																	
AIR COMPRESSOR 185	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BOOM TRUCK 12 TON	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT 325 BACKHOE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT 330 BACKHOE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT DOZER D-6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	2.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT MODEL 12 MOTOR GRADER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	1.4	0.7	0.7	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT ROLLER-COMPACTOR 563	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	1.1	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT RUBBER TIRE LOADER 966	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	1.4	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT SCRAPER 615	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.0	1.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CRANE-ROUGH TERRAIN 45T	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GENSET 5KW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
JOHN DEERE TRACTOR 9400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PICK-UP CRAFT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.7	2.7	2.7	2.7	2.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PICK-UP OVERHEAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	3.5	3.5	2.9	2.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL BALLAST REGULATOR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL CLIP MACHINE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL MOVER-SHUTTLE WAGON	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL TAMPER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL WELDER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAMEX WALK BEHIND COMPACTOR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRI-AXLE DUMP TRUCK	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	3.7	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRUCK FLATBED 14 FOOT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	1.9	1.9	1.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRUCK TRACTOR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WATER TRUCK, 4M ON-ROAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.6	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WELDING MACHINE 350 AMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LINEARS TOTAL (lbs/day)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**18.1**	**20.8**	**43.5**	**47.3**	**45.8**	**44.0**	**44.3**	**29.2**	**28.2**	**27.1**	**21.4**	**20.2**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
OFFSITE VEHICLES TOTAL (lbs/day)	**14.0**	**14.1**	**14.3**	**14.4**	**14.7**	**14.9**	**15.2**	**5.2**	**5.5**	**5.9**	**6.5**	**6.8**	**7.5**	**8.2**	**9.1**	**9.9**	**10.5**	**10.9**	**11.3**	**11.8**	**12.2**	**13.2**	**14.0**	**14.8**	**15.5**	**15.6**	**16.9**	**17.8**	**18.3**	**18.4**	**18.5**	**18.3**	**18.1**	**17.5**	**16.7**	**16.3**	**15.1**	**14.8**	**13.0**	**11.2**	**9.6**	**7.6**	**6.8**	**6.8**	**6.8**	**6.5**	**6.0**	**5.8**	**5.2**
TOTAL PROJECT (lbs/day)	60.2	61.7	71.9	73.0	77.6	83.4	76.5	56.8	52.4	54.8	75.1	80.2	101.8	110.0	110.4	112.8	117.8	104.0	101.6	107.0	102.4	101.1	85.5	92.7	91.3	89.7	89.1	94.8	95.0	92.2	90.6	85.6	83.8	81.8	76.8	67.7	67.1	68.4	62.3	52.6	45.2	42.6	27.6	27.6	26.7	20.3	17.7	16.2	13.0

Notes:

1. According to schedules provided by Fluor, Linear construction (except rail) takes place in months 11-22.
2. According to schedules provided by Fluor, Rail construction occurs in months 13-17.

Hydrogen Energy California, Kern County Power Project
Carbon Dioxide Equivalents (CO2e) Emissions by Month
8/14/2012

CO2e	MONTHLY EMISSIONS (lbs/day)																																																
CONSTRUCTION VEHICLES	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
ON-SITE																																																	
On-Road Vehicles																																																	
18 cy fill mat'l haul truck	0	0	2,876	2,876	5,753	5,753	5,753	5,753	2,876	2,876	2,876	2,876	1,438	1,438	1,438	1,438	1,438	1,438	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	863	863	863	863	288	288	288	0	0	0	0	0	0	0
Bus	575	575	575	575	863	863	863	863	863	863	1,438	1,438	1,438	1,438	1,438	1,438	2,013	2,013	2,013	2,876	2,876	2,876	2,876	4,027	4,027	4,027	4,027	4,027	4,027	4,027	4,027	4,027	4,027	4,027	4,027	3,452	3,452	3,452	2,876	2,876	1,438	1,438	863	863	575	575	575	288	288
Concrete Pumper Truck	0	0	0	0	0	575	575	575	575	575	575	575	575	863	863	863	575	575	575	575	575	0	0	0	0	0	0	288	288	288	288	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dump Truck	863	1,151	1,151	863	863	863	863	863	863	863	575	575	575	575	575	0	0	0	0	0	0	0	0	0	0	0	0	575	575	575	575	575	575	575	575	575	863	863	863	575	288	288	288	288	288	0	0	0	0
Diesel Tractor (Yard Dog)	0	0	0	0	0	652	652	652	652	652	652	1,305	1,305	1,305	1,305	1,305	2,610	2,610	2,610	2,610	2,610	2,610	2,610	3,262	3,262	3,262	3,262	3,262	3,262	3,262	3,262	3,262	3,262	3,262	3,262	1,305	1,305	1,305	1,305	1,305	1,305	1,305	0	0	0	0	0	0	0
Service Truck - 1 ton	575	575	575	1,151	1,151	1,151	1,151	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	288	288	288	288	288	288	288
Pile Driver Truck	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck - Fuel/Lube	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	137	137	137	137	137	137	137	0	0	0
Tractor Truck 5th Wheel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trucks - Pickup 3/4 ton	684	684	684	684	684	821	958	1,095	2,053	2,053	2,053	2,053	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	2,053	2,053	1,369	1,369	1,369	1,369	684
Trucks - 3 ton	288	288	288	288	288	575	575	575	1,151	1,151	1,151	1,151	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,151	863	863	863	863	575	575	575	288	288	288	288	0	0	0
Truck - Water	1,438	1,438	1,438	1,438	1,438	1,438	863	863	863	863	863	863	863	863	863	863	863	863	863	863	863	863	863	575	863	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	575	288	288	288	288	288	288	288
Off Road Vehicles																																																	
Air Compressor 185 CFM	217	217	217	217	326	326	326	326	326	326	326	326	326	651	651	651	869	869	869	1,086	1,086	1,086	1,086	1,303	1,303	1,303	1,303	1,303	1,303	1,303	1,303	1,303	1,303	1,303	1,303	869	869	869	651	651	651	651	434	434	434	217	217	109	109
Air Compressor 750 CFM	0	0	0	0	228	228	228	228	456	456	456	456	456	456	456	912	912	912	912	912	912	912	912	912	912	912	912	912	912	456	456	456	456	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
Articulating Boom Platform	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bob cat loader	0	0	170	170	170	170	170	681	681	681	681	681	511	511	511	511	511	511	340	340	340	340	340	340	0	0	0	0	0	0	0	0	0	0	0	170	170	170	170	170	170	170	0	0	0	0	0	0	0
Bulldozer D10R	4,624	4,624	4,624	3,082	3,082	3,082	3,082	3,082	3,082	1,541	1,541	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bulldozer D6C	1,176	1,176	1,176	1,176	784	784	784	784	784	784	392	392	392	392	392	0	0	0	0	0	0	0	0	0	0	0	0	392	392	392	392	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Concrete Trowel Machine	0	0	0	0	0	141	141	141	141	141	141	141	141	141	141	141	141	141	141	141	141	141	141	141	141	141	141	141	0	0	0	0	0	0	0	0	141	141	141	141	141	141	0	0	0	0	0	0	0
Concrete Vibrators	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cranes - Mobile 35 ton	0	0	0	0	0	0	218	218	218	872	872	872	872	1,526	1,526	1,526	1,526	1,526	1,526	1,526	1,526	1,526	1,526	1,526	1,526	1,526	1,090	1,090	1,090	1,090	1,090	1,090	1,090	1,090	436	436	436	436	436	436	436	436	436	436	436	218	218	218	218
Cranes - Mobile 45 ton	0	0	0	0	0	0	0	0	0	0	697	697	697	697	697	697	697	697	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395	697	697	697	697	697	697	697	697	697	697	697	349	349	0	0	0	0	0	0	0
Crane - Mobile 65 ton	0	0	0	0	0	0	0	0	0	0	0	349	349	697	1,395	1,743	1,743	1,743	2,092	2,092	2,092	2,092	2,092	2,092	2,092	2,092	2,092	2,092	2,092	2,092	1,743	1,743	1,395	697	697	697	697	697	349	349	349	349	349	349	349	0	0	0	0
Cranes 100 / 150 ton cap	0	0	0	0	0	0	0	0	0	0	486	486	973	973	1,459	1,459	1,946	1,946	1,946	1,946	1,946	1,946	1,946	1,946	1,946	1,946	1,946	1,946	973	973	486	486	486	486	486	486	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel Powered Welder	0	0	0	513	513	513	513	513	513	513	513	513	513	513	513	770	770	770	1,026	1,026	1,026	1,026	1,026	1,283	1,283	1,283	1,283	1,283	1,283	1,283	1,283	1,283	770	770	770	770	770	513	513	513	513	513	257	257	257	257	154	154	103
Excavator - Backhoe/loader	486	486	729	972	972	972	972	972	972	972	972	486	486	486	486	486	243	243	243	243	243	243	243	243	0	0	0	0	0	0	0	0	0	0	0	486	486	486	486	243	243	243	0	0	0	0	0	0	0
Excavator - Earth Scraper 637	14,945	14,945	14,945	14,945	8,540	8,540	4,270	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator - loader	642	642	642	642	642	642	642	642	642	642	642	642	321	321	0	0	0	0	0	0	0	0	0	0	0	0	0	321	321	321	321	0	0	0	0	0	0	321	321	321	0	0	0	0	0	0	0	0	0
Excavator - Motor Grader (CAT140H)	0	434	434	434	1,303	1,303	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	434	434	434	434	0	0	0	0	869	869	869	869	434	434	434	0	0	0	0	0	0	0
Excavator - Trencher (CAT320)	0	0	0	0	0	910	910	910	910	910	910	910	910	910	910	910	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fired Heaters (2,000 BTU)	0	0	0	0	330	330	330	330	248	248	413	413	413	413	413	413	413	413	413	413	413	413	413	413	413	413	413	413	413	413	413	413	248	248	248	165	165	165	165	165	165	165	165	165	165	165	83	83	83
Forklift	269	269	269	269	269	269	269	269	269	269	269	269	269	269	269	269	358	358	358	358	358	358	358	358	358	358	358	269	269	269	269	269	269	269	269	269	269	269	269	269	269	269	90	90	90	90	45	45	45
Fusion Welder	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Heavy Haul / 600 tn Crane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,315	1,315	1,315	1,315	1,315	1,315	1,315	1,315	1,315	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Heavy Haul / 1,000 tn Crane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,315	1,315	1,315	1,315	1,315	1,315	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Light Plants	83	83	165	330	661	661	661	661	330	330	496	496	661	661	826	826	1,156	1,156	1,156	1,156	1,156	1,156	1,156	1,156	1,156	1,156	1,156	1,156	1,156	1,156	1,156	826	826	826	826	826	826	826	826	826	413	413	413	413	413	330	330	165	165
Man lifts - telescoping	0	0	0	0	0	0	0	0	502	502	502	1,005	1,005	1,005	1,005	1,005	1,005	1,005	1,005	1,507	1,507	1,507	1,507	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009	2,009	1,507	1,507	1,507	1,005	1,005	1,005	1,005	502	502	502	502	201	201	201
Man lift - scissor	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Portable Compaction Roller	0	0	1,712	1,712	1,712	1,712	1,712	1,712	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	0	0	0	0	685	685	685	685	685	685	0	0	0	685	685	685	342	342	0	0	0	0	0	0	0
Portable Compaction - Vibratory Plate	0	0	0	0	0	0	0	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	0	0	0	0	0	56	56	56	56	0	0	0	0	75	75	75	75	75	38	38	0	0	0	0	0	0	0
Portable Compaction - Ram	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pumps	248	248	248	496	496	496	496	496	496	496	496	496	496	496	496	496	496	248	248	248	248	248	248	248	248	248	248	248	248	248	248	248	248	248	248	248	248	248	248	248	248	248	165	165	165	165	165	165	165
Portable Power Generators	916	916	916	916	1,374	1,374	1,374	1,374	1,374	2,291	2,291	2,291	2,291	2,291	2,291	3,436	3,436	3,436	3,436	3,436	3,436	3,436	4,581	4,581	4,581	4,581	4,581	4,581	4,581	4,581	4,581	4,581	4,581	4,581	4,581	3,436	3,436	3,436	3,436	2,291	2,291	2,291	2,291	2,291	2,291	1,145	1,145	1,145	458
Truck Crane - Greater than 300 ton	0	0	0	0	0	0	0	0	0	0	0	783	783	783	783	783	1,565	1,565	2,348	2,348	3,130	3,130	3,130	3,130	3,130	3,130	3,130	3,130	3,130	2,348	2,348	1,565	1,565	1,565	783	783	783	783	783	0	0	0	0	0	0	0	0	0	0
Truck Crane - Greater than 200 ton	0	0	0	0	0	0	0	0	0	0	0	0	0	0	486	486	486	486	486	973	973	973	1,459	1,459	1,459	1,459	1,459	1,459	1,459	973	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vibratory Roller Ingersol-Rand 20 ton	1,405	1,405	1,405	1,405	1,405	1,405	1,405	1,405	1,405	937	937	937	937	937	468	468	468	468	0	0	0	0	0	0	0	0	0	937	937	937	937	0	0	0	0	0	0	468	468	468	468	0	0	0	0	0	0	0	0
WORKER VEHICLES																																																	
Personal commuting vehicles	15.0	25.8	34.6	44.7	65.6	82.9	98.8	132.8	147.6	177.8	220.4	246.4	292.0	342.5	412.3	465.9	508.5	539.7	568.2	601.9	631.2	706.4	759.3	816.5	868.4	878.6	966.0	1,034.4	1,068.0	1,073.9	1,084.5	1,068.8	1,059.0	1,011.4	957.4	927.3	842.7	815.4	692.0	562.4	445.6	303.1	242.0	241.5	241.5	223.5	189.5	173.7	130.9
DELIVERY TRUCKS																																																	
Light delivery truck (e.g. Fed-Ex)	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Heavy delivery truck (e.g. flat beds carrying construction eqp)	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8	425.8
Import fill trucks	2,043.7	2,043.7	2,043.7	2,043.7	2,043.7	2,043.7	2,043.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ONSITE TOTAL (lbs/day)	**32,197**	**32,930**	**38,023**	**37,949**	**36,661**	**39,382**	**33,604**	**27,509**	**25,471**	**25,062**	**26,515**	**26,800**	**27,512**	**29,178**	**30,294**	**31,587**	**33,975**	**35,073**	**35,110**	**38,528**	**39,340**	**38,840**	**40,412**	**42,960**	**42,032**	**40,439**	**38,775**	**41,757**	**41,362**	**38,946**	**37,148**	**33,592**	**32,555**	**31,582**	**28,832**	**26,280**	**26,137**	**27,327**	**25,560**	**21,538**	**18,233**	**17,622**	**10,207**	**10,206**	**9,234**	**6,917**	**5,927**	**5,350**	**3,884**
OFF-SITE																																																	
WORKER VEHICLES																																																	
Personal commuting vehicles	871.8	1,501.4	2,014.3	2,600.8	3,816.8	4,822.4	5,750.7	7,724.7	8,589.0	######	######	######	######	######	######	######	29,582.9	######	######	######	######	######	######	######	50,520.9	######	56,199.9	60,176.9	62,132.5	62,479.6	63,095.0	62,181.3	61,612.0	######	######	######	######	######	######	######	######	######	######	######	######	######	######	######	7,615.6
DELIVERY TRUCKS																																																	
Light delivery truck (e.g. Fed-Ex)	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2	465.2
Heavy delivery truck (e.g. flat beds carrying construction eqp)	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0	7,256.0
Import fill trucks	22,921.5	######	######	######	######	######	######	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LINEARS																																																	
ON ROAD																																																	
Dump Truck	0	0	0	0	0	0	0	0	0	0	1,151	1,151	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,151	1,151	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Service Truck (MHD-DSL)	0	0	0	0	0	0	0	0	0	0	575	575	575	575	575	575	863	863	863	863	863	863	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pipe Haul Truck and Trailer (HHDT-DSL)	0	0	0	0	0	0	0	0	0	0	863	863	863	863	863	863	575	575	575	575	575	575	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3/4 Ton Pickup (MHD-DSL)	0	0	0	0	0	0	0	0	0	0	1,376	1,376	1,376	1,376	1,376	1,376	2,064	2,064	2,064	2,064	2,064	2,064	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck - water	0	0	0	0	0	0	0	0	0	0	575	575	1,151	1,151	1,151	1,151	1,151	1,151	1,151	1,151	575	575	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF ROAD																																																	
Air Compressor (185 CFM)	0	0	0	0	0	0	0	0	0	0	217	217	434	434	651	651	651	651	434	434	217	217	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bore Machine (Hydraulic)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	234	234	234	234	234	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 Ton Hydra Crane	0	0	0	0	0	0	0	0	0	0	973	1,946	1,946	2,919	2,919	2,919	2,919	2,919	2,919	2,919	1,946	1,946	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Backhoe/loader	0	0	0	0	0	0	0	0	0	0	1,457	1,457	2,429	2,429	2,429	2,429	2,429	2,429	2,429	2,429	1,457	1,457	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator - Trencher	0	0	0	0	0	0	0	0	0	0	0	430	430	430	430	430	430	430	430	430	430	430	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Forklift	0	0	0	0	0	0	0	0	0	0	90	90	179	179	179	179	179	179	179	179	179	90	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Welding Generator	0	0	0	0	0	0	0	0	0	0	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 to 5 Ton AC Roller	0	0	0	0	0	0	0	0	0	0	0	303	303	303	303	303	303	303	303	303	303	303	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pipe Bending Machine	0	0	0	0	0	0	0	0	0	0	351	351	701	701	701	701	701	701	701	351	351	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL																																																	
AIR COMPRESSOR 185	0	0	0	0	0	0	0	0	0	0	0	0	0	217	217	217	217	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BOOM TRUCK 12 TON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	288	288	288	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT 325 BACKHOE	0	0	0	0	0	0	0	0	0	0	0	0	472	472	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT 330 BACKHOE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	799	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT DOZER D-6	0	0	0	0	0	0	0	0	0	0	0	0	1,432	1,432	0	0	716	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT MODEL 12 MOTOR GRADER	0	0	0	0	0	0	0	0	0	0	0	0	864	864	432	432	432	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT ROLLER-COMPACTOR 563	0	0	0	0	0	0	0	0	0	0	0	0	680	680	340	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT RUBBER TIRE LOADER 966	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,610	1,610	1,610	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT SCRAPER 615	0	0	0	0	0	0	0	0	0	0	0	0	2,768	1,384	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CRANE-ROUGH TERRAIN 45T	0	0	0	0	0	0	0	0	0	0	0	0	0	346	346	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENSET 5KW	0	0	0	0	0	0	0	0	0	0	0	0	0	303	151	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
JOHN DEERE TRACTOR 9400	0	0	0	0	0	0	0	0	0	0	0	0	1,604	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PICK-UP CRAFT	0	0	0	0	0	0	0	0	0	0	0	0	4,730	4,730	4,730	4,730	4,730	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PICK-UP OVERHEAD	0	0	0	0	0	0	0	0	0	0	0	0	1,322	3,965	3,965	3,304	3,304	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL BALLAST REGULATOR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	661	661	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL CLIP MACHINE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	174	174	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL MOVER-SHUTTLE WAGON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	661	661	661	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL TAMPER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	661	661	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAIL WELDER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	102	51	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RAMEX WALK BEHIND COMPACTOR	0	0	0	0	0	0	0	0	0	0	0	0	0	19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TRI-AXLE DUMP TRUCK	0	0	0	0	0	0	0	0	0	0	0	0	1,151	1,726	575	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TRUCK FLATBED 14 FOOT	0	0	0	0	0	0	0	0	0	0	0	0	288	288	863	863	863	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TRUCK TRACTOR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,117	1,117	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WATER TRUCK, 4M ON-ROAD	0	0	0	0	0	0	0	0	0	0	0	0	288	288	288	288	288	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WELDING MACHINE 350 AMP	0	0	0	0	0	0	0	0	0	0	0	0	51	51	51	51	51	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LINEARS TOTAL (lbs/day)	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**9,460**	**11,166**	**29,595**	**31,683**	**31,804**	**30,529**	**30,765**	**16,058**	**15,841**	**15,256**	**11,944**	**11,503**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
OFFSITE VEHICLES TOTAL (lbs/day)	**31,515**	**32,144**	**32,657**	**33,244**	**34,460**	**35,465**	**36,393**	**15,446**	**16,310**	**18,063**	**20,545**	**22,058**	**24,710**	**27,647**	**31,708**	**34,827**	**37,304**	**39,117**	**40,776**	**42,741**	**44,443**	**48,816**	**51,893**	**55,226**	**58,242**	**58,838**	**63,921**	**67,898**	**69,854**	**70,201**	**70,816**	**69,903**	**69,333**	**66,564**	**63,420**	**61,669**	**56,748**	**55,158**	**47,979**	**40,440**	**33,645**	**25,358**	**21,799**	**21,773**	**21,773**	**20,722**	**18,747**	**17,824**	**15,337**
TOTAL PROJECT (lbs/day)	63,712	65,075	70,680	71,192	71,120	74,847	69,997	42,955	41,782	43,125	56,520	60,024	81,817	88,508	93,806	96,943	102,044	90,249	91,727	96,525	95,727	99,159	92,305	98,187	100,274	99,277	102,696	109,655	111,216	109,147	107,965	103,494	101,888	98,146	92,252	87,949	82,885	82,486	73,539	61,978	51,878	42,980	32,005	31,979	31,007	27,638	24,674	23,174	19,221

Notes:

1. According to schedules provided by Fluor, Linear construction (except rail) takes place in months 11-22.
2. According to schedules provided by Fluor, Rail construction occurs in months 13-17.

Hydrogen Energy California, Kern County Power Project
PM10 Emissions by Month - from Fugitive Sources
8/14/2012

PM10 - Fugitives

MONTHLY EMISSIONS (lbs/day)

CONSTRUCTION VEHICLES	Round Trips per day per unit	Round Trip Distance (miles/vehicle/ day)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
ON-SITE																																																			
On-Road Vehicles																																																			
18 cy fill mat'l haul truck	1	1.8	0.0	0.0	1.5	1.4	2.7	2.7	2.6	1.9	0.9	0.9	0.8	0.8	0.4	0.4	0.4	0.4	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bus	1	0.75	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.0	0.0
Concrete Pumper Truck	2	0.75	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dump Truck	8	0.75	1.5	2.0	2.0	1.4	1.4	1.3	1.3	0.9	0.9	0.9	0.6	0.6	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.6	0.7	0.7	0.5	0.2	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0
Diesel Tractor (Yard Dog)	2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Service Truck - 1 ton	10	0.5	0.9	0.8	0.8	1.6	1.5	1.5	1.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Pile Driver Truck	2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck - Fuel/Lube	8	0.75	1.0	1.0	1.0	0.9	0.9	0.9	0.9	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.0	0.0	0.0
Tractor Truck 5th Wheel	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trucks - Pickup 3/4 ton	10	0.5	2.1	2.1	2.0	2.0	1.9	2.2	2.5	2.1	3.7	3.5	3.5	3.5	5.5	5.4	5.4	5.2	5.2	5.2	5.1	5.2	5.1	5.0	5.0	4.9	4.9	4.8	4.7	4.7	4.6	4.5	4.5	4.4	4.4	4.4	4.4	4.4	4.5	4.5	4.6	4.7	4.8	5.2	3.1	3.1	2.1	2.1	2.1	2.2	1.2
Trucks - 3 ton	2	0.5	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck - Water	4	1	1.7	1.7	1.6	1.6	1.5	1.5	0.9	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.3	0.5	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Off Road Vehicles																																																			
Air Compressor 185 CFM	1	0.01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Air Compressor 750 CFM	1	0.01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Articulating Boom Platform	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bob cat loader	0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bulldozer D10R	0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bulldozer D6C	0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Concrete Trowel Machine	1	0.25	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Concrete Vibrators	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cranes - Mobile 35 ton	1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cranes - Mobile 45 ton	1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Crane - Mobile 65 ton	1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cranes 100 / 150 ton cap	1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Diesel Powered Welder	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Backhoe/loader	0	0.25	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Earth Scraper 637	0	0.909	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - loader	0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Motor Grader (CAT140H)	0	1.439	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Trencher (CAT320)	0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fired Heaters (2,000 BTU)	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Forklift	5	0.5	1.3	1.2	1.2	1.2	1.1	1.1	1.1	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.6	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.2	0.2	0.2	0.2	0.1	0.1	0.1
Fusion Welder	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Haul / 600 tn Crane	1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Haul / 1,000 tn Crane	1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Light Plants	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Man lifts - telescoping	1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Man lift - scissor	1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Compaction Roller	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Compaction - Vibratory Plate	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Compaction - Ram	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumps	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Power Generators	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck Crane - Greater than 300 ton	1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck Crane - Greater than 200 ton	1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Vibratory Roller Ingersol-Rand 20 ton	2	0.25	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WORKER VEHICLES																																																			
Personal commuting vehicles			0.5	0.8	1.1	1.4	1.9	2.4	2.8	2.6	2.8	3.2	3.9	4.4	4.9	5.7	6.8	7.5	8.1	8.6	9.0	9.6	10.0	10.9	11.6	12.3	13.0	13.0	14.0	14.8	15.1	15.0	14.9	14.6	14.4	13.8	13.0	12.6	11.6	11.3	9.8	8.1	6.6	4.8	3.9	3.9	3.9	3.6	3.1	2.9	2.3
DELIVERY TRUCKS																																																			
Light delivery truck (e.g. Fed-Ex)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy delivery truck (e.g. flat beds carrying construction eqp)			2.1	2.1	2.1	2.0	1.9	1.9	1.8	1.3	1.2	1.2	1.2	1.2	1.1	1.1	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.2
Import fill trucks			91.0	88.7	87.1	84.0	81.1	79.0	77.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CONSTRUCTION ACTIVITY																																																			
Dirt Piling - Bob cat loader			0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.1	0.1	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dirt Piling - Trencher (CAT320)			0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dirt Piling - Backhoe/loader			0.2	0.2	0.2	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dirt Piling - loader			0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grading - Earth Scraper 637			54.7	54.7	54.7	54.7	47.4	47.4	42.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grading - Motor Grader (CAT140H)			0.0	9.9	9.9	9.9	29.8	29.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.9	9.9	9.9	9.9	0.0	0.0	0.0	0.0	19.9	19.9	19.9	19.9	9.9	9.9	9.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bulldozing - Bulldozer D10R			77.4	77.4	77.4	51.6	51.6	51.6	51.6	51.6	51.6	25.8	25.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bulldozing - Bulldozer D6C			77.4	77.4	77.4	77.4	51.6	51.6	51.6	51.6	51.6	51.6	25.8	25.8	25.8	25.8	25.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.8	25.8	25.8	25.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Covered Storage Piles			0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5																																									
ONSITE TOTAL (lbs/day)			**312.9**	**321.1**	**321.0**	**292.2**	**277.6**	**276.4**	**240.2**	**116.0**	**116.0**	**90.4**	**64.9**	**39.6**	**41.7**	**42.4**	**43.3**	**17.5**	**18.3**	**18.8**	**18.7**	**19.5**	**19.9**	**20.4**	**21.0**	**21.7**	**22.0**	**21.8**	**22.5**	**59.8**	**59.9**	**59.7**	**59.4**	**22.8**	**22.7**	**22.0**	**21.1**	**41.1**	**40.4**	**40.2**	**38.7**	**26.6**	**25.0**	**23.7**	**9.3**	**9.3**	**8.2**	**7.7**	**6.9**	**6.8**	**5.3**
OFF-SITE																																																			
WORKER VEHICLES																																																			
Personal commuting vehicles			0.2	0.3	0.4	0.5	0.7	0.8	1.0	1.4	1.5	1.8	2.2	2.5	3.0	3.5	4.2	4.8	5.2	5.5	5.8	6.1	6.4	7.2	7.7	8.3	8.9	9.0	9.8	10.5	10.9	11.0	11.1	10.9	10.8	10.3	9.8	9.5	8.6	8.3	7.1	5.7	4.5	3.1	2.5	2.5	2.5	2.3	1.9	1.8	1.3
DELIVERY TRUCKS																																																			
Light delivery truck (e.g. Fed-Ex)			0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Heavy delivery truck (e.g. flat beds carrying construction eqp)			3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Import fill trucks			10.4	10.4	10.4	10.4	10.4	10.4	10.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LINEARS																																																			
ON ROAD																																																			
Dump Truck			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.8	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	0.8	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Service Truck (MHD-DSL)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipe Haul Truck and Trailer (HHDT-DSL)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3/4 Ton Pickup (MHD-DSL)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck - water			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OFF ROAD																																																			
Air Compressor (185 CFM)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bore Machine (Hydraulic)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12 Ton Hydra Crane			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Backhoe/loader			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Trencher			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Forklift			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Welding Generator			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3 to 5 Ton AC Roller			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipe Bending Machine			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CONSTRUCTION ACTIVITY																																																			
Dirt piling - Backhoe			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.4	0.3	0.3	0.3	0.4	0.3	0.4	0.4	0.4	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dirt piling - Excavator			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dirt piling - CAT 325 BACKHOE			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dirt piling - CAT 330 BACKHOE			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dirt piling - CAT DOZER D-6			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dirt piling - CAT RUBBER TIRE LOADER 966			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grading - CAT MODEL 12 MOTOR GRADER			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.9	19.9	9.9	9.9	9.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grading - CAT SCRAPER 615			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	120.7	60.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Storage Piles													0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2																											
RAIL																																																			
AIR COMPRESSOR 185			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BOOM TRUCK 12 TON			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT 325 BACKHOE			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT 330 BACKHOE			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT DOZER D-6			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT MODEL 12 MOTOR GRADER			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT ROLLER-COMPACTOR 563			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT RUBBER TIRE LOADER 966			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT SCRAPER 615			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CRANE-ROUGH TERRAIN 45T			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GENSET 5KW			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
JOHN DEERE TRACTOR 9400			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PICK-UP CRAFT			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PICK-UP OVERHEAD			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.0	1.0	0.8	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL BALLAST REGULATOR			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL CLIP MACHINE			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL MOVER-SHUTTLE WAGON			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL TAMPER			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL WELDER			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAMEX WALK BEHIND COMPACTOR			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRI-AXLE DUMP TRUCK			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.2	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRUCK FLATBED 14 FOOT			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRUCK TRACTOR			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WATER TRUCK, 4M ON-ROAD			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WELDING MACHINE 350 AMP			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LINEARS TOTAL (lbs/day)			**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**2.7**	**3.2**	**147.4**	**88.3**	**18.0**	**17.4**	**17.4**	**4.7**	**4.7**	**4.7**	**3.7**	**3.4**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
OFFSITE VEHICLES TOTAL (lbs/day)			**14.2**	**14.3**	**14.4**	**14.5**	**14.7**	**14.8**	**15.0**	**5.0**	**5.1**	**5.4**	**5.9**	**6.1**	**6.6**	**7.1**	**7.8**	**8.4**	**8.8**	**9.1**	**9.4**	**9.8**	**10.1**	**10.8**	**11.4**	**11.9**	**12.5**	**12.6**	**13.5**	**14.2**	**14.5**	**14.6**	**14.7**	**14.5**	**14.4**	**13.9**	**13.4**	**13.1**	**12.2**	**11.9**	**10.7**	**9.4**	**8.2**	**6.7**	**6.1**	**6.1**	**6.1**	**5.9**	**5.6**	**5.4**	**5.0**
TOTAL PROJECT (lbs/day)			327.1	335.3	335.4	306.7	292.3	291.2	255.2	120.9	121.2	95.8	73.4	48.9	195.6	137.8	69.2	43.2	44.5	32.6	32.8	33.9	33.6	34.6	32.4	33.6	34.5	34.3	35.9	74.0	74.4	74.2	74.1	37.3	37.1	35.9	34.5	54.2	52.6	52.1	49.4	36.0	33.1	30.4	15.4	15.4	14.3	13.6	12.5	12.2	10.2

Notes:

1. According to schedules provided by Fluor, Linear construction (except rail) takes place in months 11-22.
2. According to schedules provided by Fluor, Rail construction occurs in months 13-17.
3. According to schedule on "onsite equipment" tab, site prep/pilling occurs in months 1-8. Assume onsite covered storage piles are only present during these months.
4. Assume linear covered storage piles are present during entire 12 months of linear construction, months 11-22.

Hydrogen Energy California, Kern County Power Project
PM2.5 Emissions by Month - from Fugitive Sources
8/14/2012

PM2.5 - Fugitives

MONTHLY EMISSIONS (lbs/day)

CONSTRUCTION VEHICLES	Round Trips per day per unit	Round Trip Distance (miles/vehicle/day)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
ON-SITE																																																			
On-Road Vehicles																																																			
18 cy fill mat'l haul truck	1	1.8	0.0	0.0	0.1	0.1	0.3	0.3	0.3	0.2	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bus	1	0.75	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Concrete Pumper Truck	2	0.75	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dump Truck	8	0.75	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Diesel Tractor (Yard Dog)	2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Service Truck - 1 ton	10	0.5	0.1	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pile Driver Truck	2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck - Fuel/Lube	8	0.75	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tractor Truck 5th Wheel	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trucks - Pickup 3/4 ton	10	0.5	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.4	0.4	0.3	0.3	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.3	0.3	0.2	0.2	0.2	0.2	0.1
Trucks - 3 ton	2	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck - Water	4	1	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Off Road Vehicles																																																			
Air Compressor 185 CFM	1	0.01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Air Compressor 750 CFM	1	0.01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Articulating Boom Platform	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bob cat loader	0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bulldozer D10R	0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bulldozer D6C	0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Concrete Trowel Machine	1	0.25	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Concrete Vibrators	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cranes - Mobile 35 ton	1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cranes - Mobile 45 ton	1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Crane - Mobile 65 ton	1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cranes 100 / 150 ton cap	1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Diesel Powered Welder	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Backhoe/loader	0	0.25	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Earth Scraper 637	0	0.909	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - loader	0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Motor Grader (CAT140H)	0	1.439	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Trencher (CAT320)	0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fired Heaters (2,000 BTU)	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Forklift	5	0.5	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fusion Welder	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Haul / 600 tn Crane	1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Haul / 1,000 tn Crane	1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Light Plants	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Man lifts - telescoping	1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Man lift - scissor	1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Compaction Roller	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Compaction - Vibratory Plate	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Compaction - Ram	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumps	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portable Power Generators	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck Crane - Greater than 300 ton	1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck Crane - Greater than 200 ton	1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Vibratory Roller Ingersol-Rand 20 ton	2	0.25	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WORKER VEHICLES																																																			
Personal commuting vehicles			0.0	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.4	0.5	0.6	0.7	0.7	0.8	0.9	0.9	1.0	1.0	1.1	1.2	1.2	1.3	1.3	1.4	1.5	1.5	1.5	1.5	1.5	1.4	1.4	1.3	1.3	1.2	1.1	1.0	0.8	0.7	0.5	0.4	0.4	0.4	0.4	0.3	0.3	0.2
DELIVERY TRUCKS																																																			
Light delivery truck (e.g. Fed-Ex)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy delivery truck (e.g. flat beds carrying construction eqp)			0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Import fill trucks			9.2	9.0	8.8	8.5	8.2	8.0	7.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CONSTRUCTION ACTIVITY																																																			
Dirt Piling - Bob cat loader			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dirt Piling - Trencher (CAT320)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dirt Piling - Backhoe/loader			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dirt Piling - loader			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grading - Earth Scraper 637			10.5	10.5	10.5	10.5	9.4	9.4	8.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grading - Motor Grader (CAT140H)			0.0	0.9	0.9	0.9	2.8	2.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	0.9	0.9	0.9	0.0	0.0	0.0	0.0	1.9	1.9	1.9	1.9	0.9	0.9	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bulldozing - Bulldozer D10R			25.6	25.6	25.6	17.1	17.1	17.1	17.1	17.1	17.1	8.5	8.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bulldozing - Bulldozer D6C			25.6	25.6	25.6	25.6	17.1	17.1	17.1	17.1	17.1	17.1	8.5	8.5	8.5	8.5	8.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.5	8.5	8.5	8.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Covered Storage Piles			0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1																																									
ONSITE TOTAL (lbs/day)			**72.4**	**73.1**	**73.1**	**64.3**	**56.3**	**56.2**	**52.4**	**35.5**	**35.5**	**27.0**	**18.5**	**10.0**	**10.2**	**10.2**	**10.3**	**1.8**	**1.9**	**1.9**	**1.9**	**2.0**	**2.0**	**2.1**	**2.1**	**2.2**	**2.2**	**2.2**	**2.3**	**11.9**	**11.9**	**11.9**	**11.9**	**2.3**	**2.3**	**2.2**	**2.1**	**4.0**	**4.0**	**4.0**	**3.8**	**2.6**	**2.5**	**2.4**	**0.9**	**0.9**	**0.8**	**0.8**	**0.7**	**0.7**	**0.5**
OFF-SITE																																																			
WORKER VEHICLES																																																			
Personal commuting vehicles			0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.4	0.4	0.6	0.6	0.7	0.9	1.0	1.2	1.3	1.4	1.4	1.5	1.6	1.8	1.9	2.0	2.2	2.2	2.4	2.6	2.7	2.7	2.7	2.7	2.7	2.5	2.4	2.3	2.1	2.0	1.7	1.4	1.1	0.8	0.6	0.6	0.6	0.6	0.5	0.4	0.3
DELIVERY TRUCKS																																																			
Light delivery truck (e.g. Fed-Ex)			0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Heavy delivery truck (e.g. flat beds carrying construction eqp)			0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Import fill trucks			2.5	2.5	2.5	2.5	2.5	2.5	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LINEARS																																																			
ON ROAD																																																			
Dump Truck			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Service Truck (MHD-DSL)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipe Haul Truck and Trailer (HHDT-DSL)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3/4 Ton Pickup (MHD-DSL)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Truck - water			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OFF ROAD																																																			
Air Compressor (185 CFM)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bore Machine (Hydraulic)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12 Ton Hydra Crane			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Backhoe/loader			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excavator - Trencher			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Forklift			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Welding Generator			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3 to 5 Ton AC Roller			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipe Bending Machine			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CONSTRUCTION																																																			
Dirt piling - Backhoe			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dirt piling - Excavator			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dirt piling - CAT 325 BACKHOE			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dirt piling - CAT 330 BACKHOE			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dirt piling - CAT DOZER D-6			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dirt piling - CAT RUBBER TIRE LOADER 966			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grading - CAT MODEL 12 MOTOR GRADER			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	1.9	0.9	0.9	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grading - CAT SCRAPER 615			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.2	12.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Storage Piles													0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0																											
RAIL																																																			
AIR COMPRESSOR 185			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BOOM TRUCK 12 TON			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT 325 BACKHOE			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT 330 BACKHOE			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT DOZER D-6			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT MODEL 12 MOTOR GRADER			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT ROLLER-COMPACTOR 563			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT RUBBER TIRE LOADER 966			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT SCRAPER 615			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CRANE-ROUGH TERRAIN 45T			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GENSET 5KW			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
JOHN DEERE TRACTOR 9400			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PICK-UP CRAFT			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PICK-UP OVERHEAD			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL BALLAST REGULATOR			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL CLIP MACHINE			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL MOVER-SHUTTLE WAGON			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL TAMPER			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAIL WELDER			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RAMEX WALK BEHIND COMPACTOR			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRI-AXLE DUMP TRUCK			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRUCK FLATBED 14 FOOT			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRUCK TRACTOR			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WATER TRUCK, 4M ON-ROAD			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WELDING MACHINE 350 AMP			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LINEARS TOTAL (lbs/day)			**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.3**	**0.4**	**27.8**	**15.3**	**1.8**	**1.7**	**1.7**	**0.5**	**0.5**	**0.5**	**0.4**	**0.4**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
OFFSITE VEHICLES TOTAL (lbs/day)			**3.5**	**3.5**	**3.5**	**3.5**	**3.6**	**3.6**	**3.7**	**1.2**	**1.3**	**1.3**	**1.4**	**1.5**	**1.6**	**1.7**	**1.9**	**2.1**	**2.2**	**2.2**	**2.3**	**2.4**	**2.5**	**2.7**	**2.8**	**2.9**	**3.1**	**3.1**	**3.3**	**3.5**	**3.6**	**3.6**	**3.6**	**3.6**	**3.5**	**3.4**	**3.3**	**3.2**	**3.0**	**2.9**	**2.6**	**2.3**	**2.0**	**1.6**	**1.5**	**1.5**	**1.5**	**1.4**	**1.4**	**1.3**	**1.2**
TOTAL PROJECT (lbs/day)			75.9	76.6	76.7	67.8	59.9	59.8	56.1	36.8	36.8	28.3	20.2	11.8	39.6	27.3	14.0	5.6	5.8	4.7	4.7	4.9	4.9	5.1	4.9	5.1	5.3	5.3	5.6	15.4	15.5	15.5	15.5	5.8	5.8	5.6	5.4	7.3	7.0	6.9	6.4	4.9	4.5	4.0	2.4	2.4	2.3	2.2	2.1	2.0	1.8

Notes:

1. According to schedules provided by Fluor, Linear construction (except rail) takes place in months 11-22.
2. According to schedules provided by Fluor, Rail construction occurs in months 13-17.
3. According to schedule on "onsite equipment" tab, site prep/pilling occurs in months 1-8. Assume covered storage piles are only present during these months.
4. Assume linear covered storage piles are present during entire 12 months of linear construction, months 11-22.

Hydrogen Energy California, Kern County Power Project

Calculation of maximum short-term (daily) and annual emissions
1/29/2013

PROJECT MONTHLY EMISSIONS (lbs/month)

PROJECT EMISSIONS (on-site + linears)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
CO	3,222	3,320	3,952	3,991	4,067	4,408	3,847	3,371	3,186	3,290	4,650	4,916	6,641	7,324	7,225	7,394	7,670	6,382	6,299	6,551	6,233	6,091	4,903	5,250	5,061	4,949	4,808
CO2	703,040	719,044	830,245	828,597	800,494	859,890	733,697	600,356	555,736	546,695	784,578	827,886	1,247,557	1,329,371	1,356,321	1,356,399	1,413,544	1,114,617	1,110,530	1,172,230	1,117,660	1,097,139	880,652	936,225	916,053	881,339	845,114
CH4	62	64	73	73	70	75	63	58	57	61	87	94	127	139	139	147	150	127	127	133	128	125	104	111	106	103	100
N2O	13	13	15	15	15	16	14	12	11	11	16	17	20	21	22	23	24	25	25	27	25	25	20	21	21	20	19
NOx	6,550	6,711	7,829	7,819	7,657	8,282	7,121	5,796	5,326	5,286	7,469	7,879	11,316	12,114	12,101	12,084	12,612	10,347	10,259	10,813	10,275	10,061	8,056	8,590	8,374	8,080	7,745
PM10 - comb + fug	7,221.8	7,413.3	7,493.2	6,865.3	6,567.6	6,585.6	5,730.2	2,936.5	2,909.3	2,359.4	1,999.4	1,483.1	4,881.1	3,659.0	2,114.3	1,538.6	1,582.8	1,198.5	1,183.4	1,230.8	1,179.8	1,169.4	977.7	1,030.5	1,016.7	999.7	997.4
PM2.5 - comb + fug	1,901.6	1,929.5	2,002.5	1,813.0	1,658.9	1,696.9	1,560.1	1,133.5	1,106.3	931.6	880.7	721.0	1,494.2	1,278.1	965.4	783.0	807.2	675.8	664.6	693.9	658.0	644.9	517.7	553.8	535.2	523.5	508.9
SO2	7	7	8	8	8	9	8	6	6	6	9	9	14	14	15	15	15	12	12	13	12	12	10	10	10	10	9
ROG	1,017	1,046	1,268	1,289	1,384	1,507	1,350	1,134	1,032	1,076	1,511	1,615	2,074	2,240	2,228	2,264	2,361	2,047	1,986	2,095	1,985	1,932	1,574	1,715	1,669	1,630	1,589
CO2e	708,343	724,467	836,506	834,869	806,541	866,396	739,285	605,201	560,370	551,369	791,452	835,251	1,256,345	1,338,945	1,366,145	1,366,549	1,424,275	1,124,895	1,120,929	1,183,254	1,128,243	1,107,556	889,059	945,130	924,702	889,662	853,056

12-month Rolling Emissions (tons/yr)

PROJECT EMISSIONS (on-site + linears)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
CO	-	-	-	-	-	-	-	-	-	-	-	23	25	27	28	30	32	33	34	36	37	39	39	38.98	38.19	37.00	36
CO2	-	-	-	-	-	-	-	-	-	-	-	4395	4667	4973	5236	5499	5806	5933	6122	6408	6689	6964	7012	7066	6900	6676	6421
CH4	-	-	-	-	-	-	-	-	-	-	-	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1
N2O	-	-	-	-	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NOx	-	-	-	-	-	-	-	-	-	-	-	42	44	47	49	51	54	55	56	59	61	64	64	64	63	61	59
PM10 - comb + fug	-	-	-	-	-	-	-	-	-	-	-	29.8	28.6	26.7	24.0	21.4	18.9	16.2	13.9	13.1	12.2	11.6	11.1	10.9	8.9	7.6	7.1
PM2.5 - comb + fug	-	-	-	-	-	-	-	-	-	-	-	8.7	8.5	8.1	7.6	7.1	6.7	6.2	5.7	5.5	5.3	5.1	5.0	4.9	4.4	4.0	3.8
SO2	-	-	-	-	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ROG	-	-	-	-	-	-	-	-	-	-	-	8	8	9	9	10	10	10	11	11	12	12	12.20	12.25	12.05	11.74	11.42
CO2e	-	-	-	-	-	-	-	-	-	-	-	4430	4704	5011	5276	5542	5851	5980	6171	6460	6744	7022	7071	7126	6960	6735	6479

Construction days per month: 22

ONSITE MONTHLY EMISSIONS (lbs/month)

ONSITE EMISSIONS (no linears)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
CO	3,222	3,320	3,952	3,991	4,067	4,408	3,847	3,371	3,186	3,290	3,411	3,481	3,491	3,759	3,822	4,078	4,251	4,317	4,291	4,653	4,706	4,659	4,903	5,250	5,061	4,949	4,808
CO2	703,040	719,044	830,245	828,597	800,494	859,890	733,697	600,356	555,736	546,695	578,374	584,527	600,074	636,327	660,620	688,647	740,771	764,687	765,299	839,744	857,402	846,445	880,652	936,225	916,053	881,339	845,114
CH4	62	64	73	73	70	75	63	58	57	61	63	64	63	69	71	80	82	84	86	95	96	96	104	111	106	103	100
N2O	13	13	15	15	15	16	14	12	11	11	12	12	12	13	14	15	16	17	17	19	20	19	20	21	21	20	19
NOx	6,550	6,711	7,829	7,819	7,657	8,282	7,121	5,796	5,326	5,286	5,545	5,616	5,694	6,058	6,254	6,503	6,914	7,105	7,066	7,732	7,867	7,742	8,056	8,590	8,374	8,080	7,745
PM10 - comb + fug	7,221.8	7,413.3	7,493.2	6,865.3	6,567.6	6,585.6	5,730.2	2,936.5	2,909.3	2,359.4	1,807.6	1,259.4	1,303.6	1,349.1	1,373.9	826.9	860.7	878.0	867.9	922.9	936.3	940.3	977.7	1,030.5	1,016.7	999.7	997.4
PM2.5 - comb + fug	1,901.6	1,929.5	2,002.5	1,813.0	1,658.9	1,696.9	1,560.1	1,133.5	1,106.3	931.6	752.5	573.0	576.0	604.8	611.2	443.5	458.3	465.6	459.0	495.2	500.6	494.8	517.7	553.8	535.2	523.5	508.9
SO2	7	7	8	8	8	9	8	6	6	6	6	6	6	7	7	8	8	8	8	9	9	9	10	10	10	10	9
ROG	1,017	1,046	1,268	1,289	1,384	1,507	1,350	1,134	1,032	1,076	1,112	1,156	1,117	1,200	1,220	1,295	1,386	1,405	1,365	1,499	1,514	1,488	1,574	1,715	1,669	1,630	1,589
CO2e	708,343	724,467	836,506	834,869	806,541	866,396	739,285	605,201	560,370	551,369	583,325	589,594	605,257	641,919	666,468	694,913	747,446	771,617	772,428	847,622	865,481	854,479	889,059	945,130	924,702	889,662	853,056

12-month Rolling Emissions (tons/yr)

ONSITE EMISSIONS (no linears)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
CO	-	-	-	-	-	-	-	-	-	-	-	22	22	22	22	22	22	22	22	23	24	24	25	26.09	26.88	27.47	28
CO2	-	-	-	-	-	-	-	-	-	-	-	4170	4119	4078	3993	3923	3893	3845	3861	3981	4132	4281	4433	4608	4766	4889	4981
CH4	-	-	-	-	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1
N2O	-	-	-	-	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NOx	-	-	-	-	-	-	-	-	-	-	-	40	39	39	38	38	37	37	37	38	39	40	41	43	44	45	46
PM10 - comb + fug	-	-	-	-	-	-	-	-	-	-	-	29.6	26.6	23.6	20.5	17.5	14.7	11.8	9.4	8.4	7.4	6.7	6.2	6.1	6.0	5.8	5.6
PM2.5 - comb + fug	-	-	-	-	-	-	-	-	-	-	-	8.5	7.9	7.2	6.5	5.8	5.2	4.6	4.1	3.7	3.4	3.2	3.1	3.1	3.1	3.0	3.0
SO2	-	-	-	-	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ROG	-	-	-	-	-	-	-	-	-	-	-	7	7	7	7	7	7	7	7	7	8	8	8.11	8.39	8.66	8.88	9.06
CO2e	-	-	-	-	-	-	-	-	-	-	-	4203	4152	4110	4025	3955	3926	3878	3895	4016	4169	4320	4473	4651	4811	4935	5028

Construction days per month: 22

TOTAL MONTHLY EMISSIONS (lbs/month)

TOTAL EMISSIONS (onsite + linears + offsite)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
CO	4,744	4,949	5,670	5,809	6,092	6,606	6,204	5,032	4,995	5,399	7,183	7,708	9,887	11,073	11,669	12,372	13,072	12,094	12,295	12,883	12,857	13,463	12,802	13,720	14,046	14,036	14,765
CO2	1,388,652	1,417,953	1,539,984	1,550,723	1,548,297	1,628,932	1,522,341	931,547	905,178	933,158	1,223,453	1,298,709	1,774,386	1,918,227	2,030,943	2,096,875	2,206,334	1,945,691	1,976,634	2,079,830	2,061,216	2,133,033	1,981,527	2,107,495	2,151,011	2,128,874	2,200,002
CH4	98	103	114	118	120	131	123	104	107	120	159	173	220	246	266	289	305	291	299	315	318	338	332	355	365	366	387
N2O	35	37	41	42	45	48	48	36	38	42	54	59	68	77	88	96	104	109	113	120	123	133	136	146	153	153	165
NOx	13,400	13,573	14,702	14,705	14,568	15,213	14,070	7,674	7,222	7,217	9,451	9,892	13,384	14,242	14,312	14,359	14,937	12,709	12,656	13,250	12,747	12,623	10,680	11,282	11,129	10,847	10,616
PM10 - comb + fug	7,779.7	7,974.8	8,057.5	7,433.0	7,142.1	7,165.7	6,315.5	3,119.4	3,097.0	2,556.9	2,210.9	1,703.1	5,116.0	3,910.4	2,388.6	1,830.4	1,888.5	1,514.4	1,508.6	1,567.0	1,525.7	1,539.8	1,365.5	1,437.0	1,440.1	1,426.4	1,452.8
PM2.5 - comb + fug	2,188.8	2,217.9	2,291.9	2,103.4	1,951.6	1,991.5	1,856.4	1,218.5	1,193.0	1,021.5	975.3	818.4	1,596.5	1,386.0	1,080.9	904.3	933.2	805.2	797.1	830.0	797.3	792.4	670.9	713.4	700.3	689.8	684.7
SO2	14	14	15	15	15	16	15	10	9	10	13	14	19	20	21	22	23	20	20	21	21	22	20	21	22	22	22
ROG	1,325	1,358	1,582	1,606	1,708	1,835	1,683	1,250	1,152	1,206	1,653	1,765	2,239	2,420	2,429	2,481	2,591	2,287	2,235	2,354	2,254	2,223	1,881	2,040	2,009	1,974	1,960
CO2e	1,401,665	1,431,640	1,554,962	1,566,229	1,564,651	1,646,631	1,539,941	945,013	919,195	948,761	1,243,445	1,320,527	1,799,966	1,947,183	2,063,732	2,132,741	2,244,965	1,985,469	2,017,996	2,123,550	2,105,997	2,181,504	2,030,702	2,160,109	2,206,028	2,184,092	2,259,321

12-month Rolling Emissions (tons/yr)

TOTAL EMISSIONS (onsite + linears + offsite)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
CO	-	-	-	-	-	-	-	-	-	-	-	35	38	41	44	47	51	53	56	60	64	68	71	74.09	76.17	77.65	79
CO2	-	-	-	-	-	-	-	-	-	-	-	7944	8137	8387	8633	8906	9235	9393	9621	10195	10773	11373	11752	12156	12344	12450	12534
CH4	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2
N2O	-	-	-	-	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1
NOx	-	-	-	-	-	-	-	-	-	-	-	71	71	71	71	71	71	70	69	72	75	77	78	79	77	76	74
PM10 - comb + fug	-	-	-	-	-	-	-	-	-	-	-	32.3	30.9	28.9	26.1	23.3	20.7	17.8	15.4	14.6	13.9	13.4	12.9	12.8	11.0	9.7	9.2
PM2.5 - comb + fug	-	-	-	-	-	-	-	-	-	-	-	9.9	9.6	9.2	8.6	8.0	7.5	6.9	6.4	6.2	6.0	5.9	5.7	5.7	5.2	4.9	4.7
SO2	-	-	-	-	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ROG	-	-	-	-	-	-	-	-	-	-	-	9	10	10	10	11	11	12	12	12	13	13	13.58	13.72	13.60	13.38	13.14
CO2e	-	-	-	-	-	-	-	-	-	-	-	8041	8240	8498	8753	9036	9376	9545	9784	10374	10967	11584	11977	12397	12600	12718	12816

Hydrogen Energy California, Kern County Power Project

Calculation of maximum short-term (daily) and annual emissions
1/29/2013

PROJECT EMISSIONS (on-site + linears)	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
CO	5,185	5,206	4,968	4,840	4,426	4,305	4,173	3,853	3,464	3,485	3,662	3,384	2,860	2,484	2,407	1,437	1,437	1,338	939	800	726	510
CO2	910,216	901,616	849,028	809,862	732,331	709,759	688,585	628,670	573,042	569,938	595,888	557,441	469,766	397,598	384,283	222,503	222,493	201,234	150,808	129,251	116,660	84,708
CH4	106	105	100	96	88	85	82	76	66	66	69	63	51	46	45	30	30	30	18	15	14	9
N2O	20	20	18	17	16	15	15	13	12	12	12	12	10	8	8	5	5	4	3	3	2	2
NOx	8,382	8,324	7,837	7,482	6,761	6,557	6,354	5,780	5,241	5,238	5,511	5,159	4,367	3,691	3,595	2,058	2,058	1,870	1,383	1,188	1,074	795
PM10 - comb + fug	1,863.4	1,870.2	1,837.6	1,817.2	966.8	952.0	923.6	863.8	1,265.2	1,253.6	1,270.4	1,210.6	890.0	810.1	776.6	353.1	353.0	317.6	267.4	236.4	225.0	172.0
PM2.5 - comb + fug	762.2	766.4	740.9	727.3	474.6	463.4	449.3	410.5	418.2	419.5	438.8	411.3	335.5	292.2	284.4	155.7	155.7	143.0	106.1	91.9	84.7	62.6
SO2	10	10	9	9	8	8	7	7	6	6	6	6	5	4	4	2	2	2	2	1	1	1
ROG	1,693	1,688	1,625	1,586	1,480	1,444	1,415	1,322	1,130	1,143	1,181	1,084	911	783	770	458	458	438	304	257	228	172
CO2e	918,660	909,963	856,806	817,263	739,019	716,209	694,806	634,294	578,153	575,014	601,197	562,328	473,842	401,124	387,689	224,549	224,539	203,152	152,170	130,393	117,693	85,447

PROJECT EMISSIONS (on-site + linears)	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
CO	35	33	33	32	31	30	29	29	28	27	26	25	24	23	22	20	18	17	15	14	12	11
CO2	6198	5942	5809	5659	5439	5235	5030	4904	4723	4550	4407	4263	4043	3791	3559	3265	3010	2756	2487	2237	2009	1766
CH4	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0
N2O	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NOx	57	55	53	52	50	48	46	45	43	42	41	39	37	35	33	30	28	25	23	21	19	16
PM10 - comb + fug	7.2	7.4	7.7	8.0	7.9	7.7	7.6	7.6	7.7	7.8	7.9	8.0	7.6	7.0	6.5	5.8	5.5	5.1	4.8	4.5	4.0	3.4
PM2.5 - comb + fug	3.8	3.8	3.8	3.8	3.7	3.6	3.5	3.5	3.4	3.3	3.3	3.2	3.0	2.8	2.6	2.3	2.1	2.0	1.8	1.6	1.5	1.3
SO2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ROG	11.14	10.80	10.59	10.39	10.08	10	10	9	9	9	9	8	8	8	7	7	6	6	5	4	4	4
CO2e	6255	5998	5864	5712	5490	5284	5077	4950	4766	4591	4447	4302	4079	3825	3590	3294	3037	2780	2509	2257	2027	1782

Construction days per month:

ONSITE EMISSIONS (no linears)	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
CO	5,185	5,206	4,968	4,840	4,426	4,305	4,173	3,853	3,464	3,485	3,662	3,384	2,860	2,484	2,407	1,437	1,437	1,338	939	800	726	510
CO2	910,216	901,616	849,028	809,862	732,331	709,759	688,585	628,670	573,042	569,938	595,888	557,441	469,766	397,598	384,283	222,503	222,493	201,234	150,808	129,251	116,660	84,708
CH4	106	105	100	96	88	85	82	76	66	66	69	63	51	46	45	30	30	30	18	15	14	9
N2O	20	20	18	17	16	15	15	13	12	12	12	12	10	8	8	5	5	4	3	3	2	2
NOx	8,382	8,324	7,837	7,482	6,761	6,557	6,354	5,780	5,241	5,238	5,511	5,159	4,367	3,691	3,595	2,058	2,058	1,870	1,383	1,188	1,074	795
PM10 - comb + fug	1,863.4	1,870.2	1,837.6	1,817.2	966.8	952.0	923.6	863.8	1,265.2	1,253.6	1,270.4	1,210.6	890.0	810.1	776.6	353.1	353.0	317.6	267.4	236.4	225.0	172.0
PM2.5 - comb + fug	762.2	766.4	740.9	727.3	474.6	463.4	449.3	410.5	418.2	419.5	438.8	411.3	335.5	292.2	284.4	155.7	155.7	143.0	106.1	91.9	84.7	62.6
SO2	10	10	9	9	8	8	7	7	6	6	6	6	5	4	4	2	2	2	2	1	1	1
ROG	1,693	1,688	1,625	1,586	1,480	1,444	1,415	1,322	1,130	1,143	1,181	1,084	911	783	770	458	458	438	304	257	228	172
CO2e	918,660	909,963	856,806	817,263	739,019	716,209	694,806	634,294	578,153	575,014	601,197	562,328	473,842	401,124	387,689	224,549	224,539	203,152	152,170	130,393	117,693	85,447

ONSITE EMISSIONS (no linears)	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
CO	29	29	29	30	29	29	29	29	28	27	26	25	24	23	22	20	18	17	15	14	12	11
CO2	5092	5172	5215	5237	5183	5109	5030	4904	4723	4550	4407	4263	4043	3791	3559	3265	3010	2756	2487	2237	2009	1766
CH4	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0
N2O	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NOx	47	48	48	48	48	47	46	45	43	42	41	39	37	35	33	30	28	25	23	21	19	16
PM10 - comb + fug	6.1	6.7	7.1	7.6	7.6	7.6	7.6	7.6	7.7	7.8	7.9	8.0	7.6	7.0	6.5	5.8	5.5	5.1	4.8	4.5	4.0	3.4
PM2.5 - comb + fug	3.1	3.3	3.4	3.6	3.6	3.5	3.5	3.5	3.4	3.3	3.3	3.2	3.0	2.8	2.6	2.3	2.1	2.0	1.8	1.6	1.5	1.3
SO2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ROG	9.26	9.41	9.52	9.64	9.63	10	10	9	9	9	9	8	8	8	7	7	6	6	5	4	4	4
CO2e	5140	5221	5264	5286	5232	5157	5077	4950	4766	4591	4447	4302	4079	3825	3590	3294	3037	2780	2509	2257	2027	1782

Construction days per month:

TOTAL EMISSIONS (onsite + linears + offsite)	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
CO	15,823	16,179	16,000	15,978	15,407	15,188	14,582	13,724	13,036	12,214	12,120	10,613	8,799	7,259	5,764	4,185	4,181	4,082	3,503	3,026	2,794	2,152
CO2	2,349,090	2,381,788	2,336,529	2,310,359	2,213,533	2,178,940	2,099,283	1,972,980	1,880,368	1,773,350	1,765,726	1,575,658	1,328,783	1,113,117	924,789	687,847	687,296	666,038	593,410	530,157	498,072	413,595
CH4	413	422	418	418	405	399	382	361	342	318	313	271	222	183	141	108	107	107	91	78	72	55
N2O	176	181	180	181	177	175	167	158	153	140	137	118	97	79	57	45	45	45	41	36	33	26
NOx	11,335	11,316	10,837	10,494	9,755	9,539	9,280	8,641	8,066	7,962	8,202	7,703	6,757	5,942	5,675	4,066	4,066	3,877	3,369	3,134	3,001	2,671
PM10 - comb + fug	2,341.1	2,358.9	2,328.2	2,311.3	1,455.7	1,437.8	1,393.8	1,316.4	1,707.9	1,668.6	1,676.5	1,576.3	1,213.4	1,095.3	1,015.1	571.7	571.5	536.1	479.9	437.8	421.2	354.3
PM2.5 - comb + fug	945.5	953.3	928.5	916.0	661.6	649.3	630.0	585.4	589.8	581.8	598.2	557.2	467.3	411.3	388.0	252.7	252.6	239.9	201.1	183.1	174.2	147.5
SO2	24	24	24	23	22	22	21	20	19	18	18	16	13	11	9	7	7	7	6	5	5	4
ROG	2,085	2,090	2,029	1,993	1,882	1,844	1,800	1,690	1,489	1,476	1,505	1,371	1,158	994	937	607	607	587	447	390	356	287
CO2e	2,412,420	2,446,746	2,401,224	2,375,220	2,276,874	2,241,540	2,159,212	2,029,540	1,934,869	1,823,476	1,814,684	1,617,862	1,363,524	1,141,316	945,557	704,117	703,543	682,157	608,046	542,832	509,823	422,858

TOTAL EMISSIONS (onsite + linears + offsite)	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
CO	81	82	84	86	88	89	89	90	89	88	88	85	82	77	72	66	61	55	50	44	39	34
CO2	12660	12748	12944	13110	13177	13236	13219	13215	13101	12913	12731	12419	11909	11274	10568	9757	8994	8238	7485	6763	6072	5392
CH4	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1
N2O	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0
NOx	72	71	70	69	67	65	64	63	61	59	58	57	54	52	49	46	43	40	37	34	32	29
PM10 - comb + fug	9.5	9.7	10.1	10.5	10.5	10.4	10.4	10.3	10.5	10.6	10.7	10.8	10.2	9.6	8.9	8.1	7.6	7.2	6.7	6.3	5.6	5.0
PM2.5 - comb + fug	4.7	4.7	4.8	4.8	4.7	4.7	4.6	4.5	4.5	4.4	4.4	4.3	4.1	3.8	3.5	3.2	3.0	2.8	2.6	2.4	2.2	1.9
SO2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ROG	12.95	12.70	12.57	12.45	12.21	12	12	12	11	11	11	11	10	10	9	8	8	7	6	6	5	5
CO2e	12956	13057	13265	13443	13520	13588	13577	13576	13464	13272	13088	12767	12242	11590	10862	10026	9240	8460	7684	6941	6228	5528

Hydrogen Energy California, Kern County Power Project
Emission Factors for Onroad Vehicles
1/29/2013

ONSITE - 5 MPH			**Distance Traveled (miles)**				**EF (lbs/mile)**									
Onroad Vehicle	**Fuel Type**	**Vehicle Type**	**Total**	**Dirt**	**Gravel**	**Paved**	**TOC**	**CO**	**NOx**	**PM_{10}**	**SO_2**	**$PM_{2.5}$**	**CO_2**	**N_2O**	**CH_4**	**CO_2e**
Personal Commuting Vehicles	G/D	LDA/ LDT	0.22	0	0.22	0	0.0012	0.0154	0.0012	0.0002	2.43E-05	0.0001	2.57E+00	9.55E-05	1.90E-04	2.604
Light delivery truck (e.g. Fed-Ex)	D	LHDT	0.5	0	0	0.5	0.0011	0.0073	0.0174	0.0003	1.10E-05	0.0003	1.16E+00	6.61E-05	2.20E-05	1.178
Heavy delivery truck (e.g. flat beds carrying construction eqp)	D	HHDT	1	0	0.5	0.5	0.0271	0.0434	0.1010	0.0063	8.16E-05	0.0057	8.48E+00	1.10E-04	1.76E-04	8.515
Import Fill Trucks	D	HHDT	1.5	0.25	0.75	0.5	0.0271	0.0434	0.1010	0.0063	0.0001	0.0057	8.4774	0.0001	0.0002	8.5153

OFFSITE - 50 MPH			**Distance Traveled (miles)**				**EF (lbs/mile)**									
Onroad Vehicle	**Fuel Type**	**Vehicle Type**	**Total**	**Dirt**	**Gravel**	**Paved**	**TOC**	**CO**	**NOx**	**PM_{10}**	**SO_2**	**$PM_{2.5}$**	**CO_2**	**N_2O**	**CH_4**	**CO_2e**
Personal Commuting Vehicles	G/D	LDA/ LDT	39.8	-	-	39.8	0.0002	0.0065	0.0008	0.0001	7.72E-06	0.0000	8.04E-01	9.55E-05	1.90E-04	0.838
Light delivery truck (e.g. Fed-Ex)	D	LHDT	39.5	-	-	39.5	0.0003	0.0013	0.0116	0.0001	1.10E-05	0.0001	1.16E+00	6.61E-05	2.20E-05	1.178
Heavy delivery truck (e.g. flat beds carrying construction eqp)	D	HHDT	39	-	-	39	0.0017	0.0076	0.0377	0.0014	3.53E-05	0.0012	3.68E+00	1.10E-04	1.76E-04	3.721
Import Fill Trucks	D	HHDT	38.5	-	-	38.5	0.0017	0.0076	0.0377	0.0014	0.0000	0.0012	3.6832	0.0001	0.0002	3.7210

Onsite distance for worker vehicles based on parking areas of 100m x 250 m. Assume average one way trip is 175m, round trip of 350 m, or 0.22 miles.
Emission factors from EMFAC2007 (version 2.3) for year 2010
Emission factors for personal commuting vehicles are based on the assumption 50% LDA and 50% LDT
CH_4 and N_2O emission factor for personal commuting vehicles is based on the average factor for gasoline and diesel passenger vehicles from CCAR, GRP Version 3.0, Table C.5
CH_4 and N_2O emission factor for light delivery trucks is based on the factor for diesel light duty trucks from CCAR, GRP Version 3.0, Table C.5
CH_4 and N_2O emission factor for heavy duty tucks is based on the factor for diesel heavy duty trucks from CCAR, GRP Version 3.0, Table C.5

Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**
Number of Worker/ Day	34	59	79	101	149	188	224	301	335	403	500	559	663	777	935	1057
Avg Daily Vehicles/ Day	26	45	60	78	114	145	173	232	258	310	385	430	510	598	720	813
Light delivery trucks	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Heavy delivery trucks	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Import fill trucks	160	160	160	160	160	160	160	0	0	0	0	0	0	0	0	0

Month	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**	**29**	**30**	**31**	**32**
Number of Worker/ Day	1154	1224	1289	1366	1432	1603	1723	1853	1970	1993	2192	2347	2423	2437	2461	2425
Avg Daily Vehicles/ Day	887	942	992	1051	1102	1233	1325	1425	1516	1533	1686	1805	1864	1874	1893	1865
Light delivery trucks	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Heavy delivery trucks	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Import fill trucks	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Month	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**	**41**	**42**	**43**	**44**	**45**	**46**	**47**	**48**	**49**
Number of Worker/ Day	2403	2295	2172	2104	1912	1850	1570	1276	1011	688	549	548	548	507	430	394	297
Avg Daily Vehicles/ Day	1848	1765	1671	1618	1471	1423	1208	982	778	529	422	422	422	390	331	303	228
Light delivery trucks	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Heavy delivery trucks	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Import fill trucks	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Number of workers per commuter vehicle = 1.3
Actual worker schedule data updated 4/3/12 with data from Table 2-28 HECA Manpower R5 04 02 12.xls
Vehicle occupancy rate is based on information from Section 2.0 Project Description.

Assumptions:
Assumed average distance traveled off site for all employees commuting will be 20 miles
times 2 for return trip = 40 miles
22 days per month of construction, average

CO_2 GWP (SAR, 1996) = 1
CH_4 GWP (SAR, 1996) = 21
N_2O GWP (SAR, 1996) = 310

Hydrogen Energy California, Kern County Power Project
Onsite Fugitive Dust Emissions
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ASSUMPTIONS:
1 month of dirt moving
22 construction days per month
10 construction hours per day
19 M, moisture content of surface material (%) (average of soil borings taken onsite at 5 ft)
50 s, silt content of surface material (%) (from soil boring B-4)

Dirt Piling or Material Handling

$E = k * 0.0032 * (U/5)^{1.3} / (M/2)^{1.4}$ USEPA AP42 Chapter 13.2.4 (Aggregate Handling And Storage Piles)

0.35 k for PM_{10}
0.053 k for $PM_{2.5}$
6.25 U = Mean Wind speed (mph) average for Bakersfield Airport 2000-2004
19 M = Moisture content of surface material (%)
0.00006 lb of PM_{10}/ ton of material
0.00001 lb of $PM_{2.5}$/ ton of material

MATERIAL HANDLED (tons/day)	Mitigation Efficiency[1]	MONTH:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
		# pieces of equip:	4	4	6	7	7	9	9	12	12	12	12	10	8	8	7	7
Bob cat loader			0	0	1,207	1,034	1,034	805	805	2,414	2,414	2,414	2,414	2,896	2,715	2,715	3,103	3,103
Excavator - Trencher (CAT320)		tons/day material handled:	0	0	0	0	0	1,609	1,609	1,207	1,207	1,207	1,207	1,448	1,810	1,810	2,069	2,069
Excavator - Backhoe/loader			3,620	3,620	3,620	4,138	4,138	3,218	3,218	2,414	2,414	2,414	2,414	1,448	1,810	1,810	2,069	2,069
Excavator - loader			3,620	3,620	2,414	2,069	2,069	1,609	1,609	1,207	1,207	1,207	1,207	1,448	905	905	0	0
		TOTAL material handled	7,241	7,241	7,241	7,241	7,241	7,241	7,241	7,241	7,241	7,241	7,241	7,241	7,241	7,241	7,241	7,241

MATERIAL HANDLED (tons/day)	Mitigation Efficiency[1]	MONTH:	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
		# pieces of equip:	4	4	3	3	3	3	3	3	0	0	0	1	1	1	1	0
Bob cat loader			5,431	5,431	4,827	4,827	4,827	4,827	4,827	4,827	0	0	0	0	0	0	0	0
Excavator - Trencher (CAT320)		tons/day material handled:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator - Backhoe/loader			1,810	1,810	2,414	2,414	2,414	2,414	2,414	2,414	0	0	0	0	0	0	0	0
Excavator - loader			0	0	0	0	0	0	0	0	0	0	0	7,241	7,241	7,241	7,241	0
		TOTAL material handled	7,241	7,241	7,241	7,241	7,241	7,241	7,241	7,241	0	0	0	7,241	7,241	7,241	7,241	0

MATERIAL HANDLED (tons/day)	Mitigation Efficiency[1]	MONTH:	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
		# pieces of equip:	0	0	0	3	3	4	4	3	2	2	0	0	0	0	0	0	0
Bob cat loader			0	0	0	2,414	2,414	1,810	1,810	2,414	3,620	3,620	0	0	0	0	0	0	0
Excavator - Trencher (CAT320)		tons/day material handled:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator - Backhoe/loader			0	0	0	4,827	4,827	3,620	3,620	2,414	3,620	3,620	0	0	0	0	0	0	0
Excavator - loader			0	0	0	0	0	1,810	1,810	2,414	0	0	0	0	0	0	0	0	0
		TOTAL material handled	0	0	0	7,241	7,241	7,241	7,241	7,241	7,241	7,241	0	0	0	0	0	0	0

Do not include capacity factor because emissions are based on material handled.

6,136 yd^3/day 7,241 ton/day 2,360 density of soil (lb/yd^3)
135,000 yd^3 159,300 tons (USDA NRCS Physical Soil Properties from Kern County for Lockern-Buttonwillow clay)

Excavation 850,000 Cubic yds
Imported Fill 500,000 Cubic yds (assume 10% of entire site in any given month; with equipment present over 35 months, this is a conservative estimate of the max amount of material handled)

Scraping Emissions Factor - Topsoil Removal by Scraper

E = 0.058 lb TSP/ton material handled USEPA AP42 Chapter 11.9 (Western Surface Coal Mining), Table 11.9-4
Material 850,000 cubic yards, total excavation
0.31 fraction of total excavation handled by scrapers 0.31 <-- fraction of all earth moving equipment in months 1-7 that are scrapers
1705 cubic yards per day, for all scrapers, based on 7 months of scrapers
2012 tons/day

TSP 116.7 lb TSP/day
fraction of TSP that is PM10 0.489 from CEIDARS database for construction fugitives
fraction of TSP that is PM2.5 0.102 from CEIDARS database for construction fugitives
PM10 57.1 lb/day
PM2.5 11.9 lb/day
Mitigation for watering 61% (the emission factor does not account for soil moisture)
Mitigated PM10 22.3 lb/day
Mitigated PM2.5 4.6 lb/day

Scrapers in Travel **AP42 Table 11.9-1 (from Table 13.2.3-1)**

$E = 0.051(S)^{2.0}$ for particles ≤ 15 um USEPA AP42 Chapter 13.2.3 (Heavy Construction Operations), Table 13.2.3-1 - refers to
$E = 0.040(S)^{2.5}$ for TSP ≤ 30 um USEPA AP42 Chapter 11.9 (Western Surface Coal Mining), Table 11.9-1

multiply by 0.60 for PM_{10}
multiply TSP equation by 0.031 for $PM_{2.5}$
S = mean vehicle speed (mph)
S = 15.0 mph COC will limit vehicles to 15 mph onsite
34.86 lb ≤ 30 μm/VMT
11.48 lb ≤ 15 μm/VMT
PM_{10} = 6.89 lb PM_{10}/VMT
$PM_{2.5}$ = 1.08 lb $PM_{2.5}$/VMT
Mitigated PM_{10} = 2.69 lb PM_{10}/VMT
Mitigated $PM_{2.5}$ = 0.42 lb $PM_{2.5}$/VMT

Equipment	Daily VMT	Mitigation Efficiency[1]	PM10 Emissions (lb/day)	PM2.5 Emissions (lb/day)
Excavator - Earth Scraper 637	0.9	61%	2.4	0.38

Formula based on lbs per VMT, not hours, so no capacity factor included.

Scrapers Unloading

AP42 Table 11.9-4

0.04 lb TSP / ton material
2012 tons material handled per day
80.5 lb TSP /day

fraction of TSP that is PM10 0.489 from CEIDARS database for construction fugitives
fraction of TSP that is PM2.5 0.102 from CEIDARS database for construction fugitives

PM10 39.4 lb PM10/day
PM2.5 8.2 lb PM2.5/day
Mitigation 61%

Mitigated PM10 15.3 lb PM10/day
Mitigated PM2.5 3.2 lb PM2.5/day

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Grading Emissions Factor — **To be used for all grading activities**

$E = 0.051(S)^{2.0}$ for particles ≤ 15 um — USEPA AP42 Chapter 13.2.3 (Heavy Construction Operations), Table 13.2.3-1 - refers to
$E = 0.040(S)^{2.5}$ for TSP ≤ 30 um — USEPA AP42 Chapter 11.9 (Western Surface Coal Mining), Table 11.9-1

multiply PM15 equation by 0.60 for PM_{10}
multiply TSP equation by 0.031 for $PM_{2.5}$
S = mean vehicle speed (mph)
S = 5.5 mph — the Cat Motor Grader Application Guide states typical operation speed is 4-7 mph; take midpoint of 5.5 mph
2.84 lb ≤ 30 μm/VMT
1.54 lb ≤ 15 μm/VMT
PM_{10} = 0.93 lb PM_{10}/VMT — percent of day operational: 0.5
$PM_{2.5}$ = 0.09 lb $PM_{2.5}$/VMT — VMT: 27.5
Mitigated PM_{10} = 0.36 lb PM_{10}/VMT
Mitigated $PM_{2.5}$ = 0.03 lb $PM_{2.5}$/VMT

Equipment	Daily VMT	Mitigation Efficiency[1]	PM10 Emissions (lb/day)	PM2.5 Emissions (lb/day)
Excavator - Motor Grader (CAT140H)	27.500	61%	9.928	0.943
		Total	**9.93**	**0.94**

Formula based on lbs per VMT, not hours, so no capacity factor included.

Bulldozing/Earth clearing

$E = 1.0(s)^{1.5}/(M)^{1.4}$ for particles ≤ 15 um — USEPA AP42 Chapter 13.2.3 (Heavy Construction Operations), Table 13.2.3-1 - refers to
$E = 5.7(s)^{1.2}/(M)^{1.3}$ for TSP ≤ 30 um — USEPA AP42 Chapter 11.9 (Western Surface Coal Mining), Table 11.9-1, 11.9-3

multiply PM15 equation by 0.75 for PM_{10}
multiply TSP equation by 0.105 for $PM_{2.5}$
50 s = Silt content (%)
19 M = Moisture content of surface material (%)
4.30 lb/hr of PM_{10}
1.42 lb/hr of $PM_{2.5}$
4.30 lb/hr of PM_{10} (mitigated)
1.42 lb/hr of $PM_{2.5}$ (mitigated)

Equipment	Hours per day	Activity Factor	Mitigation Efficiency[1]	PM10 Emissions (lb/hr)	PM10 Emissions (lb/day)	PM2.5 Emissions (lb/hr)	PM2.5 Emissions (lb/day)
Bulldozer D10R	6	100.0%		4.30	25.79	1.42	8.54
Bulldozer D6C	6	100.0%		4.30	25.79	1.42	8.54
			Total	**8.60**	**51.58**	**2.85**	**17.09**

Covered Storage Piles

SCAQMD Table A9-9-E
E = 1.7 * G/1.5 * (365-H)/235 * I/15 * J
PM10 Emission factor from wind erosion of storage piles per day per acre
50 G = Silt content (%)
37 H = Mean number of days per year with at least 0.01 inches of precipitation (from WRCC for Bakersfield Airport Station)
0.3 I = Percentage of time that the unobstructed wind speed exceeds 12 mph at mean pile height (wind speed percentage and average based on 2000-04 (5 yrs) of wind speed data as recorded at Bakersfield Airport station)
0.5 J = Fraction of TSP that is PM_{10} = 0.5
0.791 lb PM_{10}/acre/day
0.08 Mitigated lb PM_{10}/acre/day

Source	Quantity	Size of Pile (acre)	Hours/Day	Mitigation Efficiency[1]	PM10 Emissions (lb/hr)	PM10 Emissions (lb/day)	PM2.5 Emissions (lb/hr)	PM2.5 Emissions (lb/day)
Cover Storage Pile	25	0.25	24	90%	0.02	0.49	0.004	0.103

Pile size and number are assumed
Assume PM2.5 is 20.8% of PM10

Hydrogen Energy California, Kern County Power Project
Onsite Fugitive Dust Emissions
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Travel onsite - paved and unpaved roads

USEPA AP42 Chapter 13.2.2 (Unpaved Roads)

E = k * (s/12)^a * (W/3)^b

Size specific emission factor for vehicle travel on unpaved roads at industrial sites (eqn 1a; lb/VMT)

Constants:	PM2.5	PM10	TSP
k (lb/VMT)	0.15	1.5	4.9
a	0.9	0.9	0.7
b	0.45	0.45	0.45

4 s = Surface material silt content (%) (value for gravel road)
50 s = Surface material silt content (%) (value for dirt surfaces)
value listed in table W = Mean vehicle weight (ton) * weighted mean based on monthly equipment schedule in "onsite equipment" tab

AP 42 13.2.1 Paved Roads, updated January 2011

For a daily basis,
E = [k (sL)^0.91 x (W)^1.02](1-P/4N) equation (2)

	SOURCE
P = number of "wet" days with at least 0.254 mm (0.01 in) of precipitation during the averaging period	Days/year Buttonwillow Station 1940-2011, WRCC
W = average weight (tons) of vehicles traveling the road	"Avg vehicle weight" tab
k = particle size multiplier for particle size range and units of interest	Values from Table 13.2.1-1, PARTICLE SIZE MULTIPLIERS FOR PAVED ROAD EQUATION
sL = road surface silt loading (g/m^2)	Default value from URBEMIS 9.2 for Kern County
N = number of days in the averaging period	

	P	**k**	**sL**	**N**
	#	**lb/VMT**	**g/m2**	**#**
PM2.5	36	0.00054	0.031	365
PM10	36	0.0022	0.031	365

UNMITIGATED EMISSION FACTORS FOR VEHICLES, BY MONTH

Month	**Mitigation Efficiency[1]**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**
Weighted Mean Vehicle Weight (tons)		17.68	16.69	16.05	14.79	13.67	12.91	12.39	5.79	5.10	4.76	4.53	4.50	4.08	3.96	3.83	3.61
PM10 EF (lbs/VMT) - Paved	0%	0.0004	0.0004	0.0004	0.0003	0.0003	0.0003	0.0003	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
PM2.5 EF (lbs/VMT) - Paved		0.0017	0.0016	0.0015	0.0014	0.0013	0.0012	0.0012	0.0005	0.0005	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0003
PM10 EF (lbs/VMT) - Gravel	93%	1.24	1.21	1.19	1.14	1.10	1.08	1.06	0.75	0.71	0.69	0.67	0.67	0.64	0.63	0.62	0.61
PM2.5 EF (lbs/VMT) - Gravel		0.12	0.12	0.12	0.11	0.11	0.11	0.11	0.08	0.07	0.07	0.07	0.07	0.06	0.06	0.06	0.06
PM10 EF (lbs/VMT) - DIRT	83%	12.04	11.73	11.52	11.11	10.72	10.45	10.26	7.29	6.88	6.67	6.53	6.51	6.22	6.14	6.05	5.89
PM2.5 EF (lbs/VMT) - DIRT		1.20	1.17	1.15	1.11	1.07	1.05	1.03	0.73	0.69	0.67	0.65	0.65	0.62	0.61	0.60	0.59

Month	**Mitigation Efficiency[1]**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**	**29**	**30**	**31**	**32**
Weighted Mean Vehicle Weight (tons)		3.59	3.58	3.49	3.53	3.50	3.30	3.24	3.16	3.11	3.04	2.87	2.82	2.74	2.65	2.55	2.52
PM10 EF (lbs/VMT) - Paved	0%	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
PM2.5 EF (lbs/VMT) - Paved		0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0002	0.0002	0.0002
PM10 EF (lbs/VMT) - Gravel	93%	0.60	0.60	0.60	0.60	0.60	0.58	0.58	0.57	0.57	0.56	0.55	0.54	0.54	0.53	0.52	0.52
PM2.5 EF (lbs/VMT) - Gravel		0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05
PM10 EF (lbs/VMT) - DIRT	83%	5.87	5.87	5.80	5.83	5.81	5.66	5.61	5.55	5.50	5.45	5.31	5.27	5.20	5.13	5.04	5.01
PM2.5 EF (lbs/VMT) - DIRT		0.59	0.59	0.58	0.58	0.58	0.57	0.56	0.56	0.55	0.55	0.53	0.53	0.52	0.51	0.50	0.50

Month	**Mitigation Efficiency[1]**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**	**41**	**42**	**43**	**44**	**45**	**46**	**47**	**48**	**49**
Weighted Mean Vehicle Weight (tons)		2.52	2.52	2.50	2.52	2.59	2.63	2.73	2.85	3.03	3.51	3.59	3.59	3.58	3.61	3.84	3.99	4.62
PM10 EF (lbs/VMT) - Paved	0%	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
PM2.5 EF (lbs/VMT) - Paved		0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0004	0.0004	0.0004
PM10 EF (lbs/VMT) - Gravel	93%	0.52	0.52	0.51	0.52	0.52	0.53	0.53	0.55	0.56	0.60	0.60	0.61	0.60	0.61	0.62	0.63	0.68
PM2.5 EF (lbs/VMT) - Gravel		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.07
PM10 EF (lbs/VMT) - DIRT	83%	5.01	5.01	5.00	5.01	5.07	5.11	5.19	5.29	5.44	5.82	5.87	5.88	5.86	5.89	6.05	6.16	6.58
PM2.5 EF (lbs/VMT) - DIRT		0.50	0.50	0.50	0.50	0.51	0.51	0.52	0.53	0.54	0.58	0.59	0.59	0.59	0.59	0.61	0.62	0.66

Mitigation Measure[1]	Control Efficiency	
Apply water every three hours to disturbed surfaces[3]	61%	
Traffic speeds on all unpaved roads to be reduced to 15 mph or less	57%	
Apply chemical dust suppressant annually to unpaved parking areas/disturbed areas	84%	*CEC stated in the background to DR A132 that they will be requiring the use of soil binders on all onsite unpaved roads, including gravel
Combined Mitigation Efficiency - reduced speed + suppressants	**93%**	
Combined Mitigation Efficiency - reduced speed + watering	**83%**	
Water the storage pile by hand or apply cover when wind events are declared.	90%	

Notes:

1. Mitigation efficiencies from SCAQMD Table XI-A and Table XI-E (South Coast Air Quality Management District, Air Quality Analysis Handbook (under development), accessed at http://www.aqmd.gov/ceqa/handbook/mitigation/fugitive/MM_fugitive.html).
2. Equipment weight from SCAQMD Table A9-9-D-3 and various websites.
3. Water trucks operate at least 4 times per day.

Hydrogen Energy California, Kern County Power Project
Calculation of Mean Vehicle Weight by Month
1/29/2013

VEHICLE INVENTORY BY MONTH	Vehicle Weight	MONTHLY VEHICLE COUNT (#)																											
Vehicle Type	**(tons)**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**
Avg Daily Worker Vehicles	1.6	26	45	60	78	114	145	173	232	258	310	385	430	510	598	720	813	887	942	992	1051	1102	1233	1325	1425	1516	1533	1686	1805
Light delivery trucks	9	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Heavy delivery trucks	17.5	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Import fill trucks	25	160	160	160	160	160	160	160	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 cy fill mat'l haul truck	30			10	10	20	20	20	20	10	10	10	10	5	5	5	5	5	5										
Bus	15	2	2	2	2	3	3	3	3	3	3	5	5	5	5	5	5	7	7	7	10	10	10	10	14	14	14	14	14
Concrete Pumper Truck	30						2	2	2	2	2	2	2	2	3	3	3	2	2	2	2	2							1
Dump Truck	15	3	4	4	3	3	3	3	3	3	3	2	2	2	2	2													2
Diesel Tractor (Yard Dog)	11						2	2	2	2	2	2	4	4	4	4	4	8	8	8	8	8	8	8	10	10	10	10	10
Service Truck - 1 ton	15	2	2	2	4	4	4	4	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Pile Driver Truck	15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck - Fuel/Lube	15	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Tractor Truck 5th Wheel	0																												
Trucks - Pickup 3/4 ton	3	5	5	5	5	5	6	7	8	15	15	15	15	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Trucks - 3 ton	11	1	1	1	1	1	2	2	2	4	4	4	4	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Truck - Water	25	5	5	5	5	5	5	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	3	2	2	2
Air Compressor 185 CFM	0.5	2	2	2	2	3	3	3	3	3	3	3	3	3	6	6	6	8	8	8	10	10	10	10	12	12	12	12	12
Air Compressor 750 CFM	0.5					1	1	1	1	2	2	2	2	2	2	2	4	4	4	4	4	4	4	4	4	4	4	4	4
Articulating Boom Platform	0																												
Bob cat loader	0			1	1	1	1	1	4	4	4	4	4	3	3	3	3	3	3	2	2	2	2	2	2				
Bulldozer D10R	0	3	3	3	2	2	2	2	2	2	1	1																	
Bulldozer D6C	0	3	3	3	3	2	2	2	2	2	2	1	1	1	1	1													1
Concrete Trowel Machine	15						2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Concrete Vibrators	0	4	4	4	4	4	4	4	4	4	8	8	8	8	8	8	8	8	4	4	4	2	2	2	2	2	2	2	2
Cranes - Mobile 35 ton	25							1	1	1	4	4	4	4	7	7	7	7	7	7	7	7	7	7	7	7	7	5	5
Cranes - Mobile 45 ton	35											2	2	2	2	2	2	2	2	4	4	4	4	4	4	4	4	4	4
Crane - Mobile 65 ton	45												1	1	2	4	5	5	5	6	6	6	6	6	6	6	6	6	6
Cranes 100 / 150 ton cap	50											1	1	2	2	3	3	4	4	4	4	4	4	4	4	4	4	4	4
Diesel Powered Welder	0				10	10	10	10	10	10	10	10	10	10	10	10	15	15	15	20	20	20	20	20	25	25	25	25	25
Excavator - Backhoe/loader	0	2	2	3	4	4	4	4	4	4	4	4	2	2	2	2	2	1	1	1	1	1	1	1	1				
Excavator - Earth Scraper 637	0	7	7	7	7	4	4	2																					
Excavator - loader	0	2	2	2	2	2	2	2	2	2	2	2	2	1	1														1
Excavator - Motor Grader (CAT140H)	0		1	1	1	3	3																						1
Excavator - Trencher (CAT320)	0						2	2	2	2	2	2	2	2	2	2	2												
Fired Heaters (2,000 BTU)	0					4	4	4	4	3	3	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Forklift	10	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	8	8	8	8	8	8	8	8	8	8	8	6
Fusion Welder	0					2	2	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Heavy Haul / 600 tn Crane	75																		1	1	1	1	1	1	1	1	1		
Heavy Haul / 1,000 tn Crane	75																				1	1	1	1	1	1			
Light Plants	0	1	1	2	4	8	8	8	8	4	4	6	6	8	8	10	10	14	14	14	14	14	14	14	14	14	14	14	14
Man lifts - telescoping	7									5	5	5	10	10	10	10	10	10	10	10	15	15	15	15	20	20	20	20	20
Man lift - scissor	2.5								5	5	5	5	10	10	10	10	10	10	10	10	15	15	15	15	20	20	20	20	20
Portable Compaction Roller	0			5	5	5	5	5	5	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2				
Portable Compaction - Vibratory Plate	0								6	6	6	6	6	6	6	6	6	6	6	6	6	6	6						3
Portable Compaction - Ram	0																												
Pumps	0	3	3	3	6	6	6	6	6	6	6	6	6	6	6	6	6	6	3	3	3	3	3	3	3	3	3	3	3
Portable Power Generators	0	4	4	4	4	6	6	6	6	6	10	10	10	10	10	10	15	15	15	15	15	15	15	20	20	20	20	20	20
Truck Crane - Greater than 200 ton	50												1	1	1	1	1	2	2	3	3	4	4	4	4	4	4	4	4
Truck Crane - Greater than 300 ton	60															1	1	1	1	1	2	2	2	3	3	3	3	3	3
Vibratory Roller Ingersol-Rand 20 ton	20	3	3	3	3	3	3	3	3	3	2	2	2	2	2	1	1	1	1										2
TOTAL VEHICLES		**306**	**327**	**360**	**394**	**453**	**494**	**517**	**428**	**451**	**512**	**594**	**650**	**738**	**834**	**960**	**1063**	**1149**	**1198**	**1250**	**1326**	**1376**	**1505**	**1597**	**1719**	**1806**	**1821**	**1971**	**2099**

Hydrogen Energy California, Kern County Power Proj
Calculation of Mean Vehicle Weight by Month
1/29/2013

VEHICLE INVENTORY BY MONTH	**Vehicle Weight**																					
Vehicle Type	**(tons)**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**	**41**	**42**	**43**	**44**	**45**	**46**	**47**	**48**	**49**
Avg Daily Worker Vehicles	1.6	1864	1874	1893	1865	1848	1765	1671	1618	1471	1423	1208	982	778	529	422	422	422	390	331	303	228
Light delivery trucks	9	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Heavy delivery trucks	17.5	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Import fill trucks	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 cy fill mat'l haul truck	30								3	3	3	3	1	1	1							
Bus	15	14	14	14	14	14	14	14	12	12	12	10	10	5	5	3	3	2	2	2	1	1
Concrete Pumper Truck	30	1	1	1																		
Dump Truck	15	2	2	2	2	2	2	2	2	3	3	3	2	1	1	1	1	1				
Diesel Tractor (Yard Dog)	11	10	10	10	10	10	10	10	4	4	4	4	4	4	4							
Service Truck - 1 ton	15	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1
Pile Driver Truck	15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck - Fuel/Lube	15	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1			
Tractor Truck 5th Wheel	0																					
Trucks - Pickup 3/4 ton	3	25	25	25	25	25	25	25	25	25	25	25	25	25	25	15	15	10	10	10	10	5
Trucks - 3 ton	11	6	6	6	6	6	6	4	3	3	3	3	2	2	2	1	1	1	1			
Truck - Water	25	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1
Air Compressor 185 CFM	0.5	12	12	12	12	12	12	12	8	8	8	6	6	6	6	4	4	4	2	2	1	1
Air Compressor 750 CFM	0.5	4	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Articulating Boom Platform	0																					
Bob cat loader	0								1	1	1	1	1	1	1							
Bulldozer D10R	0																					
Bulldozer D6C	0	1	1	1																		
Concrete Trowel Machine	15									2	2	2	2	2	2							
Concrete Vibrators	0	2	2	2	2	2	2															
Cranes - Mobile 35 ton	25	5	5	5	5	5	5	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1
Cranes - Mobile 45 ton	35	4	2	2	2	2	2	2	2	2	2	2	2	1	1							
Crane - Mobile 65 ton	45	6	6	5	5	4	2	2	2	2	2	1	1	1	1	1	1	1				
Cranes 100 / 150 ton cap	50	2	2	1	1	1	1	1	1													
Diesel Powered Welder	0	25	25	25	25	15	15	15	15	15	10	10	10	10	10	5	5	5	5	3	3	2
Excavator - Backhoe/loader	0								2	2	2	2	1	1	1							
Excavator - Earth Scraper 637	0																					
Excavator - loader	0	1	1	1							1	1	1									
Excavator - Motor Grader (CAT140H)	0	1	1	1					2	2	2	2	1	1	1							
Excavator - Trencher (CAT320)	0																					
Fired Heaters (2,000 BTU)	0	5	5	5	5	3	3	3	2	2	2	2	2	2	2	2	2	2	2	1	1	1
Forklift	10	6	6	6	6	6	6	6	6	6	6	6	6	6	6	2	2	2	2	1	1	1
Fusion Welder	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1							
Heavy Haul / 600 tn Crane	75																					
Heavy Haul / 1,000 tn Crane	75																					
Light Plants	0	14	14	14	10	10	10	10	10	10	10	10	10	5	5	5	5	5	4	4	2	2
Man lifts - telescoping	7	20	20	20	20	20	20	20	15	15	15	10	10	10	10	5	5	5	5	2	2	2
Man lift - scissor	2.5	20	20	20	20	20	20	20	15	15	15	10	10	10	10	10	10	10	10	5	5	5
Portable Compaction Roller	0	2	2	2	2	2	2				2	2	2	1	1							
Portable Compaction - Vibratory Plate	0	3	3	3					4	4	4	4	4	2	2							
Portable Compaction - Ram	0																					
Pumps	0	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2	2	2	2	2	2
Portable Power Generators	0	20	20	20	20	20	20	20	15	15	15	15	10	10	10	10	10	10	5	5	5	2
Truck Crane - Greater than 200 ton	50	4	3	3	2	2	2	1	1	1	1	1										
Truck Crane - Greater than 300 ton	60	3	2																			
Vibratory Roller Ingersol-Rand 20 ton	20	2	2	2							1	1	1	1								
TOTAL VEHICLES		**2154**	**2158**	**2173**	**2131**	**2101**	**2015**	**1911**	**1841**	**1696**	**1647**	**1417**	**1178**	**958**	**708**	**554**	**554**	**548**	**505**	**432**	**400**	**316**

Hydrogen Energy California, Kern County Power Project
Calculation of Mean Vehicle Weight by Month
1/29/2013

CALCULATION OF WEIGHTED MEAN VEHICLE WEIGHT		**MONTHLY VEHICLE GROSS WEIGHT (tons)**																											
Vehicle Type		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**
Avg Daily Worker Vehicles		42	72	97	125	183	231	276	371	412	496	616	688	815	956	1151	1301	1420	1507	1587	1681	1763	1972	2120	2280	2425	2454	2698	2888
Light delivery trucks		90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Heavy delivery trucks		875	875	875	875	875	875	875	875	875	875	875	875	875	875	875	875	875	875	875	875	875	875	875	875	875	875	875	875
Import fill trucks		4000	4000	4000	4000	4000	4000	4000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 cy fill mat'l haul truck		0	0	300	300	600	600	600	600	300	300	300	300	150	150	150	150	150	150	0	0	0	0	0	0	0	0	0	0
Bus		30	30	30	30	45	45	45	45	45	45	75	75	75	75	75	75	105	105	105	150	150	150	150	210	210	210	210	210
Concrete Pumper Truck		0	0	0	0	0	60	60	60	60	60	60	60	60	90	90	90	60	60	60	60	60	0	0	0	0	0	0	30
Dump Truck		45	60	60	45	45	45	45	45	45	45	30	30	30	30	30	0	0	0	0	0	0	0	0	0	0	0	0	30
Diesel Tractor (Yard Dog)		0	0	0	0	0	22	22	22	22	22	22	44	44	44	44	44	88	88	88	88	88	88	88	110	110	110	110	110
Service Truck - 1 ton		30	30	30	60	60	60	60	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Pile Driver Truck		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck - Fuel/Lube		30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Tractor Truck 5th Wheel		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trucks - Pickup 3/4 ton		15	15	15	15	15	18	21	24	45	45	45	45	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Trucks - 3 ton		11	11	11	11	11	22	22	22	44	44	44	44	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
Truck - Water		125	125	125	125	125	125	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	50	75	50	50	50
Air Compressor 185 CFM		1	1	1	1	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	3	3	3	4	4	4	5	5	5	5	6	6	6	6	6
Air Compressor 750 CFM		0	0	0	0	0.5	0.5	0.5	0.5	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2
Articulating Boom Platform		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bob cat loader		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bulldozer D10R		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bulldozer D6C		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Concrete Trowel Machine		0	0	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Concrete Vibrators		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cranes - Mobile 35 ton		0	0	0	0	0	0	25	25	25	100	100	100	100	175	175	175	175	175	175	175	175	175	175	175	175	175	125	125
Cranes - Mobile 45 ton		0	0	0	0	0	0	0	0	0	0	70	70	70	70	70	70	70	70	140	140	140	140	140	140	140	140	140	140
Crane - Mobile 65 ton		0	0	0	0	0	0	0	0	0	0	0	45	45	90	180	225	225	225	270	270	270	270	270	270	270	270	270	270
Cranes 100 / 150 ton cap		0	0	0	0	0	0	0	0	0	0	50	50	100	100	150	150	200	200	200	200	200	200	200	200	200	200	200	200
Diesel Powered Welder		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator - Backhoe/loader		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator - Earth Scraper 637		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator - loader		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator - Motor Grader (CAT140H)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator - Trencher (CAT320)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fired Heaters (2,000 BTU)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Forklift		60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	80	80	80	80	80	80	80	80	80	80	80	60
Fusion Welder		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Heavy Haul / 600 tn Crane		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	75	75	75	75	75	75	75	75	75	0	0
Heavy Haul / 1,000 tn Crane		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	75	75	75	75	75	75	0	0	0
Light Plants		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Man lifts - telescoping		0	0	0	0	0	0	0	0	35	35	35	70	70	70	70	70	70	70	70	105	105	105	105	140	140	140	140	140
Man lift - scissor		0	0	0	0	0	0	0	12.5	12.5	12.5	12.5	25	25	25	25	25	25	25	25	37.5	37.5	37.5	37.5	50	50	50	50	50
Portable Compaction Roller		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Portable Compaction - Vibratory Plate		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Portable Compaction - Ram		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pumps		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Portable Power Generators		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Crane - Greater than 200 ton		0	0	0	0	0	0	0	0	0	0	0	50	50	50	50	50	100	100	150	150	200	200	200	200	200	200	200	200
Truck Crane - Greater than 300 ton		0	0	0	0	0	0	0	0	0	0	0	0	0	0	60	60	60	60	60	120	120	120	180	180	180	180	180	180
Vibratory Roller Ingersol-Rand 20 ton		60	60	60	60	60	60	60	60	60	40	40	40	40	40	20	20	20	20	0	0	0	0	0	0	0	0	0	40
Weighted Mean Vehicle Weight (tons)		**17.7**	**16.7**	**16.0**	**14.8**	**13.7**	**12.9**	**12.4**	**5.8**	**5.1**	**4.8**	**4.5**	**4.5**	**4.1**	**4.0**	**3.8**	**3.6**	**3.6**	**3.6**	**3.5**	**3.5**	**3.5**	**3.3**	**3.2**	**3.2**	**3.1**	**3.0**	**2.9**	**2.8**

Hydrogen Energy California, Kern County Power Proj
Calculation of Mean Vehicle Weight by Month
1/29/2013

CALCULATION OF WEIGHTED MEAN VEHICLE WEIGHT																						
Vehicle Type		**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**	**41**	**42**	**43**	**44**	**45**	**46**	**47**	**48**	**49**
Avg Daily Worker Vehicles		2982	2999	3028	2985	2957	2824	2673	2589	2353	2277	1932	1570	1244	847	676	674	674	624	529	485	366
Light delivery trucks		90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Heavy delivery trucks		875	875	875	875	875	875	875	875	875	875	875	875	875	875	875	875	875	875	875	875	875
Import fill trucks		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 cy fill mat'l haul truck		0	0	0	0	0	0	0	90	90	90	90	30	30	30	0	0	0	0	0	0	0
Bus		210	210	210	210	210	210	210	180	180	180	150	150	75	75	45	45	30	30	30	15	15
Concrete Pumper Truck		30	30	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dump Truck		30	30	30	30	30	30	30	30	45	45	45	30	15	15	15	15	15	0	0	0	0
Diesel Tractor (Yard Dog)		110	110	110	110	110	110	110	44	44	44	44	44	44	44	0	0	0	0	0	0	0
Service Truck - 1 ton		30	30	30	30	30	30	30	30	30	30	30	30	30	30	15	15	15	15	15	15	15
Pile Driver Truck		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck - Fuel/Lube		30	30	30	30	30	30	30	30	30	30	30	15	15	15	15	15	15	15	0	0	0
Tractor Truck 5th Wheel		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trucks - Pickup 3/4 ton		75	75	75	75	75	75	75	75	75	75	75	75	75	75	45	45	30	30	30	30	15
Trucks - 3 ton		66	66	66	66	66	66	44	33	33	33	33	22	22	22	11	11	11	11	0	0	0
Truck - Water		50	50	50	50	50	50	50	50	50	50	50	50	50	50	25	25	25	25	25	25	25
Air Compressor 185 CFM		6	6	6	6	6	6	6	4	4	4	3	3	3	3	2	2	2	1	1	0.5	0.5
Air Compressor 750 CFM		2	1	1	1	1	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Articulating Boom Platform		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bob cat loader		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bulldozer D10R		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bulldozer D6C		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Concrete Trowel Machine		0	0	0	0	0	0	0	0	30	30	30	30	30	30	0	0	0	0	0	0	0
Concrete Vibrators		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cranes - Mobile 35 ton		125	125	125	125	125	125	50	50	50	50	50	50	50	50	50	50	50	25	25	25	25
Cranes - Mobile 45 ton		140	70	70	70	70	70	70	70	70	70	70	70	35	35	0	0	0	0	0	0	0
Crane - Mobile 65 ton		270	270	225	225	180	90	90	90	90	90	45	45	45	45	45	45	45	0	0	0	0
Cranes 100 / 150 ton cap		100	100	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel Powered Welder		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator - Backhoe/loader		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator - Earth Scraper 637		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator - loader		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator - Motor Grader (CAT140H)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator - Trencher (CAT320)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fired Heaters (2,000 BTU)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Forklift		60	60	60	60	60	60	60	60	60	60	60	60	60	60	20	20	20	20	10	10	10
Fusion Welder		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Heavy Haul / 600 tn Crane		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Heavy Haul / 1,000 tn Crane		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Light Plants		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Man lifts - telescoping		140	140	140	140	140	140	140	105	105	105	70	70	70	70	35	35	35	35	14	14	14
Man lift - scissor		50	50	50	50	50	50	50	37.5	37.5	37.5	25	25	25	25	25	25	25	25	12.5	12.5	12.5
Portable Compaction Roller		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Portable Compaction - Vibratory Plate		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Portable Compaction - Ram		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pumps		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Portable Power Generators		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Crane - Greater than 200 ton		200	150	150	100	100	100	50	50	50	50	50	0	0	0	0	0	0	0	0	0	0
Truck Crane - Greater than 300 ton		180	120	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vibratory Roller Ingersol-Rand 20 ton		40	40	40	0	0	0	0	0	0	20	20	20	20	0	0	0	0	0	0	0	0
Weighted Mean Vehicle Weight (tons)		**2.7**	**2.7**	**2.6**	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**	**2.6**	**2.6**	**2.7**	**2.8**	**3.0**	**3.5**	**3.6**	**3.6**	**3.6**	**3.6**	**3.8**	**4.0**	**4.6**

Hydrogen Energy California, Kern County Power Project
Off-Site Linears Fugitive Dust Emissions
1/29/2013

ASSUMPTIONS:
12 months of soil disturbance
10 total construction hours per work day
22 construction days per month

Dirt Piling or Material Handling

E = k * (0.0032) * (U/5)^1.3 / (M/2)^1.4 PM Emissions from Dirt Piling or Material Handling (lb/ton) from USEPA AP42, Chapter 13.2.4 (Aggregate Handling and Storage Piles)

0.053 k for PM2.5
0.35 k for PM10
6.25 U = Mean Wind speed (mph) average for Bakersfield Airport 2000-2004
15 M = Moisture content of surface material (%) (from SCAQMD Table A9-9-G-1 for moist dirt)
0.00001 lb of $PM_{2.5}$/ ton of material
0.00009 lb of PM_{10}/ ton of material

MATERIAL HANDLED (tons/day)	Mitigation Efficiency[1]	MONTH:	1	2	3	4	5	6	7	8	9	10	11	12	13	14
		# pieces of equip:	0	0	0	0	0	0	0	0	0	0	6	7	14	14
Backhoe		tons/day material handled:	0	0	0	0	0	0	0	0	0	0	5454	4675	3896	3896
Excavator			0	0	0	0	0	0	0	0	0	0	0	779	390	390
CAT 325 BACKHOE			0	0	0	0	0	0	0	0	0	0	0	0	390	390
CAT 330 BACKHOE			0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT DOZER D-6			0	0	0	0	0	0	0	0	0	0	0	0	779	779
CAT RUBBER TIRE LOADER 966			0	0	0	0	0	0	0	0	0	0	0	0	0	0
		TOTAL material handled	0	0	0	0	0	0	0	0	0	0	5454	5454	5454	5454

MATERIAL HANDLED (tons/day)	Mitigation Efficiency[1]	MONTH:	15	16	17	18	19	20	21	22	23	24	25	26	27	28
		# pieces of equip:	14	13	14	11	11	11	7	7	0	0	0	0	0	0
Backhoe		tons/day material handled:	3896	4195	3896	4958	4958	4958	4675	4675	0	0	0	0	0	0
Excavator			390	420	390	496	496	496	779	779	0	0	0	0	0	0
CAT 325 BACKHOE			0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT 330 BACKHOE			390	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT DOZER D-6			0	0	390	0	0	0	0	0	0	0	0	0	0	0
CAT RUBBER TIRE LOADER 966			779	839	779	0	0	0	0	0	0	0	0	0	0	0
		TOTAL material handled	5454	5454	5454	5454	5454	5454	5454	5454	0	0	0	0	0	0

MATERIAL HANDLED (tons/day)	Mitigation Efficiency[1]	MONTH:	29	30	31	32	33	34	35	36	37	38	39	40	41	42
		# pieces of equip:	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Backhoe		tons/day material handled:	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator			0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT 325 BACKHOE			0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT 330 BACKHOE			0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT DOZER D-6			0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAT RUBBER TIRE LOADER 966			0	0	0	0	0	0	0	0	0	0	0	0	0	0
		TOTAL material handled	0	0	0	0	0	0	0	0	0	0	0	0	0	0

MATERIAL HANDLED (tons/day)	Mitigation Efficiency[1]	MONTH:	43	44	45	46	47	48	49
		# pieces of equip:	0	0	0	0	0	0	0
Backhoe		tons/day material handled:	0	0	0	0	0	0	0
Excavator			0	0	0	0	0	0	0
CAT 325 BACKHOE			0	0	0	0	0	0	0
CAT 330 BACKHOE			0	0	0	0	0	0	0
CAT DOZER D-6			0	0	0	0	0	0	0
CAT RUBBER TIRE LOADER 966			0	0	0	0	0	0	0
		TOTAL material handled	0	0	0	0	0	0	0

Disturbed Acreage	Length (miles)	ROW width (ft)	Area (ft2)	Area (acres)
Electrical transmission line	2.1	100	1108800	25.45
Natural gas linear	13	50	3432000	78.78
Process water pipeline	14.4	50	3801600	87.27
CO_2 pipeline	3.4	50	897600	20.61
Potable water pipeline	1.2	10	63360	1.45
Railway	5.3	60	1679040	38.54
Sources:			TOTAL:	**252.11**

Lengths: email from William Becktel, 3/26/12
ROW Width: Table 2-01 March 20 from Fluor.doc

Assume tons/day of material is evenly split among the number of pieces of equipment operating in a given month.
Do not include capacity factor because emissions are based on material handled, not hours of operation.

4622 yd^3/day   5454 ton/day
1,220,222 yd^3 1,439,862 tons   2360 density of soil (lb/yd^3)
(USDA NRCS Physical Soil Properties from Kern County
Lockern-Buttonwillow clay soil)
252.11 acres =   1,220,222 cubic yds, assume depth of soils moved is   1 yd

Scraping Emissions Factor

E = 0.058 lb/ton material handled   USEPA AP42 Chapter 11.9 (Western Surface Coal Mining), Table 11.9-4
Material 1,220,222 cubic yards, total excavation
0.17 fraction of total excavation handled by scrapers   0.17 <-- fraction of all earth moving equipment in months 11-22 that are scrapers
4622 cubic yards per day, for all scrapers, based on two months of scrapers in use
5454 tons/day

TSP 316.3 lb TSP/day
fraction of TSP that is PM10 0.489 from CEIDARS database for construction fugitives
fraction of TSP that is PM2.5 0.102 from CEIDARS database for construction fugitives
PM10 154.7 lb/day
PM2.5 32.3 lb/day
Mitigation for watering 61% (the emission factor does not account for soil moisture)
Mitigated PM10 60.3 lb/day
Mitigated PM2.5 12.6 lb/day

Grading Emissions Factor   To be used for all scraping and grading activities

$E = 0.051(S)^{2.0}$ for particles ≤ 15 um   USEPA AP42 Chapter 13.2.3 (Heavy Construction Operations), Table 13.2.3-1 - refers to
$E = 0.040(S)^{2.5}$ for TSP ≤ 30 um   USEPA AP42 Chapter 11.9 (Western Surface Coal Mining), Table 11.9-1

multiply by 0.60 for PM_{10}
multiply TSP equation by 0.031 for $PM_{2.5}$
S = mean vehicle speed (mph)

S = 5.5 mph   the Cat Motor Grader Application Guide states typical operation speed is 4-7 mph; take midpoint of 5.5 mph
2.84 lb ≤ 30 μm/VMT
1.54 lb ≤ 15 μm/VMT
PM_{10} = 0.93 lb PM_{10}/VMT
$PM_{2.5}$ = 0.09 lb $PM_{2.5}$/VMT

Equipment	Daily VMT	Mitigation Efficiency[1]	PM10 Emissions (lb/day)	PM2.5 Emissions (lb/day)
CAT MODEL 12 MOTOR GRADER	27.5	61%	9.928	0.943
		Total	**9.93**	**0.94**

* mileage based on assumed maximum for scrapers in CalEEMod calculations

Formula based on lbs per VMT, not hours, so no capacity factor included.

Off-Site Linears Fugitive Dust Emissions
1/29/2013

Storage Piles
SCAQMD Table A9-9-E
E = 1.7 * G/1.5 * (365-H)/235 * I/15 * J
PM10 Emission factor from wind erosion of storage piles per day per acre

50 G = Silt content (%) (from Geotechnical Investigaion, AFC Appendix P)
37 H = Mean number of days per year with at least 0.01 inches of precipitation (from WRCC for Bakersfield Airport Station)
0.3 I = Percentage of time that the unobstructed wind speed exceeds 12 mph at mean pile height (based on 2000-04 (5 yrs) of wind speed data as recorded at Bakersfield Airport station)
0.5 J = Fraction of TSP that is PM_{10} = 0.5
0.791 lb/acre/day

Source	Quantity	Size of Pile (acre)	Mitigation Efficiency[1]	PM_{10} Emissions (lbs/day)	$PM_{2.5}$ Emissions (lbs/day)
Storage Piles	8	0.25	90%	0.16	0.033

Pile size and number are assumed
Days per year accounts for weekend days also, not just work days
Assume PM2.5 is 20.8% of PM10

Travel on unpaved roads
E = k * (s/12)^a * (W/3)^b — USEPA AP42 Chapter 13.2.2 (Unpaved Roads)
Size specific emission factor for vehicle travel on unpaved roads at industrial sites (eqn 1a; lb/VMT)

Constants:	PM2.5	PM10	TSP
k (lb/VMT)	0.15	1.5	4.9
a	0.9	0.9	0.7
b	0.45	0.45	0.45

4 s = Surface material silt content (%) (value for gravel road)
value listed in tableW = Mean vehicle weight (ton)

Vehicle Type	Round Trips /Day/ Unit	Round Trip Distance on Dirt Surface (mile)	Mean Vehicle Weight (tons)[2]	PM2.5 EF[5] (lbs/VMT)	PM_{10} EF (lbs/VMT)	Mitigation Efficiency[1]	If weight = 0, where is source included
ON ROAD							
Dump Truck	4	0.25	17	0.12	1.22	83%	
Service Truck (MHD-DSL)	1	0.125	4	0.06	0.64	83%	
Pipe Haul Truck and Trailer (HHDT-DSL)			15	0.12	1.15	83%	
Truck (Pickup 3/4 Ton) - MHD-DSL	2	0.25	1	0.03	0.34	83%	
Truck - water	4	0.25	25	0.14	1.45	83%	
OFF ROAD							
Air Compressor	0			0.00	0.00	83%	
Bore Machine (Hydraulic)	0			0.00	0.00	83%	
Crane	1	0.25	12	0.10	1.04	83%	
Backhoe	0		0	0.00	0.00	83%	Dirt piling
Excavator	1	0.25	0	0.00	0.00	83%	Dirt piling
Forklift	4	0.25	10	0.10	0.96	83%	
Welding Generator	0			0.00	0.00	83%	
Roller	4	0.25	20	0.13	1.31	83%	
Pipe Bending Machine	0			0.00	0.00	83%	
RAIL							
AIR COMPRESSOR 185	0	0	1	0.03	0.34	83%	
BOOM TRUCK 12 TON	4	0.25	12	0.10	1.04	83%	
CAT 325 BACKHOE	4	0.25	0	0.00	0.00	83%	Dirt piling
CAT 330 BACKHOE	4	0.25	0	0.00	0.00	83%	Dirt piling
CAT DOZER D-6	4	0.25	0	0.00	0.00	83%	Dirt piling
CAT MODEL 12 MOTOR GRADER	4	0.25	0	0.00	0.00	83%	Grading
CAT ROLLER-COMPACTOR 563	4	0.25	3	0.06	0.56	83%	
CAT RUBBER TIRE LOADER 966	4	0.25	0	0.00	0.00	83%	Dirt piling
CAT SCRAPER 615	4	0.25	0	0.00	0.00	83%	Grading
CRANE-ROUGH TERRAIN 45T	4	0.25	45	0.19	1.89	83%	
GENSET 5KW	0	0	0.5	0.02	0.25	83%	
JOHN DEERE TRACTOR 9400	4	0.25	20	0.13	1.31	83%	
PICK-UP CRAFT	4	0.25	10	0.10	0.96	83%	
PICK-UP OVERHEAD	4	0.25	10	0.10	0.96	83%	
RAIL BALLAST REGULATOR	4	0.25	1	0.03	0.34	83%	
RAIL CLIP MACHINE	4	0.25	0.3	0.02	0.20	83%	
RAIL MOVER-SHUTTLE WAGON	4	0.25	27.5	0.15	1.51	83%	
RAIL TAMPER	4	0.25	27	0.15	1.50	83%	
RAIL WELDER	0	0	0.5	0.02	0.25	83%	
RAMEX WALK BEHIND COMPACTOR	4	0.25	0.1	0.01	0.12	83%	
TRI-AXLE DUMP TRUCK	4	0.25	17	0.12	1.22	83%	
TRUCK FLATBED 14 FOOT	4	0.25	10	0.10	0.96	83%	
TRUCK TRACTOR	4	0.25	10	0.10	0.96	83%	
WATER TRUCK, 4M ON-ROAD	4	0.25	25	0.14	1.45	83%	
WELDING MACHINE 350 AMP	0	0	0.5	0.02	0.25	83%	

Mitigation Measure[1]	Unpaved Roads
Apply water every three hours to disturbed surfaces[3]	61%
Traffic speeds on all unpaved roads to be reduced to 15 mph or less	57%
Combined Mitigation Efficiency	**83%**
Water the storage pile by hand or apply cover when wind events are declared.	90%

Notes:

1. Mitigation efficiencies from SCAQMD Table XI-A and Table XI-E (South Coast Air Quality Management District, Air Quality Analysis Handbook (under development), accessed at http://www.aqmd.gov/ceqa/handbook/mitigation/fugitive/MM_fugitive.html).
2. Equipment weight from SCAQMD Table A9-9-D-3 and various websites.
3. Water trucks operate at least 4 times per day.
4. Assumed maximum travel speed is 5 mph.

5. An emission factor based on mean vehicle weight could not be calculated for the linear equipment since the equipment will be scattered over various linears at different locations. Therefore, emissions remain calculated based on the weight of each piece of equipment; this is a more conservative estimate.

Hydrogen Energy California, Kern County Power Project
Fugitive Dust on Paved Roads
1/29/2013

AP 42 13.2.1 Paved Roads, updated January 2011

For a daily basis,
E = [k (sL)^0.91 x (W)^1.02](1-P/4N) equation (2)

P = number of "wet" days with at least 0.254 mm (0.01 in) of precipitation during the averaging period
W = average weight (tons) of vehicles treaveling the road
k = particle size multiplier for particle size range and units of interest
sL = road surface silt loading (g/m^2)
N = number of days in the averaging period

	k
	lb/VMT
PM2.5	0.00054
PM10	0.0022

Table 13.2.1-1
PARTICLE SIZE MULTIPLIERS FOR PAVED ROAD EQUATION

Heavy Duty Trucks

			Empty	Full	
W=	17.5	tons, average	5	30	tons
sL=	0.031	g/m2 Default value from URBEMIS 9.2 for Kern County			
P=	36	days/year Buttonwillow Station 1940-2011, WRCC			

E=
0.00041 lb/VMT PM2.5 large delivery trucks
0.00169 lb/VMT PM10 large delivery trucks

Light Duty (Delivery) Trucks

W=	9	tons, average
sL=	0.031	g/m2 Default value from URBEMIS 9.2 for Kern County
P=	36	days/year Buttonwillow Station 1940-2011, WRCC

E=
0.00021 lb/VMT PM2.5 large delivery trucks
0.00086 lb/VMT PM10 large delivery trucks

Worker Vehicles

W=	1.6	tons
sL=	0.031	g/m2 Default value from URBEMIS 9.2 for Kern County
P=	36	days/year Buttonwillow Station 1940-2011, WRCC

E=
0.00004 lb/VMT PM2.5 O&M vehicles
0.00015 lb/VMT PM10 O&M vehicles

Hydrogen Energy California, Kern County Power Project
Emission Factors for Onsite Equipment
1/29/2013

Equipment Description	EMFAC designation	Horsepower	Source	Capacity Factor[1]	Emission Factors (lbs/hr)									
					CO	CO_2	CH_4	N_2O	NO_x	PM_{10}	$PM_{2.5}$	SO_x	ROG[2]	CO_2e
On-Road Vehicles														
18 cy fill mat'l haul truck	HHD-DSL		EMFAC	41.0%	0.320	69.786	0.0013	0.001	0.694	0.043	0.039	0.001	0.151	70.16
Bus	HHD-DSL		EMFAC	41.0%	0.320	69.786	0.0013	0.001	0.694	0.043	0.039	0.001	0.151	70.16
Concrete Pumper Truck	HHD-DSL		EMFAC	41.0%	0.320	69.786	0.0013	0.001	0.694	0.043	0.039	0.001	0.151	70.16
Dump Truck	HHD-DSL		EMFAC	41.0%	0.320	69.786	0.0013	0.001	0.694	0.043	0.039	0.001	0.151	70.16
Diesel Tractor (Yard Dog)	HHD-DSL		EMFAC	46.5%	0.320	69.786	0.0013	0.001	0.694	0.043	0.039	0.001	0.151	70.16
Service Truck - 1 ton	HHD-DSL		EMFAC	41.0%	0.320	69.786	0.0013	0.001	0.694	0.043	0.039	0.001	0.151	70.16
Pile Driver Truck	HHD-DSL		EMFAC	41.0%	0.320	69.786	0.0013	0.001	0.694	0.043	0.039	0.001	0.151	70.16
Truck - Fuel/Lube	MHD-DSL		EMFAC	41.0%	0.155	33.180	0.0002	0.001	0.279	0.017	0.015	3.09E-04	0.014	33.39
Tractor Truck 5th Wheel	HHD-DSL		EMFAC	41.0%	0.320	69.786	0.0013	0.001	0.694	0.043	0.039	0.001	0.151	70.16
Trucks - Pickup 3/4 ton	MHD-DSL		EMFAC	41.0%	0.155	33.180	0.0002	0.001	0.279	0.017	0.015	3.09E-04	0.014	33.39
Trucks - 3 ton	HHD-DSL		EMFAC	41.0%	0.320	69.786	0.0013	0.001	0.694	0.043	0.039	0.001	0.151	70.16
Truck - Water	HHD-DSL		EMFAC	41.0%	0.320	69.786	0.0013	0.001	0.694	0.043	0.039	0.001	0.151	70.16
Off Road Vehicles	**Fuel Type**													
Air Compressor 185 CFM	D	50	OFFROAD - Air Compressors	48.0%	0.269	22.251	0.009	0.001	0.227	0.024	0.022	0.000	0.102	22.619
Air Compressor 750 CFM	D	120	OFFROAD - Air Compressors	48.0%	0.331	46.908	0.008	0.001	0.529	0.050	0.046	0.001	0.090	47.498
Articulating Boom Platform	D	50	OFFROAD - Aerial Lifts	50.5%	0.246	38.038	0.006	0.001	0.396	0.032	0.030	0.000	0.061	38.328
Bobcat Loader	D	50	OFFROAD - Rubber Tired Loaders	54.0%	0.363	31.122	0.011	0.001	0.311	0.029	0.027	0.000	0.120	31.523
Bulldozer D10R	D	500	OFFROAD - Crawler Tractors	59.0%	0.951	258.997	0.023	0.006	2.236	0.087	0.080	0.003	0.254	261.224
Bulldozer D6.C	D	120	OFFROAD - Crawler Tractors	59.0%	0.485	65.751	0.012	0.001	0.767	0.067	0.062	0.001	0.129	66.415
Concrete Trowel Machine	D	50	OFFROAD - Surfacing Equipment	49.0%	0.140	14.095	0.004	0.001	0.136	0.012	0.011	0.000	0.048	14.360
Concrete Vibrators	Electric	50	N/A	43.0%										
Cranes - Mobile 35 ton	D	120	OFFROAD - Cranes	43.0%	0.361	50.103	0.008	0.001	0.550	0.049	0.045	0.001	0.092	50.696
Cranes - Mobile 45 ton	D	175	OFFROAD - Cranes	43.0%	0.482	80.272	0.009	0.002	0.775	0.044	0.041	0.001	0.103	81.078
Crane - Mobile 65 ton	D	175	OFFROAD - Cranes	43.0%	0.482	80.272	0.009	0.002	0.775	0.044	0.041	0.001	0.103	81.078
Cranes 100 / 150 ton cap	D	250	OFFROAD - Cranes	43.0%	0.295	112.058	0.009	0.003	0.993	0.035	0.032	0.001	0.104	113.128
Diesel Powered Welder	D	25	OFFROAD - Welders	45.0%	0.060	11.276	0.002	0.000	0.104	0.007	0.006	0.000	0.022	11.404
Backhoe/loader	D	120	OFFROAD - Tractors/Loaders/Backhoes	46.5%	0.352	51.682	0.006	0.001	0.455	0.038	0.035	0.001	0.069	52.232
Earth Scraper	D	500	OFFROAD - Scrapers	66.0%	1.212	321.140	0.029	0.006	2.826	0.110	0.101	0.003	0.319	323.489
Loader	D	120	OFFROAD - Rubber Tired Loaders	54.0%	0.415	58.861	0.009	0.001	0.600	0.052	0.048	0.001	0.097	59.463
Motor Grader	D	120	OFFROAD - Graders	57.5%	0.530	74.898	0.011	0.001	0.771	0.067	0.062	0.001	0.125	75.553
Excavator - Trencher	D	120	OFFROAD - Trenchers	69.5%	0.468	64.837	0.012	0.001	0.785	0.067	0.061	0.001	0.128	65.498
Fired Heaters	D	25	OFFROAD - Other Construction Equipment	62.0%	0.054	13.205	0.001	0.000	0.101	0.004	0.004	0.000	0.016	13.323
Forklift	D	50	OFFROAD - Forklifts	30.0%	0.167	14.659	0.004	0.001	0.145	0.013	0.012	0.000	0.048	14.925
Fusion Welder	Electric	50	N/A	45.0%										
Heavy Haul / Cranes	D	750	OFFROAD - Cranes	43.0%	0.891	302.773	0.024	0.008	2.451	0.088	0.081	0.003	0.262	305.888
Heavy Haul / Cranes	D	750	OFFROAD - Cranes	43.0%	0.891	302.773	0.024	0.008	2.451	0.088	0.081	0.003	0.262	305.888
Light Plants	D	25	OFFROAD - Other Construction Equipment	62.0%	0.054	13.205	0.001	0.000	0.101	0.004	0.004	0.000	0.016	13.323
Man lifts - telescoping	D	50	OFFROAD - Aerial Lifts	50.5%	0.184	19.595	0.006	0.001	0.188	0.017	0.015	0.000	0.065	19.893
Man lift - scissor	Electric		N/A	50.5%										
Portable Compaction Roller	D	120	OFFROAD - Rollers	57.5%	0.406	58.936	0.009	0.001	0.624	0.053	0.049	0.001	0.098	59.541
Portable Compaction - Vibratory Plate	D	15	OFFROAD - Plate Compactors	43.0%	0.026	4.310	0.000	0.000	0.031	0.001	0.001	0.000	0.005	4.372
Portable Compaction - Vibratory Ram	D	50	OFFROAD - Surfacing Equipment	49.0%	0.140	14.095	0.004	0.001	0.136	0.012	0.011	0.000	0.048	14.360
Pumps	D	25	OFFROAD - Other Construction Equipment	62.0%	0.054	13.205	0.001	0.000	0.101	0.004	0.004	0.000	0.016	13.323
Portable Power Generators	D	50	OFFROAD - Generator Sets	74.0%	0.276	30.595	0.009	0.001	0.291	0.025	0.023	0.000	0.097	30.953
Truck Crane - Greater than 300 ton	D	500	OFFROAD - Cranes	43.0%	0.529	179.940	0.014	0.006	1.421	0.052	0.048	0.002	0.155	181.979
Truck Crane - Greater than 200 ton	D	250	OFFROAD - Cranes	43.0%	0.295	112.058	0.009	0.003	0.993	0.035	0.032	0.001	0.104	113.128
Vibratory Roller 20 ton	D	175	OFFROAD - Rollers	43.0%	0.619	108.049	0.011	0.002	1.009	0.055	0.050	0.001	0.124	108.896

Notes:

[1] Capacity factors from SCAQMD Table A9-8-D

[2] Assuming ROGs are equivalent to VOCs

- Emission factors for on-road vehicles are based on results from Emfac Emissions Model 2007 Version 2.3 (HHDT-DSL=heavy heavy-duty trucks-diesel; MHD-DSL=medium heavy duty-diesel). EMFAC scenario year was 2010 and the selected area was Kern County. PM_{10} values include break wear and tire wear.

- Emission factors for off-road vehicles are based on output from Offroad 2007, calendar year 2013 for Kern County.

On-Road Vehicles:

- $PM_{2.5}$ Fraction of PM_{10}, Diesel: 0.920

Off-Road Vehicles:

- PM2.5 Fraction of PM10, Diesel: 0.920

- CH_4 and N_2O factors are derived from California Climate Action Registry General Reporting Protocol Version 3.0 (April 2008), Table C.5 for LDT, MHD, and HHD diesel fueled trucks in the San Joaquin Valley Air Basin (MHD =HHD). These emissions are in g/mile. On-road vehicles are limited to 10 mph, which is used to convert to lb/hr. (See GHG Reference Info tab)

- N_2O factors for off-road vehicles are derived from California Climate Action Registry General Reporting Protocol Version 3.0 (April 2008), Table C.5 (distillate fuel factors for the industrial sector) using the following to convert from kg/gallon to lb/hp-hour, and then multiplying by the rated horsepower rating: 1 gallon/137,000 Btu, 7,000 Btu/hp-hour, and 2.2046 lb/kg. CH_4 factors are from the SCAQMD data.

CO_2 GWP (SAR, 1996) =	1
CH_4 GWP (SAR, 1996) =	21
N_2O GWP (SAR, 1996) =	310

Hydrogen Energy California, Kern County Power Project
Construction Equipment Usage Schedule (on site)
1/29/2013

Month

EQUIPMENT	# of units	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
On Road Vehicles																																																		
18 cy fill mat'l haul truck	185			10	10	20	20	20	20	10	10	10	10	5	5	5	5	5	5																		3	3	3	3	1	1	1							
Bus	365	2	2	2	2	3	3	3	3	3	3	5	5	5	5	5	5	7	7	7	10	10	10	10	14	14	14	14	14	14	14	14	14	14	14	14	12	12	12	10	10	5	5	3	3	2	2	2	1	1
Concrete Pumper Truck	39						2	2	2	2	2	2	2	2	3	3	3	2	2	2	2	2							1	1	1	1																		
Dump Truck	76	3	4	4	3	3	3	3	3	3	3	2	2	2	2	2													2	2	2	2	2	2	2	2	2	3	3	3	2	1	1	1	1	1				
Diesel Tractor (Yard Dog)	236						2	2	2	2	2	2	4	4	4	4	4	8	8	8	8	8	8	8	10	10	10	10	10	10	10	10	10	10	10	10	4	4	4	4	4	4	4							
Service Truck - 1 ton	99	2	2	2	4	4	4	4	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1
Pile Driver Truck	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck - Fuel/Lube	85	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1			
Tractor Truck 5th Wheel	0																																																	
Trucks - Pickup 3/4 ton	931	5	5	5	5	5	6	7	8	15	15	15	15	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	15	15	10	10	10	10	5
Trucks - 3 ton	185	1	1	1	1	1	2	2	2	4	4	4	4	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	4	3	3	3	3	2	2	2	1	1	1	1			
Truck - Water	127	5	5	5	5	5	5	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1
Off Road Vehicles																																																		
Air Compressor 185 CFM	327	2	2	2	2	3	3	3	3	3	3	3	3	3	6	6	6	8	8	8	10	10	10	10	12	12	12	12	12	12	12	12	12	12	12	12	8	8	8	6	6	6	6	4	4	4	2	2	1	1
Air Compressor 750 CFM	98					1	1	1	1	2	2	2	2	2	2	2	4	4	4	4	4	4	4	4	4	4	4	4	4	4	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Articulating Boom Platform	0																																																	
Bob cat loader	62			1	1	1	1	1	4	4	4	4	4	3	3	3	3	3	3	2	2	2	2	2	2												1	1	1	1	1	1	1							
Bulldozer D10R	23	3	3	3	2	2	2	2	2	2	1	1																																						
Bulldozer D6C	33	3	3	3	3	2	2	2	2	2	2	1	1	1	1	1													1	1	1	1																		
Concrete Trowel Machine	58						2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2									2	2	2	2	2	2							
Concrete Vibrators	140	4	4	4	4	4	4	4	4	4	8	8	8	8	8	8	8	8	4	4	4	2	2	2	2	2	2	2	2	2	2	2	2	2	2															
Cranes - Mobile 35 ton	176							1	1	1	4	4	4	4	7	7	7	7	7	7	7	7	7	7	7	7	7	5	5	5	5	5	5	5	5	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1
Cranes - Mobile 45 ton	84											2	2	2	2	2	2	2	2	4	4	4	4	4	4	4	4	4	4	4	2	2	2	2	2	2	2	2	2	2	2	1	1							
Crane - Mobile 65 ton	126												1	1	2	4	5	5	5	6	6	6	6	6	6	6	6	6	6	6	6	5	5	4	2	2	2	2	2	1	1	1	1	1	1	1				
Cranes 100 / 150 ton cap	70											1	1	2	2	3	3	4	4	4	4	4	4	4	4	4	4	4	4	2	2	1	1	1	1	1	1													
Diesel Powered Welder	643				10	10	10	10	10	10	10	10	10	10	10	10	15	15	15	20	20	20	20	20	25	25	25	25	25	25	25	25	25	15	15	15	15	15	10	10	10	10	10	5	5	5	5	3	3	2
Excavator - Backhoe/loader	68	2	2	3	4	4	4	4	4	4	4	4	2	2	2	2	2	1	1	1	1	1	1	1	1												2	2	2	2	1	1	1							
Excavator - Earth Scraper 637	38	7	7	7	7	4	4	2																																										
Excavator - loader	33	2	2	2	2	2	2	2	2	2	2	2	2	1	1														1	1	1	1							1	1	1									
Excavator - Motor Grader (CAT140H)	24		1	1	1	3	3																						1	1	1	1					2	2	2	2	1	1	1							
Excavator - Trencher (CAT320)	22						2	2	2	2	2	2	2	2	2	2	2																																	
Fired Heaters (2,000 BTU)	166					4	4	4	4	3	3	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	3	3	3	2	2	2	2	2	2	2	2	2	2	2	1	1	1
Forklift	285	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	8	8	8	8	8	8	8	8	8	8	8	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	2	2	2	2	1	1	1
Fusion Welder	83					2	2	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	1	1	1	1	1	1	1	1	1	1	1	1	1	1							
Heavy Haul / 600 tn Crane	9																		1	1	1	1	1	1	1	1	1																							
Heavy Haul / 1,000 tn Crane	6																				1	1	1	1	1	1																								
Light Plants	433	1	1	2	4	8	8	8	8	4	4	6	6	8	8	10	10	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	10	10	10	10	10	10	10	10	10	5	5	5	5	5	4	4	2	2
Man lifts - telescoping	506									5	5	5	10	10	10	10	10	10	10	10	15	15	15	15	20	20	20	20	20	20	20	20	20	20	20	20	15	15	15	10	10	10	10	5	5	5	5	2	2	2
Man lift - scissor	540								5	5	5	5	10	10	10	10	10	10	10	10	15	15	15	15	20	20	20	20	20	20	20	20	20	20	20	20	15	15	15	10	10	10	10	10	10	10	10	5	5	5
Portable Compaction Roller	82			5	5	5	5	5	5	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2					2	2	2	2	2	2			2	2	2	1	1								
Portable Compaction - Vibratory Plate	126								6	6	6	6	6	6	6	6	6	6	6	6	6	6	6						3	3	3	3					4	4	4	4	4	2	2							
Portable Compaction - Ram	0																																																	
Pumps	182	3	3	3	6	6	6	6	6	6	6	6	6	6	6	6	6	6	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2	2	2	2	2	2
Portable Power Generators	608	4	4	4	4	6	6	6	6	6	10	10	10	10	10	10	15	15	15	15	15	15	15	20	20	20	20	20	20	20	20	20	20	20	20	20	15	15	15	15	10	10	10	10	10	10	5	5	5	2
Truck Crane - Greater than 200 ton	68												1	1	1	1	1	2	2	3	3	4	4	4	4	4	4	4	4	4	3	3	2	2	2	1	1	1	1	1										
Truck Crane - Greater than 300 ton	34															1	1	1	1	1	2	2	2	3	3	3	3	3	3	3	2																			
Vibratory Roller Ingersol-Rand 20 ton	53	3	3	3	3	3	3	3	3	3	2	2	2	2	2	1	1	1	1										2	2	2	2							1	1	1	1								
Onsite Total	**7534**	**60**	**62**	**80**	**96**	**119**	**129**	**124**	**136**	**133**	**142**	**149**	**160**	**168**	**176**	**180**	**190**	**202**	**196**	**198**	**215**	**214**	**212**	**212**	**234**	**230**	**228**	**225**	**234**	**230**	**224**	**220**	**206**	**193**	**190**	**180**	**163**	**165**	**164**	**149**	**136**	**120**	**119**	**72**	**72**	**66**	**55**	**41**	**37**	**28**
Schedule																																																		
Site Mobilization																																																		
Site Prep/Piling																																																		
Construction																																																		
Commissioning & Start-up																																																		

Notes: Preliminary and Confidential
1 These are approximate values

Hydrogen Energy California, Kern County Power Project
Emission Factors for Offsite Linears Equipment
1/29/2013

					Emission Factors (lbs/hr)									
Equipment Description	EMFAC designation	Horsepower	Source	Capacity Factor[1]	CO	CO_2	CH_4	N_2O	NO_x	PM_{10}	$PM_{2.5}$	SO_x	ROG[2]	CO_2e
On-Road Vehicles					EMFAC									
Dump Truck	HHD-DSL		EMFAC	41.0%	0.320	69.786	0.0018	0.001	0.694	0.043	0.039	0.001	0.151	70.165
Service Truck	HHD-DSL		EMFAC	41.0%	0.320	69.786	0.0018	0.001	0.694	0.043	0.039	0.001	0.151	70.165
Pipe Haul Truck and Trailer (HHDT-DSL)	HHD-DSL		EMFAC	41.0%	0.320	69.786	0.0018	0.001	0.694	0.043	0.039	0.001	0.151	70.165
Trucks - Pickup 3/4 ton	MHD-DSL		EMFAC	41.0%	0.155	33.180	0.0018	0.001	0.279	0.017	0.015	0.000	0.014	33.558
Truck - Water	HHD-DSL		EMFAC	41.0%	0.320	69.786	0.0018	0.001	0.694	0.043	0.039	0.001	0.151	70.165
Off Road Vehicles	**Fuel Type**													
Air Compressor	D	50	OFFROAD - Air Compressors	48.0%	0.269	22.251	0.009	0.001	0.227	0.024	0.022	0.000	0.102	22.619
Bore Machine (Hydraulic)	D	50	OFFROAD - Bore/Drill Rigs	75.0%	0.228	31.009	0.003	0.001	0.257	0.012	0.011	0.000	0.029	31.238
Crane	D	250	OFFROAD - Cranes	43.0%	0.295	112.058	0.009	0.003	0.993	0.035	0.032	0.001	0.104	113.128
Backhoe	D	120	OFFROAD - Tractors/Loaders/Backhoes	46.5%	0.352	51.682	0.006	0.001	0.455	0.038	0.035	0.001	0.069	52.232
Excavator	D	120	OFFROAD - Excavators	58.0%	0.517	73.557	0.010	0.001	0.678	0.058	0.054	0.001	0.108	74.181
Forklift	D	50	OFFROAD - Forklifts	30.0%	0.167	14.659	0.004	0.001	0.145	0.013	0.012	0.000	0.048	14.925
Generator (Welding)	D	50	OFFROAD - Generator Sets	74.0%	0.276	30.595	0.009	0.001	0.291	0.025	0.023	0.000	0.097	30.953
Roller	D	50	OFFROAD - Rollers	57.5%	0.291	25.960	0.009	0.001	0.258	0.024	0.022	0.000	0.102	26.328
Pipe Bending Machine	D	50	OFFROAD - Other Construction Equipment	62.0%	0.265	27.964	0.007	0.001	0.258	0.020	0.019	0.000	0.075	28.281
RAIL														
AIR COMPRESSOR 185	D	49	OFFROAD - Air Compressors	48.0%	0.269	22.251	0.009	0.001	0.227	0.024	0.022	0.000	0.102	22.616
BOOM TRUCK 12 TON	D	300	EMFAC	41.0%	0.320	69.786	0.002	0.001	0.694	0.043	0.039	0.001	0.151	70.165
CAT 325 BACKHOE	D	168	OFFROAD - Tractors/Loaders/Backhoes	46.5%	0.585	101.296	0.009	0.000	0.768	0.043	0.039	0.001	0.098	101.482
CAT 330 BACKHOE	D	222	OFFROAD - Tractors/Loaders/Backhoes	46.5%	0.366	171.583	0.011	0.000	1.163	0.037	0.034	0.002	0.120	171.811
CAT DOZER D-6	D	185	OFFROAD - Crawler Tractors	59.0%	0.744	121.079	0.015	0.000	1.250	0.071	0.065	0.001	0.167	121.395
CAT MODEL 12 MOTOR GRADER	D	140	OFFROAD - Graders	57.5%	0.530	74.898	0.011	0.000	0.771	0.067	0.062	0.001	0.125	75.134
CAT ROLLER-COMPACTOR 563	D	145	OFFROAD - Rollers	57.5%	0.406	58.936	0.009	0.000	0.624	0.053	0.049	0.001	0.098	59.122
CAT RUBBER TIRE LOADER 966	D	253	OFFROAD - Rubber Tired Loaders	54.0%	0.368	148.843	0.011	0.000	1.210	0.042	0.038	0.002	0.126	149.081
CAT SCRAPER 615	D	265	OFFROAD - Scrapers	66.0%	0.641	209.282	0.020	0.000	2.044	0.079	0.073	0.002	0.225	209.709
CRANE-ROUGH TERRAIN 45T	D	173	OFFROAD - Cranes	43.0%	0.482	80.272	0.009	0.000	0.775	0.044	0.041	0.001	0.103	80.467
GENSET 5KW	D	5	OFFROAD - Generator Sets	74.0%	0.069	10.198	0.001	0.000	0.105	0.006	0.006	0.000	0.015	10.228
JOHN DEERE TRACTOR 9400	D	410	OFFROAD - Tractors/Loaders/Backhoes	46.5%	0.744	344.544	0.021	0.000	2.062	0.070	0.064	0.004	0.229	344.977
PICK-UP CRAFT	D	385	OFFROAD - Other Construction Equipment	62.0%	0.523	254.010	0.013	0.000	1.516	0.049	0.045	0.002	0.145	254.285
PICK-UP OVERHEAD	D	260	OFFROAD - Other Construction Equipment	62.0%	0.587	106.420	0.008	0.000	0.799	0.042	0.038	0.001	0.093	106.597
RAIL BALLAST REGULATOR	D	240	OFFROAD - Other Construction Equipment	62.0%	0.587	106.420	0.008	0.000	0.799	0.042	0.038	0.001	0.093	106.597
RAIL CLIP MACHINE	D	80	OFFROAD - Other Construction Equipment	62.0%	0.265	27.964	0.007	0.000	0.258	0.020	0.019	0.000	0.075	28.107
RAIL MOVER-SHUTTLE WAGON	D	250	OFFROAD - Other Construction Equipment	62.0%	0.587	106.420	0.008	0.000	0.799	0.042	0.038	0.001	0.093	106.597
RAIL TAMPER	D	260	OFFROAD - Other Construction Equipment	62.0%	0.587	106.420	0.008	0.000	0.799	0.042	0.038	0.001	0.093	106.597
RAIL WELDER	D	58	OFFROAD - Welders	45.0%	0.060	11.276	0.002	0.000	0.104	0.007	0.006	0.000	0.022	11.317
RAMEX WALK BEHIND COMPACTOR	D	10	OFFROAD - Plate Compactors	43.0%	0.026	4.310	0.000	0.000	0.031	0.001	0.001	0.000	0.005	4.319
TRI-AXLE DUMP TRUCK	D	450	EMFAC	41.0%	0.320	69.786	0.002	0.001	0.694	0.043	0.039	0.001	0.151	70.165
TRUCK FLATBED 14 FOOT	D	362	EMFAC	41.0%	0.320	69.786	0.002	0.001	0.694	0.043	0.039	0.001	0.151	70.165
TRUCK TRACTOR	D	450	OFFROAD - Off-Highway Trucks	41.0%	0.636	272.089	0.020	0.000	1.783	0.063	0.058	0.003	0.217	272.500
WATER TRUCK, 4M ON-ROAD	D	300	EMFAC	41.0%	0.320	69.786	0.002	0.001	0.694	0.043	0.039	0.001	0.151	70.165
WELDING MACHINE 350 AMP	D	25	OFFROAD - Welders	45.0%	0.060	11.276	0.002	0.000	0.104	0.007	0.006	0.000	0.022	11.317

Notes:

[1] Capacity factors from SCAQMD Table A9-8-D

[2] Assuming ROGs are equivalent to VOCs

- Emission factors for on-road vehicles are based on results from Emfac Emissions Model 2010 Version 2.3 (LDT-DSL=light duty class II trucks-diesel; HHDT-DSL=heavy heavy-duty trucks-diesel; MHD-DSL=medium heavy duty-diesel). EMFAC scenario year was 2010.

- Emission factors for off-road vehicles are based on output from Offroad 2007, calendar year 2013 for Kern County.
  On-Road Vehicles:
    - $PM_{2.5}$ Fraction of PM_{10}, Diesel: 0.920
  Off-Road Vehicles:
    - PM2.5 Fraction of PM10, Diesel: 0.920

- CH_4 and N_2O factors are derived from California Climate Action Registry General Reporting Protocol Version 3.0 (April 2008), Table C.5 for LDT, MHD, and HHD diesel fueled trucks in the San Joaquin Valley Air Basin (MHD =HHD). These emissions are in g/mile. On-road vehicles are limited to 10 mph, which is used to convert to lb/hr. (See GHG Reference Info tab)

- N_2O factors for off-road vehicles are derived from California Climate Action Registry General Reporting Protocol Version 3.0 (April 2008), Table C.5 (distillate fuel factors for the industrial sector) using the following to convert from kg/gallon to lb/hp-hour, and then multiplying by the rated horsepower rating: 1 gallon/137,000 Btu, 7,000 Btu/hp-hour, and 2.2046 lb/kg. CH_4 factors are from the SCAQMD data.

CO_2 GWP (SAR, 1996) =	1
CH_4 GWP (SAR, 1996) =	21
N_2O GWP (SAR, 1996) =	310

Hydrogen Energy California, Kern County Power Project
Construction Equipment Usage Schedule (off site linears)
1/29/2013

EQUIPMENT	Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
	# of units																																																	
ON ROAD																																																		
Dump Truck	64											4	4	6	6	6	6	6	6	6	6	4	4																											
Service Truck (MHD-DSL)												2	2	2	2	2	2	3	3	3	3	3	3																											
Pipe Haul Truck and Trailer (HHDT-DSL	30											3	3	3	3	3	3	2	2	2	2	2	2																											
Truck (Pickup 3/4 Ton) - MHD-DSL	150											10	10	10	10	10	10	15	15	15	15	15	15																											
Truck - water	40											2	2	4	4	4	4	4	4	4	4	2	2																											
OFF ROAD																																																		
Air Compressor	48											2	2	4	4	6	6	6	6	4	4	2	2																											
Bore Machine (Hydraulic)	5															1	1	1	1	1																														
Crane	60											2	4	4	6	6	6	6	6	6	6	4	4																											
Backhoe	104											6	6	10	10	10	10	10	10	10	10	6	6																											
Excavator	11												1	1	1	1	1	1	1	1	1	1	1																											
Forklift	42											2	2	4	4	4	4	4	4	4	4	4	2																											
Welding Generator	96											8	8	8	8	8	8	8	8	8	8	8	8																											
Roller	22												2	2	2	2	2	2	2	2	2	2	2																											
Pipe Bending Machine	36											2	2	4	4	4	4	4	4	4	2	2																												
RAIL																																																		
AIR COMPRESSOR 185	8													0	2	2	2	2																																
BOOM TRUCK 12 TON	3													0	0	1	1	1																																
CAT 325 BACKHOE	2													1	1	0	0	0																																
CAT 330 BACKHOE	1													0	0	1	0	0																																
CAT DOZER D-6	5													2	2	0	0	1																																
CAT MODEL 12 MOTOR GRADER	7													2	2	1	1	1																																
CAT ROLLER-COMPACTOR 563	5													2	2	1	0	0																																
CAT RUBBER TIRE LOADER 966	6													0	0	2	2	2																																
CAT SCRAPER 615	3													2	1	0	0	0																																
CRANE-ROUGH TERRAIN 45T	2													0	1	1	0	0																																
GENSET 5KW	6													0	4	2	0	0																																
JOHN DEERE TRACTOR 9400	1													1	0	0	0	0																																
PICK-UP CRAFT	15													3	3	3	3	3																																
PICK-UP OVERHEAD	24													2	6	6	5	5																																
RAIL BALLAST REGULATOR	2													0	0	0	1	1																																
RAIL CLIP MACHINE	2													0	0	0	1	1																																
RAIL MOVER-SHUTTLE WAGON	3													0	0	1	1	1																																
RAIL TAMPER	2													0	0	0	1	1																																
RAIL WELDER	3													0	0	0	2	1																																
RAMEX WALK BEHIND COMPACTOR	1													0	1	0	0	0																																
TRI-AXLE DUMP TRUCK	12													4	6	2	0	0																																
TRUCK FLATBED 14 FOOT	11													1	1	3	3	3																																
TRUCK TRACTOR	2													0	0	1	1	0																																
WATER TRUCK, 4M ON-ROAD	5													1	1	1	1	1																																
WELDING MACHINE 350 AMP	5													1	1	1	1	1																																
TOTAL	**874**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**43**	**48**	**84**	**98**	**96**	**93**	**97**	**72**	**70**	**67**	**55**	**51**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Notes: Preliminary and Confidential
1 These are approximate values
2 Construction Equipment Assumptions - Natural Gas line work begins in month 11 and ends in month 20. Process water line work begins in month 11 and ends in month 17 Potable Water line work begins in month 17 and ends in month 20. CO2 line work begins in month 17 and ends in month 22. Transmission line work begins in month 17 and ends in month 22. Rail spur line work begins in month 13 and ends in month 17

COMBUSTION - Short-term (Month 3)

equipment / vehicles	TOTAL EMISSION RATE (lb/day) $PM_{2.5}$	PM_{10}	CO	NO_2	SO_2
Worker vehicles	0.0	0.0	0.2	0.0	0.0
Delivery trucks	0.3	0.3	2.2	5.1	0.0
Soil import	1.4	1.5	10.4	24.2	0.0
Construction equip	16.2	17.7	166.8	326.4	0.4

equipment / vehicles	number of sources in the model	operating hours per day in the model	MODEL EMISSION RATE per source (lb/hr/source) $PM_{2.5}$ 24hr	PM_{10} 24hr	CO 1 & 8 hr	NO_2 1-hr	SO_2 1,3 & 24 hr
Worker vehicles	36	10	5.41E-06	6.96E-06	5.67E-04	4.54E-05	8.96E-07
Delivery trucks	26	10	1.10E-03	1.22E-03	8.48E-03	1.98E-02	1.59E-05
Soil import	59	10	2.32E-03	2.56E-03	1.76E-02	4.11E-02	3.32E-05
Construction equip	51	10	3.18E-02	3.48E-02	3.27E-01	6.40E-01	7.06E-04

SOURCE PARAMETERS

Source ID	Source Description	Easting (m)	Northing (m)	Base elevation (m)	Stack Height (m)	Temperature K	Exit Velocity (m/s)	Stack diameter (m)	Emissions per source: $PM_{2.5}$ 24hr lb/hr	PM_{10} 24hr lb/hr	CO 1hr & 8hr lb/hr	NO_2 1hr lb/hr	SO_2 1, 3 and 24hr lb/hr
Worker vehicles[1]	Worker vehicles for commuting to/from site			87.9348	0.3	622	0.001	0.051	5.41E-06	6.96E-06	5.67E-04	4.54E-05	8.96E-07
Delivery trucks[2]	Light and heavy duty delivery trucks			87.9348	3	622	57.5	0.127	1.10E-03	1.22E-03	8.48E-03	1.98E-02	1.59E-05
Soil import[2]	Importing soil for fill			87.9348	3	622	57.5	0.127	2.32E-03	2.56E-03	1.76E-02	4.11E-02	3.32E-05
Construction equipment[2]	All construction equipment			87.9348	3	622	59.9	0.102	3.18E-02	3.48E-02	3.27E-01	6.40E-01	7.06E-04

Notes:
1. Stack parameters for worker vehicles modified to reflect realistic stack height and stack diameter for a typical passenger vehicle. Exit velocity was set at 0.001 m/s, per guidance from SJVAPCD for horizontal stacks.
2. Reference for truck stack parameters and worker vehicle temperature: Risk Management Guidance for the Permitting of New Stationary Diesel-Fueled Engines, California EPA-Air Resources Board, October 2000.

	Average horsepower:	HP used for stack params
Worker vehicles	195.5	200
Delivery trucks	275	300
Construction equipment	170	200

COMBUSTION - Long-term (Months 1-12)

equipment / vehicles	TOTAL EMISSION RATE (tons/year) $PM_{2.5}$	PM_{10}	CO	NO_2	SO_2
Worker vehicles	0.00	0.00	0.08	0.01	0.00
Delivery trucks	0.14	0.16	1.09	2.54	0.00
Soil import	0.11	0.12	0.80	1.87	0.00
Construction equip	2.07	2.26	20.60	37.22	0.04

equipment / vehicles	number of sources in the model	Annual Hours of Operation	MODEL EMISSION RATE per source (lb/hr/source) $PM_{2.5}$ annual	PM_{10} annual	CO annual	NO_2 annual	SO_2 annual
Worker vehicles	36	2640	1.68E-05	2.17E-05	1.76E-03	1.41E-04	2.79E-06
Delivery trucks	26	2640	4.17E-03	4.60E-03	3.18E-02	7.41E-02	5.98E-05
Soil import	67	2640	1.19E-03	1.31E-03	9.06E-03	2.11E-02	1.70E-05
Construction equip	142	2640	1.10E-02	1.21E-02	1.10E-01	1.99E-01	2.21E-04

SOURCE PARAMETERS

Source ID	Source Description	Easting (m)	Northing (m)	Base elevation (m)	Stack Height (m)	Temperature K	Exit Velocity (m/s)	Stack diameter (m)	Emissions per source: $PM_{2.5}$ annual lb/hr	PM_{10} annual lb/hr	CO annual lb/hr	NO_2 annual lb/hr	SO_2 annual lb/hr
Worker vehicles[1]	Worker vehicles for commuting to/from site			87.9348	0.3	622	0.001	0.051	1.68E-05	2.17E-05	1.76E-03	1.41E-04	2.79E-06
Delivery trucks[2]	Light and heavy duty delivery trucks			87.9348	3	622	57.5	0.127	4.17E-03	4.60E-03	3.18E-02	7.41E-02	5.98E-05
Soil import[2]	Importing soil for fill			87.9348	3	622	57.5	0.127	1.19E-03	1.31E-03	9.06E-03	2.11E-02	1.70E-05
Construction equipment[2]	All construction equipment			87.9348	3	622	59.9	0.102	1.10E-02	1.21E-02	1.10E-01	1.99E-01	2.21E-04

Notes:
1. Stack parameters for worker vehicles modified to reflect realistic stack height and diameter for a typical passenger vehicle. Exit velocity was set at 0.001 m/s, per guidance from SJVAPCD for horizontal stacks.
2. Reference for truck stack parameters: Risk Management Guidance for the Permitting of New Stationary Diesel-Fueled Engines, California EPA-Air Resources Board, October 2000.

	Average horsepower:	HP used for stack params
Construction equipment	170	200
Worker vehicles	195.5	200
Delivery trucks	275	300

COMBUSTION - Short-term (Month 24)

equipment / vehicles	TOTAL EMISSION RATE (lb/day) $PM_{2.5}$	PM_{10}	CO	NO_2	SO_2
Worker vehicles	0.0	0.1	4.8	0.4	0.0
Delivery trucks	0.3	0.3	2.2	5.1	0.0
Soil import	-	-	-	-	-
Construction equip	22.6	24.8	231.6	384.9	0.5

equipment / vehicles	number of sources in the model	operating hours per day in the model	MODEL EMISSION RATE per source (lb/hr/source) $PM_{2.5}$ 24hr	PM_{10} 24hr	CO 1 & 8 hr	NO_2 1-hr	SO_2 1,3 & 24 hr
Worker vehicles	36	10	1.28E-04	1.64E-04	1.34E-02	1.07E-03	2.11E-05
Delivery trucks	26	10	1.10E-03	1.22E-03	8.48E-03	1.98E-02	1.59E-05
Soil import	-	-	-	-	-	-	-
Construction equip	58	10	3.90E-02	4.27E-02	3.99E-01	6.64E-01	7.81E-04

SOURCE PARAMETERS

Source ID	Source Description	Easting (m)	Northing (m)	Base elevation (m)	Stack Height (m)	Temperature K	Exit Velocity (m/s)	Stack diameter (m)	Emissions per source: $PM_{2.5}$ 24hr lb/hr	PM_{10} 24hr lb/hr	CO 1hr & 8hr lb/hr	NO_2 1hr lb/hr	SO_2 1, 3 and 24hr lb/hr
Worker vehicles[1]	Worker vehicles for commuting to/from site			87.9348	0.3	622	0.001	0.051	1.28E-04	1.64E-04	1.34E-02	1.07E-03	2.11E-05
Delivery trucks[2]	Light and heavy duty delivery trucks			87.9348	3	622	57.5	0.127	1.10E-03	1.22E-03	8.48E-03	1.98E-02	1.59E-05
Soil import[2]	Importing soil for fill			-	-	-	-	-	-	-	-	-	-
Construction equipment[2]	All construction equipment			87.9348	3	622	59.9	0.102	3.90E-02	4.27E-02	3.99E-01	6.64E-01	7.81E-04

Notes:
1. Stack parameters for worker vehicles modified to reflect realistic stack height and diameter for a typical passenger vehicle. Exit velocity was set at 0.001 m/s, per guidance from SJVAPCD for horizontal stacks.
2. Reference for truck stack parameters: Risk Management Guidance for the Permitting of New Stationary Diesel-Fueled Engines, California EPA-Air Resources Board, October 2000.

	Average horsepower:	HP used for stack params
Worker vehicles	195.5	200
Delivery trucks	275	300
Construction equipment	170	200

COMBUSTION - Long-term (Months 20-31)

equipment / vehicles	TOTAL EMISSION RATE (tons/year) $PM_{2.5}$	PM_{10}	CO	NO_2	SO_2
Worker vehicles	0.01	0.01	0.68	0.05	0.00
Delivery trucks	0.04	0.04	0.29	0.68	0.00
Soil import	-	-	-	-	-
Construction equip	2.81	3.07	28.62	47.37	0.06

equipment / vehicles	number of sources in the model	Annual Hours of Operation	MODEL EMISSION RATE per source (lb/hr/source) $PM_{2.5}$ annual	PM_{10} annual	CO annual	NO_2 annual	SO_2 annual
Worker vehicles	36	2640	1.37E-04	1.76E-04	1.43E-02	1.15E-03	2.26E-05
Delivery trucks	26	2640	1.10E-03	1.22E-03	8.48E-03	1.98E-02	1.59E-05
Soil import	-	2640	-	-	-	-	-
Construction equip	142	2640	1.50E-02	1.64E-02	1.53E-01	2.53E-01	2.96E-04

SOURCE PARAMETERS

Source ID	Source Description	Easting (m)	Northing (m)	Base elevation (m)	Stack Height (m)	Temperature K	Exit Velocity (m/s)	Stack diameter (m)	Emissions per source: $PM_{2.5}$ annual lb/hr	PM_{10} annual lb/hr	CO annual lb/hr	NO_2 annual lb/hr	SO_2 annual lb/hr
Worker vehicles[1]	Worker vehicles for commuting to/from site			87.9348	0.3	622	0.001	0.051	1.37E-04	1.76E-04	1.43E-02	1.15E-03	2.26E-05
Delivery trucks[2]	Light and heavy duty delivery trucks			87.9348	3	622	57.5	0.127	1.10E-03	1.22E-03	8.48E-03	1.98E-02	1.59E-05
Soil import[2]	Importing soil for fill			-	-	-	-	-	-	-	-	-	-
Construction equipment[2]	All construction equipment			87.9348	3	622	59.9	0.102	1.50E-02	1.64E-02	1.53E-01	2.53E-01	2.96E-04

Notes:
1. Stack parameters for worker vehicles modified to reflect realistic stack height and diameter for a typical passenger vehicle. Exit velocity was set at 0.001 m/s, per guidance from SJVAPCD for horizontal stacks.
2. Reference for truck stack parameters: Risk Management Guidance for the Permitting of New Stationary Diesel-Fueled Engines, California EPA-Air Resources Board, October 2000.

	Average horsepower:	HP used for stack params
Construction equipment	170	200
Worker vehicles	195.5	200
Delivery trucks	275	300

Hydrogen Energy California, Kern County Power Project
Model Inputs - Fugitive Sources
10/4/2012

FUGITIVES - Short-term (Month 3)

Location	X (m)	Y (m)	AREA (m2)
Parking1	215	100	21500
Parking2	215	100	21500
Parking3	215	100	21500
Parking4	215	100	21500
Parking5	215	100	21500
Parking6	215	100	21500
Delivery / Construction Laydown	1075	290	311750
Construction Area 1 (fmr Soil import)	600	600	360000
Construction Area 2 (fmr Constructio	677	677	458,306

	PM10 lb/day	PM2.5 lb/day
Worker vehicles	1.1	0.1
Delivery trucks	2.1	0.3
Soil import	87.1	8.8
Construction activity	230.8	63.9

Project Site	453 acres	(from Project Description section 2.1.8)
% disturbed in one month	25%	
Acreage disturbed in one month	113.25 acres	

Fugitive Source	Operating Hours per day	TOTAL EMISSION RATE (lb/day)		MODEL EMISSION RATE (g/s-m2)	
		$PM_{2.5}$	PM_{10}	$PM_{2.5}$	PM_{10}
Parking1	10	0.0	0.2	1.06E-08	1.06E-07
Parking2	10	0.0	0.2	1.06E-08	1.06E-07
Parking3	10	0.0	0.2	1.06E-08	1.06E-07
Parking4	10	0.0	0.2	1.06E-08	1.06E-07
Parking5	10	0.0	0.2	1.06E-08	1.06E-07
Parking6	10	0.0	0.2	1.06E-08	1.06E-07
Delivery Trucks	10	0.3	2.1	1.01E-08	8.30E-08
Construction Area 1 (fmr Soil import)	10	36.4	158.9	1.27E-06	5.56E-06
Construction Area 2 (fmr Constructio	10	36.4	158.9	1.00E-06	4.37E-06

Construction Activity — Fugitives from these activities are included above with "Construction equipment"
- Dirt Piling / Material Handling
- Grading
- Bulldozing / Earth clearing
- Covered Storage Piles

FUGITIVES - Long-term (Months 1-12)

Location	X (m)	Y (m)	AREA (m2)
Parking1	215	100	21500
Parking2	215	100	21500
Parking3	215	100	21500
Parking4	215	100	21500
Parking5	215	100	21500
Parking6	215	100	21500
Delivery / Construction Laydown	1075	290	311750
Construction Area 1 (fmr Soil import)	600	600	360000
Construction Area 2 (fmr Constructio	1250	1100	1,374,919

	PM10 lb/day	PM2.5 lb/day
Worker vehicles	27.7	2.8
Delivery trucks	19.9	2.3
Soil import	588.5	59.6
Construction activity	1832.3	509.6

Project Site	453 acres	(from Project Description section 2.1.8)
% disturbed in one year	75%	
Acreage disturbed in one year	339.75 acres	

Fugitive Source	Annual hours of operation	TOTAL EMISSION RATE (tons/yr)		MODEL EMISSION RATE (g/s-m2)	
		$PM_{2.5}$	PM_{10}	$PM_{2.5}$	PM_{10}
Parking1	2640	0.0	0.1	2.25E-08	2.25E-07
Parking2	2640	0.0	0.1	2.25E-08	2.25E-07
Parking3	2640	0.0	0.1	2.25E-08	2.25E-07
Parking4	2640	0.0	0.1	2.25E-08	2.25E-07
Parking5	2640	0.0	0.1	2.25E-08	2.25E-07
Parking6	2640	0.0	0.1	2.25E-08	2.25E-07
Delivery Trucks	2640	0.0	0.2	7.91E-09	6.69E-08
Construction Area 1 (fmr Soil import)	2640	3.1	13.3	8.30E-07	3.53E-06
Construction Area 2 (fmr Constructio	2640	3.1	13.3	2.17E-07	9.24E-07

Construction Activity — Fugitives from these activities are included above with "Construction equipment"
- Dirt Piling / Material Handling
- Grading
- Bulldozing / Earth clearing
- Covered Storage Piles

Hydrogen Energy California, Kern County Power Project
Model Inputs - Fugitive Sources
10/5/2012

FUGITIVES - Short-term (Month 24)

Location	X (m)	Y (m)	AREA (m2)
Parking1	215	100	21500
Parking2	215	100	21500
Parking3	215	100	21500
Parking4	215	100	21500
Parking5	215	100	21500
Parking6	215	100	21500
Delivery / Construction Laydown	1075	290	311750
Construction Area 1 (fmr Soil import)	-	-	-
Construction Area 2 (fmr Construction	677	677	458,306

	PM10 lb/day	PM2.5 lb/day
Worker vehicles	12.3	1.2
Delivery trucks	1.0	0.1
Soil import	0.0	0.0
Construction activity	8.4	0.9

Project Site 453 acres (from Project Description section 2.1.8)
% disturbed in one month 25%
Acreage disturbed in one month 113.25 acres

Fugitive Source	Operating Hours per day	TOTAL EMISSION RATE (lb/day)		MODEL EMISSION RATE (g/s-m2)	
		$PM_{2.5}$	PM_{10}	$PM_{2.5}$	PM_{10}
Parking1	10	0.2	2.1	1.20E-07	1.20E-06
Parking2	10	0.2	2.1	1.20E-07	1.20E-06
Parking3	10	0.2	2.1	1.20E-07	1.20E-06
Parking4	10	0.2	2.1	1.20E-07	1.20E-06
Parking5	10	0.2	2.1	1.20E-07	1.20E-06
Parking6	10	0.2	2.1	1.20E-07	1.20E-06
Delivery Trucks	10	0.1	1.0	4.33E-09	3.98E-08
Construction Area 1 (fmr Soil import)	-	-	-	-	-
Construction Area 2 (fmr Construction	10	0.9	8.4	2.37E-08	2.30E-07

Construction Activity — Fugitives from these activities are included above with "Construction equipment"
- Dirt Piling / Material Handling
- Grading
- Bulldozing / Earth clearing
- Covered Storage Piles

FUGITIVES - Long-term (Months 20-31)

Location	X (m)	Y (m)	AREA (m2)
Parking1	215	100	21500
Parking2	215	100	21500
Parking3	215	100	21500
Parking4	215	100	21500
Parking5	215	100	21500
Parking6	215	100	21500
Delivery / Construction Laydown	1075	290	311750
Construction Area 1 (fmr Soil import)	-	-	-
Construction Area 2 (fmr Construction	1250	1100	1,374,919

	PM10 lb/day	PM2.5 lb/day
Worker vehicles	154.1	15.4
Delivery trucks	11.6	1.3
Soil import	0.0	0.0
Construction activity	241.7	48.0

Project Site 453 acres (from Project Description section 2.1.8)
% disturbed in one year 75%
Acreage disturbed in one year 339.75 acres

Fugitive Source	Annual hours of operation	TOTAL EMISSION RATE (tons/yr)		MODEL EMISSION RATE (g/s-m2)	
		$PM_{2.5}$	PM_{10}	$PM_{2.5}$	PM_{10}
Parking1	2640	0.0	0.3	1.25E-07	1.25E-06
Parking2	2640	0.0	0.3	1.25E-07	1.25E-06
Parking3	2640	0.0	0.3	1.25E-07	1.25E-06
Parking4	2640	0.0	0.3	1.25E-07	1.25E-06
Parking5	2640	0.0	0.3	1.25E-07	1.25E-06
Parking6	2640	0.0	0.3	1.25E-07	1.25E-06
Delivery Trucks	2640	0.0	0.1	4.24E-09	3.91E-08
Soil import	-	-	-	-	-
Construction Equipment	2640	0.5	2.7	3.67E-08	1.85E-07

Construction Activity — Fugitives from these activities are included above with "Construction equipment"
- Dirt Piling / Material Handling
- Grading
- Bulldozing / Earth clearing
- Covered Storage Piles

APPENDIX B

DETAILED OPERATIONAL EMISSION CALCULATIONS FOR ALTERNATIVE 1

Summary of Applicable Operational Emissions for General Conformity (Alternative 1) - 2017 Overlapping with Construction

Hydrogen Energy California LLC *3/05/2013 revision*
HECA Project

Federal NAAQS Nonattainment or Maintenance Area General Name and State	Detailed Status in Nonattainment or Maintenance Area	Authority Agency	Basis to Estimate the Offsite Transportation Distance	Emission Sources / Applicable General Conformity Thresholds / Comparisons	Project Operational Annual Emission Rates - for General Conformity (tpy) CO	NOx	PM10	PM2.5	SO2	VOC
San Joaquin Valley, CA	8-Hour Ozone (2008) Nonattainment - Extreme PM2.5 Nonattainment CO Maintenance - Maderate - Fresno, CA (Part of Fresno County), Modesto, CA (Part of Stanislaus County), Stockton, CA (Part of San Joaquin County) PM10 Maintenance	SJVAPCD	**Construction** - Entire SJVAPCD jurisdiction area (one way trip: trucks = worker vehicles = 20 miles)	Onsite Construction Equipment	2.65	3.84	0.48	0.27	0.00	0.83
				Onsite Trucks	0.15	0.34	0.09	0.03	0.00	0.09
				Onsite Vehicles	0.08	0.01	0.22	0.02	0.00	0.01
				Onsite Total	**2.88**	**4.18**	**0.79**	**0.32**	**0.01**	**0.93**
				Offsite Linears Equipment	0.00	0.00	0.00	0.00	0.00	0.00
				Offsite Trucks	1.02	5.16	0.42	0.21	0.00	0.22
				Offsite Vehicles	5.98	0.72	0.20	0.07	0.01	0.18
				Offsite Total	**6.99**	**5.87**	**0.61**	**0.28**	**0.01**	**0.41**
				Total Construction Emission (ton/yr)	**9.87**	**10.06**	**1.40**	**0.60**	**0.02**	**1.34**
			Operation - Entire SJVAPCD jurisdiction area (one way trip: trains = 63 to 287 miles, trucks = 40 to 80 miles, worker vehicles = 20 miles)	Offsite Train	2.31	8.93	0.14	0.14	0.16	0.25
				Offsite Truck	1.85	3.05	0.84	0.25	0.02	0.26
				Offsite Workers Commuting	1.39	0.16	0.35	0.09	0.00	0.04
				Onsite Train	0.29	0.82	0.01	0.01	0.02	0.04
				Onsite Truck	0.21	0.33	0.05	0.02	0.00	0.05
				Total Operation Emissions	**6.05**	**13.29**	**1.40**	**0.52**	**0.21**	**0.64**
				Total Construction and Operation Overlapping Emissions	**15.92**	**23.35**	**2.80**	**1.12**	**0.23**	**1.98**
				Applicable General Conformity *de minimis* Thresholds	**100**	**10**	**100**	**100**	**100**	**10**
				Less Than Thresholds?	**Yes**	**No**	**Yes**	**Yes**	**Yes**	**Yes**
Los Angeles-South Coast Air Basin, CA	8-Hour Ozone (2008) Nonattainment - Extreme PM10 Nonattainment - Serious PM2.5 Nonattainment NO2 Maintenance CO Maintenance - Serious	SCAQMD	Entire SCAQMD jurisdiction area (one way trip: trucks = 88 to 150 miles)	Offsite Train	0.00	0.00	0.00	0.00	0.00	0.00
				Offsite Truck	1.72	2.84	0.78	0.24	0.02	0.24
				Total Emissions	**1.72**	**2.84**	**0.78**	**0.24**	**0.02**	**0.24**
				Applicable General Conformity *de minimis* Thresholds	**100**	**10**	**70**	**100**	**100**	**10**
				Less Than Thresholds?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Kern County (East Kern), CA	8-Hour Ozone (2008) Nonattainment - Marginal PM10 Nonattainment - Serious	EKAPCD	Entire EKAPCD jurisdiction area (one way trip: trains = 62 to 83 miles)	Offsite Train		4.86	0.08			0.13
				Offsite Truck		0.00	0.00			0.00
				Total Emissions		**4.86**	**0.08**			**0.13**
				Applicable General Conformity *de minimis* Thresholds		**100**	**70**			**100**
				Less Than Thresholds?		**Yes**	**Yes**			**Yes**
Los Angeles-San Bernardino Counties (West Mojave Desert), CA	8-Hour Ozone (2008) Nonattainment - Severe 15 (Part of San Bernardino and Los Angeles Counties)	MDAQMD	Los Angeles-San Bernardino Counties (West Mojave Desert) - 8-hr Ozone (2008) NAA (one way trip: trains = 120	Offsite Train		8.27				0.23
				Offsite Truck		0.00				0.00
				Total Emissions		**8.27**				**0.23**
				Applicable General Conformity *de minimis* Thresholds		**25**				**25**
				Less Than Thresholds?		**Yes**				**Yes**
San Bernardino County, CA (Mojave Desert)	PM10 Nonattainment - Moderate	MDAQMD	Entire MDAQMD jurisdiction area (one way trip: trains = 204 miles)	Offsite Train			0.23			
				Offsite Truck			0.00			
				Total Emissions			**0.23**			
				Applicable General Conformity *de minimis* Thresholds			**100**			
				Less Than Thresholds?			**Yes**			
Sacramento Metro, CA	8-Hour Ozone (2008) Nonattainment - Severe 15 PM10 Nonattainment - Moderate (Sacramento County) PM2.5 Nonattainment CO Maintenance - Moderate - Sacramento, CA (Part of Placer, Sacramento and Yolo Counties)	SMAQMD	Entire SMAQMD jurisdiction area (one way trip: trains = 80 miles)	Offsite Train	0.20	0.77	0.01	0.01	0.01	0.02
				Offsite Truck	0.00	0.00	0.00	0.00	0.00	0.00
				Total Emissions	**0.20**	**0.77**	**0.01**	**0.01**	**0.01**	**0.02**
				Applicable General Conformity *de minimis* Thresholds	**100**	**25**	**100**	**100**	**100**	**25**
				Less Than Thresholds?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Yuba City-Marysville, CA	PM2.5 Nonattainment (Sutter and Part of Yuba Counties)	FRAQMD	Yuba City-Marysville, CA - PM2.5 NAA (one way trip: trains = 50 miles)	Offsite Train		0.48		0.01	0.01	0.01
				Offsite Truck		0.00		0.00	0.00	0.00
				Total Emissions		**0.48**		**0.01**	**0.01**	**0.01**
				Applicable General Conformity *de minimis* Thresholds		**100**		**100**	**100**	**100**
				Less Than Thresholds?		**Yes**		**Yes**	**Yes**	**Yes**
Chico, CA	8-Hour Ozone (2008) Nonattainment - Marginal (Butte County) PM2.5 Nonattainment (Part of Butte County) CO Maintenance - Moderate (Part of Butte County)	BCAQMD	Chico, CA - 8-Hour Ozone (2008) NAA - Entire Butte County (one way trip: trains = 50 miles)	Offsite Train	0.12	0.48		0.01	0.01	0.01
				Offsite Truck	0.00	0.00		0.00	0.00	0.00
				Total Emissions	**0.12**	**0.48**		**0.01**	**0.01**	**0.01**
				Applicable General Conformity *de minimis* Thresholds	**100**	**100**		**100**	**100**	**100**
				Less Than Thresholds?	**Yes**	**Yes**		**Yes**	**Yes**	**Yes**

Summary of Applicable Operational Emissions for General Conformity (Alternative 1) - 2017 Overlapping with Construction

Hydrogen Energy California LLC
HECA Project

3/05/2013 revision

NAAs in State of Arizona	8-Hour Ozone (2008) Nonattainment - Marginal - Phoenix-Mesa, AZ (Part of Maricopa and Pinal County) PM10 Nonattainment (Moderate, Serious, or Maintenance) (12 Counties) PM2.5 Nonattainment - Nogales, AZ (Part of Santa Cruz County), West Central Pinal, AZ (West Pinal County) SO2 Nonattainment - Hayden (Pinal County), AZ (Part of Pinal County), Maintenance - San Manual (Pinal County), AZ, Ajo (Pima County), AZ, Douglas (Cochise County), AZ, Miami (Gila County), AZ CO Maintenance - Serious - Phoenix, AZ. (Part of Maricopa)	ADEQ	Entire ADEQ jurisdiction area (one way trip: trains = 364 miles)	Offsite Train	6.48	25.08	0.41	0.39	0.46	0.69
				Offsite Truck	0.00	0.00	0.00	0.00	0.00	0.00
				Total Emissions	**6.48**	**25.08**	**0.41**	**0.39**	**0.46**	**0.69**
				Applicable General Conformity *de minimis* Thresholds	**100**	**100**	**70**	**100**	**100**	**100**
				Less Than Thresholds?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
NAAs in State of New Mexico	PM10 Nonattainment - Moderate - Anthony, NM (Dona Ana County) CO Maintenance (Bernalillo County) SO2 Maintenance - Grant Co, NM	NMED-AQB	Entire NMED-AQB jurisdiction area (one way trip: trains = 102 miles to coal mine site)	Offsite Train	1.81		1.40		0.13	
				Offsite Truck	0.00		0.00		0.00	
				Total Emissions	**1.81**		**1.40**		**0.13**	
				Applicable General Conformity *de minimis* Thresholds	**100**		**100**		**100**	
				Less Than Thresholds?	**Yes**		**Yes**		**Yes**	

Notes:

1. The associated emissions from the onsite worker travel are negligible
2. To simplify the analysis, the biggest area among all detailed NAA areas was conservativly used to estimate the emissions in each main NAA category area.
   For State of Arizona and New Mexico the total distances accross each state along the train routes were conservativly used to estimate the emissions in NAA.
3. The distance for trains and trucks are varied depending on the type to materials transporting and their destinations.
4. In MDAQMD, it is important to note that the size of the ozone NAA and PM10 NAA area are different and the ozone NAA is smaller than PM10 NAA. Therefore, the train route (distance) within MDAQMD in ozone nonattainment area is smaller than the distance in PM10 nonattainment area.
5. ACRONYMS AND ABBREVIATIONS
   MDAQMD = Mojave Desert Air Quality Management District
   SCAQMD = South Coast Air Quality Management District
   EKAPCD = East Kern County Air Pollution Control District
   SMAQMD = Sacramento Metro Air Quality Management District
   BCAQMD = Butte County Air Quality Management District
   FRAQMD = Feather River Air Quality Management District
   ADEQ = Arizona Department of Environmental Quality
   NMED-AQB = New Mexico Environment Department - Air Quality Bureau
6. Construction of the project is expected to complete in June 2017 and the operation will start from September. Therefore, the operational emissions were scaled from the entire year of project operation.

Summary of Applicable Operational Emissions for General Conformity (Alternative 1) - 2018 and Beyond

Hydrogen Energy California LLC *3/05/2013 revision*
HECA Project

Federal NAAQS Nonattainment or Maintenance Area General Name and State	Detailed Status in Nonattainment or Maintenance Area	Authority Agency	Basis to Estimate the Offsite Transportation Distance	Emission Sources / Applicable General Conformity Thresholds / Comparisons	Project Operational Annual Emission Rates - for General Conformity (tpy)					
					CO	NOx	PM10	PM2.5	SO2	VOC
San Joaquin Valley, CA	8-Hour Ozone (2008) Nonattainment - Extreme PM2.5 Nonattainment CO Maintenance - Moderate - Fresno, CA (Part of Fresno County), Modesto, CA (Part of Stanislaus County), Stockton, CA (Part of San Joaquin County) PM10 Maintenance	SJVAPCD	Entire SJVAPCD jurisdiction area (one way trip: trains = 63 to 287 miles, trucks = 40 to 80 miles, workers= 20 miles)	Offsite Train	6.93	26.80	0.43	0.42	0.49	0.74
				Offsite Truck	5.56	9.15	2.51	0.76	0.07	0.77
				Offsite Workers Commuting	4.17	0.48	1.05	0.28	0.01	0.13
				Onsite Train	0.87	2.45	0.04	0.04	0.06	0.12
				Onsite Truck	0.63	0.98	0.15	0.05	0.01	0.16
				Total Emissions	**18.16**	**39.87**	**4.19**	**1.55**	**0.63**	**1.93**
				Applicable General Conformity *de minimis* Thresholds	**100**	**10**	**100**	**100**	**100**	**10**
				Less Than Thresholds?	**Yes**	**No**	**Yes**	**Yes**	**Yes**	**Yes**
Los Angeles-South Coast Air Basin, CA	8-Hour Ozone (2008) Nonattainment - Extreme PM10 Nonattainment - Serious PM2.5 Nonattainment NO2 Maintenance CO Maintenance - Serious	SCAQMD	Entire SCAQMD jurisdiction area (one way trip: trucks = 88 to 150 miles)	Offsite Train	0.00	0.00	0.00	0.00	0.00	0.00
				Offsite Truck	5.17	8.52	2.34	0.71	0.06	0.72
				Total Emissions	**5.17**	**8.52**	**2.34**	**0.71**	**0.06**	**0.72**
				Applicable General Conformity *de minimis* Thresholds	**100**	**10**	**70**	**100**	**100**	**10**
				Less Than Thresholds?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Kern County (East Kern), CA	8-Hour Ozone (2008) Nonattainment - Marginal PM10 Nonattainment - Serious	EKAPCD	Entire EKAPCD jurisdiction area (one way trip: trains = 62 to 83 miles)	Offsite Train		14.57	0.24			0.40
				Offsite Truck		0.00	0.00			0.00
				Total Emissions		**14.57**	**0.24**			**0.40**
				Applicable General Conformity *de minimis* Thresholds		**100**	**70**			**100**
				Less Than Thresholds?		**Yes**	**Yes**			**Yes**
Los Angeles-San Bernardino Counties (West Mojave Desert), CA	8-Hour Ozone (2008) Nonattainment - Severe 15 (Part of San Bernardino and Los Angeles Counties)	MDAQMD	Los Angeles-San Bernardino Counties (West Mojave Desert) - 8-hr Ozone (2008) NAA (one way trip: trains = 120 miles)	Offsite Train		24.80				0.69
				Offsite Truck		0.00				0.00
				Total Emissions		**24.80**				**0.69**
				Applicable General Conformity *de minimis* Thresholds		**25**				**25**
				Less Than Thresholds?		**Yes**				**Yes**
San Bernardino County, CA (Mojave Desert)	PM10 Nonattainment - Moderate	MDAQMD	Entire MDAQMD jurisdiction area (one way trip: trains = 204 miles)	Offsite Train			0.70			
				Offsite Truck			0.00			
				Total Emissions			**0.70**			
				Applicable General Conformity *de minimis* Thresholds			**100**			
				Less Than Thresholds?			**Yes**			
Sacramento Metro, CA	8-Hour Ozone (2008) Nonattainment - Severe 15 PM10 Nonattainment - Moderate (Sacramento County) PM2.5 Nonattainment CO Maintenance - Moderate - Sacramento, CA (Part of Placer, Sacramento and Yolo Counties)	SMAQMD	Entire SMAQMD jurisdiction area (one way trip: trains = 80 miles)	Offsite Train	0.59	2.30	0.04	0.04	0.04	0.06
				Offsite Truck	0.00	0.00	0.00	0.00	0.00	0.00
				Total Emissions	**0.59**	**2.30**	**0.04**	**0.04**	**0.04**	**0.06**
				Applicable General Conformity *de minimis* Thresholds	**100**	**25**	**100**	**100**	**100**	**25**
				Less Than Thresholds?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Yuba City-Marysville, CA	PM2.5 Nonattainment (Sutter and Part of Yuba Counties)	FRAQMD	Yuba City-Marysville, CA - PM2.5 NAA (one way trip: trains = 50 miles)	Offsite Train		1.44		0.02	0.03	0.04
				Offsite Truck		0.00		0.00	0.00	0.00
				Total Emissions		**1.44**		**0.02**	**0.03**	**0.04**
				Applicable General Conformity *de minimis* Thresholds		**100**		**100**	**100**	**100**
				Less Than Thresholds?		**Yes**		**Yes**	**Yes**	**Yes**
Chico, CA	8-Hour Ozone (2008) Nonattainment - Marginal (Butte County) PM2.5 Nonattainment (Part of Butte County) CO Maintenance - Moderate (Part of Butte County)	BCAQMD	Chico, CA - 8-Hour Ozone (2008) NAA - Entire Butte County (one way trip: trains = 50 miles)	Offsite Train	0.37	1.44		0.02	0.03	0.04
				Offsite Truck	0.00	0.00		0.00	0.00	0.00
				Total Emissions	**0.37**	**1.44**		**0.02**	**0.03**	**0.04**
				Applicable General Conformity *de minimis* Thresholds	**100**	**100**		**100**	**100**	**100**
				Less Than Thresholds?	**Yes**	**Yes**		**Yes**	**Yes**	**Yes**

Summary of Applicable Operational Emissions for General Conformity (Alternative 1) - 2018 and Beyond

Hydrogen Energy California LLC — *3/05/2013 revision*

HECA Project

NAAs in State of Arizona	8-Hour Ozone (2008) Nonattainment - Marginal - Phoenix-Mesa, AZ (Part of Maricopa and Pinal County) PM10 Nonattainment (Moderate, Serious, or Maintenance) (12 Counties) PM2.5 Nonattainment - Nogales, AZ (Part of Santa Cruz County), West Central Pinal, AZ (West Pinal County) SO2 Nonattainment - Hayden (Pinal County), AZ (Part of Pinal County), Maintenance - San Manual (Pinal County), AZ, Ajo (Pima County), AZ, Douglas (Cochise County), AZ, Miami (Gila County), AZ CO Maintenance - Serious - Phoenix, AZ. (Part of Maricopa)	ADEQ	Entire ADEQ jurisdiction area (one way trip: trains = 364 miles)	Offsite Train	19.45	75.23	1.22	1.18	1.37	2.08
				Offsite Truck	0.00	0.00	0.00	0.00	0.00	0.00
				Total Emissions	**19.45**	**75.23**	**1.22**	**1.18**	**1.37**	**2.08**
				Applicable General Conformity *de minimis* Thresholds	**100**	**100**	**70**	**100**	**100**	**100**
				Less Than Thresholds?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
NAAs in State of New Mexico	PM10 Nonattainment - Moderate - Anthony, NM (Dona Ana County) CO Maintenance (Bernalillo County) SO2 Maintenance - Grant Co, NM	NMED-AQB	Entire NMED-AQB jurisdiction area (one way trip: trains = 102 miles to coal mine site)	Offsite Train	5.42		4.21		0.38	
				Offsite Truck	0.00		0.00		0.00	
				Total Emissions	**5.42**		**4.21**		**0.38**	
				Applicable General Conformity *de minimis* Thresholds	**100**		**100**		**100**	
				Less Than Thresholds?	**Yes**		**Yes**		**Yes**	

Notes:

1. The associated emissions from the onsite worker travel are negligible
2. To simplify the analysis, the biggest area among all detailed NAA areas was conservativly used to estimate the emissions in each main NAA category area.
   For State of Arizona and New Mexico the total distances accross each state along the train routes were conservativly used to estimate the emissions in NAA.
3. The distance for trains and trucks are varied depending on the type to materials transporting and their destinations.
4. In MDAQMD, it is important to note that the size of the ozone NAA and PM10 NAA area are different and the ozone NAA is smaller than PM10 NAA. Therefore, the train route (distance) within MDAQMD in ozone nonattainment area is smaller than the distance in PM10 nonattainment area.
5. ACRONYMS AND ABBREVIATIONS
   MDAQMD = Mojave Desert Air Quality Management District
   SCAQMD = South Coast Air Quality Management District
   EKAPCD = East Kern County Air Pollution Control District
   SMAQMD = Sacramento Metro Air Quality Management District
   BCAQMD = Butte County Air Quality Management District
   FRAQMD = Feather River Air Quality Management District
   ADEQ = Arizona Department of Environmental Quality
   NMED-AQB = New Mexico Environment Department - Air Quality Bureau

3/05/2013 revision

Annual Number of Train Cars (incoming/outgoing)

	Coal Cars (incoming)	**Liquid Sulfur Cars (outgoing)**	**Gasification Cars (outgoing)**	**Ammonia Cars (outgoing)**	**Urea Cars (outgoing)**	**UAN Cars (outgoing)**	**Maximum Total Trains per period**
Annual average number of train cars	13100	85	3170	0	4298	2335	22988

		Line-Haul Engine for Product Trains				
	Line-Haul Engine for Coal Train	Liquid Sulfur	Gasification	Ammonia	Urea	UAN
ton-mile/gallon	480	480	480	480	480	480
Train car capacity (ton)	117	100	100	0	100	100
Unloaded train car weight (ton)	25	25	25	25	25	25

480 ton-mile/gallon is based on 2009 *class I rail freight fuel consumption and travel* data (Association of American Railroads, *Railroad Facts*)

	Coal Trains			Liquid Sulfur Product Train			Gasification Solid Product Train		
Area	Miles traveled per Train (mile/engine) - One Way *	Coal Train (ton-miles/year) - Round Trip	Fuel Use for Coal Train (gal/year) - Round Trip	Miles traveled per Train (mile/engine) - One Way	Product Train (ton-miles/year) - Round Trip	Fuel Use for Product Train (gal/year) - Round Trip	Miles traveled per Train (mile/engine) - One Way	Product Train (ton-miles/year) - Round Trip	Fuel Use for Product Train (gal/year) - Round Trip
San Joaquin Valley, CA	63	137,825,100	287,126	150	1,912,500	3,984	63	29,956,500	62,407
Kern County (East Kern), CA	62	135,637,400	282,568		0	0	83	39,457,775	82,201
San Bernardino County, CA (Mojave Desert) (PM10 nonattainment)	204	445,196,950	927,461		0	0	52	24,734,725	51,529
Los Angeles-San Bernardino Counties (West Mojave Desert), CA - (Ozone nonattainment)	120	262,524,000	546,906		0	0		0	0
State of Arizona (PM10 nonattainment, the maximum distance)	364	796,322,800	1,658,947		0	0		0	0
State of New Mexico	102	222,051,550	462,591		0	0		0	0

* Since exact route of coal train was not determined yet, It was assumed that the coal train would travel across the maximum distance of the nonattainment area for all pollutants in Arizona.

	Ammonia Product Train			Urea Product Train			UAN Product Train		
Area	Miles traveled per Train (mile/engine) - One Way	Product Train (ton-miles/year) - Round Trip	Fuel Use for Product Train (gal/year) - Round Trip	Miles traveled per Train (mile/engine) - One Way	Product Train (ton-miles/year) - Round Trip	Fuel Use for Product Train (gal/year) - Round Trip	Miles traveled per Train (mile/engine) - One Way	Product Train (ton-miles/year) - Round Trip	Fuel Use for Product Train (gal/year) - Round Trip
San Joaquin Valley, CA	0	0	0	287	185,007,375	385,418	264	92,466,000	192,631
Sacramento Metro, CA		0	0	80	51,570,000	107,434		0	0
Yuba City-Marysville, CA		0	0	50	32,231,250	67,146		0	0
Chico, CA		0	0	50	32,231,250	67,146		0	0
Other Area in State of California		0	0	161	103,784,625	216,210		0	0

3/05/2013 revision

offsite locomotive travelling speed in average	40	mph
ratio of required horsepower (empty train/full train)	0.76	
locomotive load factor	28%	

Train Type	Coal	Liquid Sulfur	Gasification Solids	Ammonia	Urea	UAN
Railcar Capacity (ton)	117	100	100	-	100	100
Locomotive Engine Power (hp, each)	4,400	3,000	3,000	3,000	3,000	3,000
Railcars per train	111	60	60	60	60	60
Numbers of locomotive engine per train	6	2	2	2	2	2
Total ton of material per locomotive engine	2,165	3,000	3,000	-	3,000	3,000
Total # locomotive engines needed to transport material per year	706	3	106		144	78
Total # locomotive engines needed for returning trains per year	536	2	80	-	109	59
Total locomotive hours per year in San Joaquin Valley, CA	1,956	20	294	-	1,818	906
Total locomotive hours per year in Kern County (East Kern), CA	1,925		387			
Total locomotive hours per year in San Bernardino County, CA (Mojave Desert) (PM10 nonattainment)	6,319		243			
Total locomotive hours per year in Los Angeles-San Bernardino Counties (West Mojave Desert), CA - (Ozone nonattainment)	3,726					
Total locomotive hours per year in Arizona (PM10 nonattainment, the maximum distance)	11,303					
Total locomotive hours per year in Arizona (PM2.5 nonattainment)	621					
Total locomotive hours per year in Arizona (Ozone nonattainment)	3,105					
Total locomotive hours per year in State of Arizona	6,210					
Total locomotive hours per year in State of New Mexico	3,152					
Total locomotive hours per year in Sacramento Metro, CA					507	
Total locomotive hours per year in Yuba City-Marysville, CA					317	
Total locomotive hours per year in Chico, CA					317	
Total locomotive hours per year in Other Area in the rest State of California and State of Oregon/State of Washington					1,020	

3/05/2013 revision

	Line-Haul Emission Factors	CO	NOx	PM10	PM2.5	SO2	VOC
	Tier 3 Emission Factor (g/bhp-hr)	1.28	4.95	0.08	0.08	0.09	0.14
	Tier 3 Emission Factor (g/gal)	26.62	102.96	1.66	1.61	1.88	2.85

Annual Emission Rates by Area

Area	Train Types	CO	NOx	PM10	PM2.5	SO2	VOC
		Annual Emission Rates (tons/year) all trains					
San Joaquin Valley, CA	Line-haul coal engines	3.37	13.02	0.21	0.20	0.24	0.36
	Line-haul liquid sulfur product engines	0.02	0.09	0.00	0.00	0.00	0.00
	Line-haul gasification product engines	0.34	1.33	0.02	0.02	0.02	0.04
	Line-haul ammonia product engines	0.00	0.00	0.00	0.00	0.00	0.00
	Line-haul urea product engines	2.13	8.25	0.13	0.13	0.15	0.23
	Line-haul UAN product engines	1.06	4.11	0.07	0.06	0.08	0.11
	Total Trains (ton/yr)	**6.93**	**26.80**	**0.43**	**0.42**	**0.49**	**0.74**
Kern County (East Kern), CA	Line-haul coal engines	3.31	12.81	0.21	0.20	0.23	0.35
	Line-haul gasification product engines	0.45	1.76	0.03	0.03	0.03	0.05
	Total Trains (ton/yr)	**3.77**	**14.57**	**0.24**	**0.23**	**0.27**	**0.40**
San Bernardino County, CA (Mojave Desert) (PM10 nonattainment)	Line-haul coal engines	10.88	42.06	0.68	0.66	0.77	1.16
	Line-haul gasification product engines	0.28	1.10	0.02	0.02	0.02	0.03
	Total Trains (ton/yr)	**11.16**	**43.16**	**0.70**	**0.68**	**0.79**	**1.19**
Los Angeles-San Bernardino Counties (West	Line-haul coal engines	6.41	24.80	0.40	0.39	0.45	0.69
	Line-haul gasification product engines	0.00	0.00	0.00	0.00	0.00	0.00
	Total Trains (ton/yr)	**6.41**	**24.80**	**0.40**	**0.39**	**0.45**	**0.69**
State of Arizona	Line-haul coal engines	19.45	75.23	1.22	1.18	1.37	2.08
	Total Trains (ton/yr)	**19.45**	**75.23**	**1.22**	**1.18**	**1.37**	**2.08**
Sacramento Metro, CA	Line-haul urea product engines	0.59	2.30	0.04	0.04	0.04	0.06
	Total Trains (ton/yr)	**0.59**	**2.30**	**0.04**	**0.04**	**0.04**	**0.06**
Yuba City-Marysville, CA	Line-haul urea product engines	0.37	1.44	0.02	0.02	0.03	0.04
	Total Trains (ton/yr)	**0.37**	**1.44**	**0.02**	**0.02**	**0.03**	**0.04**
Chico, CA	Line-haul urea product engines	0.37	1.44	0.02	0.02	0.03	0.04
	Total Trains (ton/yr)	**0.37**	**1.44**	**0.02**	**0.02**	**0.03**	**0.04**
Other Area in California and State of Oregon/State of Washington	Line-haul urea product engines	1.20	4.63	0.07	0.07	0.08	0.13
	Total Trains (ton/yr)	**1.20**	**4.63**	**0.07**	**0.07**	**0.08**	**0.13**
State of New Mexico	Line-haul coal engines	5.42	20.98	0.34	0.33	0.38	0.58
	Total Trains (ton/yr)	**5.42**	**20.98**	**0.34**	**0.33**	**0.38**	**0.58**

EPA Estimated Locomotive (line-haul) Average Emission Rates by Tiers

Tier	Emission Factor (g/bhp-hr)			
	CO	NO_X	PM	HC
Uncontrolled	1.28	13.00	0.32	0.48
Tier 0	1.28	8.60	0.32	0.48
Tier 0+	1.28	7.20	0.20	0.30
Tier 1	1.28	6.70	0.32	0.47
Tier 1+	1.28	6.70	0.20	0.29
Tier 2	1.28	4.95	0.18	0.26
Tier 2+ and Tier 3	1.28	4.95	0.08	0.13
Tier 4	1.28	1.00	0.015	0.04

3/05/2013 revision

Emission Factors For all Locomotives
SOx [3]
g/gal
1.88

Locomotive Application	Conversion Factor (bhp-hr/gal)
Large Line-haul & Passenger	20.8
Small Line-haul	18.2
Switching	15.2

Note:

(1) EPA's Technical Highlights: Emission Factors for Locomotives, 2009 (http://www.epa.gov/nonroad/locomotv/420f09025.pdf).

(2) Line-haul engine emissions of CO, NOx, PM, and HC are based on EPA Tier 2+ and Tier 3 emission factors.

(3) Based on 300 ppm sulfur diesel fuel.

(4) VOC emissions can be assumed to be equal to 1.053 times the HC emissions

(5) $PM_{2.5}$ Fraction of PM_{10}, = 0.97

(6) No off-site switching or idling was assumed for train transportation.

(7) Average line haul locomotive load factor was obtained from Table 5.12 of The Port Of Long Beach - 2007 Air Emissions Inventory (http://www.polb.com/civica/filebank/blobdload.asp?BlobID=6021)

Summary of Truck Emissions - HECA

3/05/2013 revision

Calculations for Trucks Operations

Data Supplied By Client							
Parameter	**Coke Trucks (Max @ 50 or 60 mph)**	**Liquid Sulfur Product Trucks (Max @ 50 or 60 mph)**	**Gasification Product Trucks (Max @ 50 or 60 mph)**	**Ammonia Product Trucks (Max @ 50 or 60 mph)**	**Urea Product Trucks (Max @ 50 or 60 mph)**	**UAN Sulfur Product Trucks (Max @ 50 or 60 mph)**	**Equipment and Miscellaneous Trucks (Max @ 50 or 60 mph)**
	Running Emissions	**Running Emissions**	**Running Emissions**	**Running Emissions**	**Running Emissions**	**Running Emissions**	**Running Emissions**
Distance traveled per truck in San Joaquin Valley, CA (mi)	104	104	160	0	80	80	92
Distance traveled per truck in Los Angeles-South Coast Air Basin, CA (mi)	176	180	0	0	0	0	151
Maximum number of trucks or loads:							
Annual average trucks or loads	15,200	1,020	3,170	0	5,730	9,340	4,690

No off-site idling was assumed for truck transportation.
Distance traveled per truck is based on round-trip.

EMFAC2007 Emission Factors + Fugitive Dust (g/mi) For Truck Model year 2010, Scenario year 2015

Pollutant	Coke and Coal Trucks (Max @ 50 or 60 mph) Running Emissions (g/mile/trk)	Liquid Sulfur Product Trucks (Max @ 50 or 60 mph) Running Emissions (g/mile/trk)	Gasification Product Trucks (Max @ 50 or 60 mph) Running Emissions (g/mile/trk)	Ammonia Product Trucks (Max @ 50 or 60 mph) Running Emissions (g/mile/trk)	Urea Product Trucks (Max @ 50 or 60 mph) Running Emissions (g/mile/trk)	UAN Sulfur Product Trucks (Max @ 50 or 60 mph) Running Emissions (g/mile/trk)	Equipment and Miscelleneous Trucks (Max @ 50 or 60 mph) Running Emissions (g/mile/trk)
CO	1.32	1.32	1.32	1.32	1.32	1.32	1.32
NOx	2.17	2.17	2.17	2.17	2.17	2.17	2.17
ROG	0.18	0.18	0.18	0.18	0.18	0.18	0.18
SOx	0.02	0.02	0.02	0.02	0.02	0.02	0.02
PM10 *	0.60	0.60	0.60	0.60	0.60	0.60	0.60
PM2.5 *	0.18	0.18	0.18	0.18	0.18	0.18	0.18

EMFAC2007 is the approved federal model for vehicle combustion emissions
* PM10 and PM2.5 includes fugitive dust factor for paved roads obtained from AP-42 Ch. 13 plus PM factors from EMFAC 2007
PM factors from EMFAC = combustion exhaust + tire wear + break wear
The maximum emission factor from either truck speed at 50 mph or 60 mph was used.
Most California highways have speed limits of 60 or 70 mph and large trucks travel more slowly than the speed limit.

Annual Emission Rates in ton/yr all trucks

Pollutant	Coke and Coal Trucks (Max @ 50 or 60 mph) Running Emissions	Liquid Sulfur Product Trucks (Max @ 50 or 60 Running Emissions	Gasification Product Trucks (Max @ 50 or 60 Running Emissions	Ammonia Product Trucks (Max @ 50 or 60 mph) Running Emissions	Urea Product Trucks (Max @ 50 or 60 mph) Running Emissions	UAN Sulfur Product Trucks (Max @ 50 or 60 mph) Running Emissions	Equipment and Miscelleneous Trucks (Max Running Emissions	Total Truck Emission Rates (tons/yr)
San Joaquin Valley, CA								
CO	2.29	0.15	0.74	0.00	0.66	1.08	0.63	**5.56**
NOx	3.78	0.25	1.21	0.00	1.09	1.78	1.03	**9.15**
ROG	0.32	0.02	0.10	0.00	0.09	0.15	0.09	**0.77**
SOx	0.03	0.00	0.01	0.00	0.01	0.01	0.01	**0.07**
PM10	1.04	0.07	0.33	0.00	0.30	0.49	0.28	**2.51**
PM2.5	0.31	0.02	0.10	0.00	0.09	0.15	0.09	**0.76**
Los Angeles-South Coast Air Basin, CA								
CO	3.88	0.27	0.00	0.00	0.00	0.00	1.03	**5.17**
NOx	6.39	0.44	0.00	0.00	0.00	0.00	1.69	**8.52**
ROG	0.54	0.04	0.00	0.00	0.00	0.00	0.14	**0.72**
SOx	0.05	0.00	0.00	0.00	0.00	0.00	0.01	**0.06**
PM10	1.76	0.12	0.00	0.00	0.00	0.00	0.46	**2.34**
PM2.5	0.53	0.04	0.00	0.00	0.00	0.00	0.14	**0.71**

Summary of Worker Commute Vehicle Emissions - HECA

3/05/2013 revision

Calculations for Worker Commute Vehicle Operation

OFFSITE - 50 MPH								EF (g/mile)					
Onroad Vehicle	Fuel Type	Vehicle Type	Total Number of Workers per day	Daily Vehicle Count	Round Trip Distance (miles/vehicle/day)	Trips per day	VMT (Annual)	CO	NOx	PM_{10}	$PM_{2.5}$	SO_2	TOC
Personal Commuting Vehicles	G/D	LDA/ LDT	200	154	40.0	1	2,246,154	1.6825	0.1930	0.4234	0.1134	3.50E-03	0.0540

Assumptions:

Assumed average distance traveled off site for all employees commuting will be 20 miles

times 2 for return trip = 40 miles

365 days per year

Number of workers per commuter vehicle = 1.3

EMFAC2007 emissions are for fleet mix years 1971-2015 travelling at 50 mph.

Area	Description	CO	NOx	PM10	PM2.5	SO2	VOC
		Annual Emission Rates (tons/year) all worker commute vehicles					
San Joaquin Valley, CA	Personal Commuting Vehicles	4.17	0.48	1.05	0.28	0.01	0.13

Fugitive Dust on Paved Road

3/05/2013 revision

AP 42 13.2.1 Paved Roads, updated January 2011

For a daily basis,
E = [k (sL)^0.91 x (W)^1.02](1-P/4N) (2)

P = number of "wet" days with at least 0.254 mm (0.01 in) of precipitation during the averaging period
W = average weight (tons) of vehicles traveling the road
k = particle size multiplier for particle size range and units of interest
sL = road surface silt loading (g/m^2)

	k
	g/VMT
PM2.5	0.25
PM10	1.00

Table 13.2.1-1
PARTICLE SIZE MULTIPLIERS FOR PAVED ROAD EQUATION

Fleet mix on highway

W=	9.1	tons, average	
sL=	0.031	g/m2	Default value from URBEMIS 9.2 for Kern County
P=	36	days/year Buttonwillow Station 1940-2011, WRCC	

E=

0.09836	g/VMT PM2.5
0.39344	g/VMT PM10

Vehicle weight (tons)		fraction of each vehicle type
1.6	passenger vehicles	0.75
40	large trucks	0.18
9	2-4 axle trucks	0.07

9.1 weighted average for all vehicles (ton)

On I-5 near the Project, 75% of all vehicles are passenger vehicles,
of the remaining vehicle, 73% are 5-axle trucks and the remainder are 2-4 axle trucks.
From information provided by California Department of Transportation for the traffic analysis.

Industrial Wind Erosion, AP-42 Section 13.2.5

Emission factor (g/m^2-yr) = k Σ P_i (from i=1,N) (Equation 2) *3/05/2013 revision*

Erosion Potential (P_i) (g/m^2) = 58 (u* - u_t*)^2 + 25(u* - u_t*) (Equation 3)

0.5	k =	PM_{10} particle size multiplier
0.075	k =	$PM_{2.5}$ particle size multiplier
1	N =	number of disturbances per year
33.76	A =	exposed area of coal, m^2, per car (Table 4.1, Jan 2008 Connell Hatch: exposed area = 33.76 m^2)

Use Equation (1) to determine friction velocity:

$u(z) = u^* / 0.4 \times \ln(z/z_0)$

17.88	u(z) =	fastest mile (m/s) (based on speed of train)
0.2	z =	distance at which wind speed is measured (m) (based on the height above the coal cars at which wind flow would be laminar; assumed this height is equal to the difference between the height of the locomotive engine and the trailing coal cars)
0.003	z_0 =	roughness height for uncrusted coal pile (m), from Table 13.2.5-2
1.70	u* =	friction velocity (m/s), solved for using Equation 1
0.55	u_t* =	threshold friction velocity (m/s); Table 13.2.5-2 value for ground coal (surrounding coal pile)

Erosion Potential

	P =	105.9	g/m^2	erosion potential corresponding to the observed (or probable) fastest mile of wind for the ith period between disturbances, g/m^2
Annual	A =	442,256.0	m^2/yr	exposed area of coal per car (m^2) times number of cars per year

Unmitigated Emissions

Emission factor (g/m^2-yr) = k Σ P_i (from i=1,N)

E =	23,423,432	grams PM_{10} / year
	25.82	tons PM_{10} / year
E =	3,513,515	grams $PM_{2.5}$ / year
	3.87	tons $PM_{2.5}$ / year

Mitigation Efficiency of Surfactant: 85%

* HECA will be requiring the coal supplier to apply a surfactant to the coal transported by rail to reduce fugitive losses during transport. Surfactant achieves at least an 85% control efficiency.

Mitigated PM_{10}: 3.87 tons PM_{10} / year

Mitigated $PM_{2.5}$: 0.58 tons $PM_{2.5}$ / year

* It has been assumed that all emitted PM will be lost during the first 100 miles of the trip and has thus all been assigned to New Mexico. Maximum train speed (and thus wind speed) will certainly be reached within this time, and according to AP-42 Section 13.2.5.1, "particulate emission rates tend to decay rapidly (half-life of a few minutes) during an erosion event."

40	train speed, mph
0.447	m/s per 1 mph
453.6	grams per pound
2000	pounds per ton
13,100	Required rail car loads per year at normal operation (cars/yr)

Summary of Transportation Vehicles and Routes

3/05/2013 revision

Commodity Handled	Petcoke	Coal	Liquid Sulfur	Gasification Solids	Urea	UAN-32	Equipment Maintenance (1)	Miscellaneous Activities (2)
Expected plant operation								
Expected plant operation is 8000 hours / year								
The plant will operate 24 hours / day	24 hours / day	24 hours / day	24 hours / day	24 hours / day	24 hours / day	24 hours / day	24 hours / day	24 hours / day
The plant will operate 333 days / year	333 days / yr	333 days / yr	333 days / yr	333 days / yr	333 days / yr	333 days / yr	333 days / yr	333 days / yr
Shipment by trucks	100 %	0 %	75 %	25 %	25 %	50 %	100 %	100 %
Shipment by train	0 %	100 %	25 %	75 %	75 %	50 %	0 %	0 %
Production rate								
Required Normal Flow / day	1,140 tons / day	4,580 tons / day	100 tons / day	950 tons / day	1,720 tons / day	1,400 tons / day		
Required Normal Flow / year	380,000 tons / yr	1,526,000 tons / yr	34,000 tons / yr	317,000 tons / yr	573,000 tons / yr	467,000 tons / yr		
Required Maximum Flow day	2,000 tons / day (3)	6,500 tons / day (4)	200 tons / day (5)	1,900 tons / day (6)	3,440 tons / day (6)	2,800 tons / day (6)		
Truck Shipments								
Truck Capacity	25 tons / truck		25 tons / truck	25 tons / truck	25 tons / truck	25 tons / truck	25 tons / truck	25 tons / truck
Required trucks loads for normal operation / day	46 trucks / day		3 trucks / day	10 trucks / day	18 trucks / day	28 trucks / day	3 trucks / day	11 trucks / day
Required trucks loads for normal operation / yr	15,200 truck / yr		1,020 truck / yr	3,170 truck / yr	5,730 truck / yr	9,340 truck / yr	1,000 truck / yr	3,690 truck / yr
Required trucks loads for maximum operation /day	80 trucks / day		6 trucks / day	19 trucks / day	35 trucks / day	56 trucks / day	5 trucks / day	17 trucks / day
Train Shipments								
Railcar Capacity		117 tons / car	100 tons / car	100 tons / car	100 tons / car	100 tons / car		
Required railcars for normal operation / day		40 cars / day	0.25 cars / day	8 cars / day	13 cars / day	7 cars / day		
Required railcar loads for normal operation / yr		13,100 cars / yr	85 cars / yr	3,170 cars / yr	4,298 cars / yr	2,335 cars / yr		
Required railcars for maximum operation / day		200 cars / day	1 cars / day	19 cars / day	26 cars / day	14 cars / day		
Basis	- 91% availability - 25% petcoke (heat input) per year - 25 ton/truck - 7 days/week receiving - 25% excess truck movement capacity	- 91% availability - 75% coal (heat input) per year - 117 tons/car - 100% coal for maximum - Rack sized to handle two trains/day -	- 91% availability - High sulfur case - 100 tons/day - 25 ton/truck - Weekdays only - Can only move up to 25% of production by rail	- 91% availability - 75% coal max annual average - 100% capable by rail - 25% capable by truck - Maximun is double the daily average rate	- 91% availability - 75% by rail -empty 45 day storage in 10 days	- 91% availability - 75% by rail -empty 45 day storage in 10 days		
Traffic route	Truck Route	Truck Route	Truck Route	Truck Route	Truck Route	Truck Route	Truck Route	Truck Route
Destination/Origin Address Distance Route	Carson Refinery 1801 E Sepulveda, Carson 140 Miles Alameda 405 Fwy 5 Fwy Stockdale hwy Morris Road Station Road Station Road	None	California Sulfur 2509 E Grant Street, Wilmington 142 Miles Grant Henry Ford Alameda 405 Fwy 5 Fwy Stockdale hwy Morris Road Station Road	Various 80 Mile radius 40 mile radius Station Road Morris Road Stockdale Hywy 5 Fwy	Various 40 mile radius Station Road Morris Road Stockdale Hywy 5 Fwy	Various 40 mile radius Station Road Morris Road Stockdale Hywy 5 Fwy	Various 40 mile radius 5 fwy Stockdale Hwy Dairy Road	Various 40 mile radius 5 fwy Stockdale Hwy Dairy Road
Rail Route	Rail Route	Rail Route	Rail Route	Rail Route	Rail Route	Rail Route	Rail Route	Rail Route
Destination/Origin Address Distance Route	None	Elk Ranch New Mexico 794 miles Kern County: 132.2 miles (County Line near Boron, CA to north prop Mine to Boron, CA: 662 miles Total Distance: 794.2 miles	In SJVAPCD	CEMEX, Victorville 198 miles SJVR/BNSF	Oregon/Washington 628 Miles SJVR/UPRR	Calamco Port Rd G15, Stockton, CA 264 miles	None	None

Notes

1) Equipment Maintenance Trucks are considered to be 2% of the total trucks per day for the feed and product operation.
2) Miscellaneous trucks are considered to be 3% of the total trucks per day for the feed and product operation plus a small number of additional trucks to provide additives to the gasification.
3) The maximum flow rate of coke is ratioed up from the normal flow rate at 25% to 30% of feed
4) The maximum daily transfer rate of coal is based on supplying 7-days of normal coal required feed (75% of feedstock on a heat input basis) in 5 days and rounded upward to 2 significant figures.
5) The maximum flow rate of sulfur is 2 times the normal production
6) The maximum flow rate of these commodities is 2 times the normal production
7) The sources of flow data used in the Production Rate calculation were based on the flow rates provided in "Conference Note: Rail and Truck Traffic - Planning Session" and the "FertilizerProductMovement Update", 01-25-12.

Calculations for Trucks Operation onsite

Assumed Number of Unit Trains (incoming/outgoing)

Averaging Period	Coal Unit Trains (incoming)	Unit Trains of Product (outgoing)	Maximum Total Trains per period
Annual average unit trains	119	165	284
# Cars Per train	111	60	
maximum # Cars Per day	200-240	42-46	

	Switching Enigne/ Rail car movers	Line-Haul Engine for Coal Train	Line-Haul Engine for Product Trains
Engine Power Rating (hp)		4400	3000
Notch Operation		1	1
Notch percentage of hp		5.0%	5.0%
Avg Notch horsepower	260	220	150
# of engines per train	1	2	2
hours to unload/load each train		2	1
max operating hours (hrs/day)	8		
max operating hours (hrs/year)	1248		

The majority of the time the line-haul engine will operate in Notch 1 or idling, therefore emissions were conservatively estimated for Notch 1 horsepower.

Notch percentage presented in PORT OF LONG BEACH AIR EMISSIONS INVENTORY for 2007 (POLB, Jan 2009) derived from EPA data.

For each coal train it takes 2 hours to complete the onsite loop to unload

For each product train it takes 1 hour to load

	CO	NOx	PM10	PM2.5	SO2	VOC
Switching Engine Emission Factors						
Tier 3 Emission Factor (g/bhp-hr)	1.83	4.50	0.08	0.08	0.12	0.27
Emissions (lbs/hr /engine)	1.05	2.58	0.05	0.04	0.07	0.16
Line-Haul Emission Factors						
Tier 3 Emission Factor (g/bhp-hr)	1.28	4.95	0.08	0.08	0.09	0.14
Coal Train Emissions (lbs/hr /engine)	0.62	2.40	0.04	0.04	0.04	0.07
Product Train Emissions (lbs/hr /engine)	0.42	1.64	0.03	0.03	0.03	0.05

Annual Emission Rates in tons/year

	CO	NOx	PM10	PM2.5	SO2	VOC
Switching engines	0.65	1.61	0.03	0.03	0.04	0.10
Line-haul coal engines	0.15	0.57	0.01	0.01	0.01	0.02
Line-haul product engines	0.07	0.27	0.00	0.00	0.00	0.01

Emission Factors For all Locomotives

SOx
g/gal
1.88

Locomotive Application	Conversion Factor (bhp-hr/gal)
Large Line-haul & Passenger	20.8
Small Line-haul	18.2
Switching	15.2

Notes:

New line-haul engines will be AC locomotives such as the GE Evolution Series, that meet Tier 3 emissions

New switching engines will meet Tier 3 emissions, they may be the Titan Trackmobile railcar movers or similar

Emission factors from EPA's Technical Highlights: Emission Factors for Locomotives, 2009 (http://www.epa.gov/nonroad/locomotv/420f09025.pdf).

SO2 emissions Based on 300 ppm sulfur diesel fuel.

VOC emissions can be assumed to be equal to 1.053 times the HC emissions

$PM_{2.5}$ Fraction of PM_{10}, = 0.97

Line-haul engine emissions of CO, NOx, PM, and HC are based on EPA Tier 2+ and Tier 3 emission factors.

Calculations for Trucks Operation onsite

Data Supplied By Client					
Parameter	**Petcoke Trucks**		**Product Trucks**		**Miscellaneous Trucks**
	Running Emissions	**Idling Emissions**	**Running Emissions**	**Idling Emissions**	**Running Emissions**
Distance Traveled (mi)*	0.96		2.49		2.20
Per Truck Idle Time (hr)		0.083		0.083	
Maximum number of trucks or loads:					
Annual average trucks or loads	15,200	15,200	19,260	19,260	4,690

EMFAC2007 Emission Factors + Fugitive Dust (g/mi or g/idle-hour) For Truck Model year 2010

	Petcoke Trucks		**Product Trucks**		**Miscellaneous Trucks**
Pollutant	**Running Emissions (g/mile/trk)**	**Idling Emissions (g/idle-hour/trk)**	**Running Emissions (g/mile/trk)**	**Idling Emissions (g/idle-hour/trk)**	**Running Emissions (g/mile/trk)**
CO	3.03	43.69	3.03	43.69	3.03
NOx	5.43	122.65	5.43	122.65	5.43
ROG	1.39	7.74	1.39	7.74	1.39
SOx	0.03	0.06	0.03	0.06	0.03
PM10 *	0.92	0.11	0.92	0.11	0.92
PM2.5 *	0.29	0.10	0.29	0.10	0.29

EMFAC2007 is the approved federal model for vehicle combustion emissions
* PM10 and PM2.5 includes fugitive dust factor for paved roads obtained from AP-42 Ch. 13 plus PM factors from EMFAC 2007
PM factors from EMFAC = combustion exhaust + tire wear + break wear
EMFAC emissions are for fleet year 2010 travelling at 10 mph.

Annual Emission Rates in g/s For All Trucks

	Petcoke Trucks		**Product Trucks**		**Miscellaneous Trucks**		
Pollutant	**Running Emissions**	**Idling Emissions (at each Idle Point)**	**Running Emissions**	**Idling Emissions (at each Idle Point)**	**Running Emissions**	**TOTAL (g/s)**	**TOTAL (tpy)**
CO	1.40E-03	1.755E-03	4.596E-03	2.224E-03	9.906E-04	1.10E-02	3.81E-01
NOx	2.501E-03	4.926E-03	8.238E-03	6.242E-03	1.775E-03	2.37E-02	8.23E-01
ROG	6.398E-04	3.110E-04	2.107E-03	3.941E-04	4.541E-04	3.91E-03	1.36E-01
SOx	1.383E-05	2.490E-06	4.554E-05	3.155E-06	9.814E-06	7.48E-05	2.60E-03
PM10	4.226E-04	4.579E-06	1.392E-03	5.802E-06	3.000E-04	2.12E-03	7.39E-02
PM2.5	1.348E-04	4.177E-06	4.440E-04	5.293E-06	9.568E-05	6.84E-04	2.38E-02

Volume, Line Sources

Guidance for Air Dispersion Modeling, SJVAPCD, 2007 and Section 1.2.2 of Volume II of ISC User's Guide			
2.3.2 Oyo=12W/2.15			
Truck Traveling vol src		Truck Idling pt src	
6	ft Release height	12.6	ft Release height
12	ft Width	0.1	m diam
66.98	ft init horz dim Syo	51.71	m/s vel
5.58	ft init vert dim Szo	366	K Temp
		199.134	F Temp

Volume, Stand Alone

Guidance for Air Dispersion Modeling, SJVAPCD, 2007	
2.3.2 + modelers judgement + ISC guidance	
Truck Traveling vol src	
6	ft Release height
12	ft Width
2.79	ft init horz dim Syo
5.58	ft init vert dim Szo

Summary of On-Site Operations Truck Emissions — Emissions Summary

3/05/2013 revision

Calculations for Trucks Operation onsite

Transportation Information			**Notes**
- Onsite Vehicle =	20	trucks	- Information Provided By Applicant
- Vehicle year=	2010		- Information Provided By Applicant
- Maximum annual mileage =	10,000	miles/truck-year	- All routine vehicular traffic is anticipated to travel exclusively on paved roads
			- Assumed 15 mph average speed within HECA facility

EMFAC2007 Emission Factors (g/mi) For Truck Model year 2010

	Emission Factors in g/mi	
Pollutant	**Gas LHDT1**	**Diesel LHDT2**
CO	0.229	0.920
NOx	0.064	0.672
ROG	0.014	0.085
SOx	0.011	0.005
PM10 *	0.167	0.176
PM2.5 *	0.054	0.062

EMFAC2007 is the approved federal model for vehicle combustion emissions
* PM10 and PM2.5 includes fugitive dust factor for paved roads obtained from AP-42 Ch. 13 plus PM factors from EMFAC 2007
PM factors from EMFAC = combustion exhaust + tire wear + break wear
EMFAC emissions are for fleet year 2010 travelling at 15 mph.

Annual Emission Rates in g/s From All Trucks

	Emissions in g/s			
Pollutant	**Gas LHDT1**	**Diesel LHDT2**	**TOTAL (g/s)**	**TOTAL (tpy)**
CO	1.45E-03	5.83E-03	7.29E-03	0.253
NOx	4.06E-04	4.26E-03	4.67E-03	0.162
ROG	8.88E-05	5.39E-04	6.28E-04	0.022
SOx	6.98E-05	3.17E-05	1.01E-04	0.004
PM10	1.06E-03	1.11E-03	2.17E-03	0.076
PM2.5	3.40E-04	3.91E-04	7.32E-04	0.025

Fugitive Dust on Paved Road

3/05/2013 revision

AP 42 13.2.1 Paved Roads, updated January 2011

Calculations for Trucks Operation onsite

For a daily basis,

E = [k (sL)^0.91 x (W)^1.02](1-P/4N) (2)

P = number of "wet" days with at least 0.254 mm (0.01 in) of precipitation during the averaging period
W = average weight (tons) of vehicles traveling the road
k = particle size multiplier for particle size range and units of interest
sL = road surface silt loading (g/m^2)

	k
	g/VMT
PM2.5	0.25
PM10	1.00

Table 13.2.1-1
PARTICLE SIZE MULTIPLIERS FOR PAVED ROAD EQUATION

Large Trucks

			Empty truck	full truck	Load Capacity	
W=	17.5	tons, average	5	30	0	tons
sL=	0.031	g/m2 Default value from URBEMIS 9.2 for Kern County				
P=	36	days/year Buttonwillow Station 1940-2011, WRCC				

E=

0.19149 g/VMT PM2.5 large delivery trucks
0.76594 g/VMT PM10 large delivery trucks

Operation and Maintenance Vehicles

W=	3	tons
sL=	0.031	g/m2 Default value from URBEMIS 9.2 for Kern County
P=	36	days/year Buttonwillow Station 1940-2011, WRCC

E=

0.03169 g/VMT PM2.5 O&M trucks
0.12675 g/VMT PM10 O&M trucks

APPENDIX C

DETAILED OPERATIONAL EMISSION CALCULATIONS FOR ALTERNATIVE 2

Summary of Applicable Operational Emissions for General Conformity (Alternative 2) - 2017 Overlapping with Construction

Hydrogen Energy California LLC
HECA Project

3/05/2013 revision

Federal NAAQS Nonattainment or Maintenance Area General Name and State	Detailed Status in Nonattainment or Maintenance Area	Authority Agency	Basis to Estimate the Offsite Transportation Distance	Emission Sources / Applicable General Conformity Thresholds / Comparisons	Project Operational Annual Emission Rates - for General Conformity (tpy)					
					CO	NOx	PM10	PM2.5	SO2	VOC
San Joaquin Valley, CA	8-Hour Ozone (2008) Nonattainment - Extreme PM2.5 Nonattainment CO Maintenance - Maderate - Fresno, CA (Part of Fresno County), Modesto, CA (Part of Stanislaus County), Stockton, CA (Part of San Joaquin County) PM10 Maintenance	SJVAPCD	**Construction** - Entire SJVAPCD jurisdiction area (one way trip: trucks = worker vehicles = 20 miles)	Onsite Construction Equipmen	2.65	3.84	0.48	0.27	0.00	0.83
				Onsite Trucks	0.15	0.34	0.09	0.03	0.00	0.09
				Onsite Vehicles	0.08	0.01	0.22	0.02	0.00	0.01
				Onsite Total	**2.88**	**4.18**	**0.79**	**0.32**	**0.01**	**0.93**
				Offsite Linears Equipment	0.00	0.00	0.00	0.00	0.00	0.00
				Offsite Trucks	1.02	5.16	0.42	0.21	0.00	0.22
				Offsite Vehicles	5.98	0.72	0.20	0.07	0.01	0.18
				Offsite Total	**6.99**	**5.87**	**0.61**	**0.28**	**0.01**	**0.41**
				Total Construction Emission	**9.87**	**10.06**	**1.40**	**0.60**	**0.02**	**1.34**
			Operation - Entire SJVAPCD jurisdiction area (one way trip: trains = 70 miles, trucks = 26.5 to 80 miles, workers= 20 miles)	Offsite Train	1.25	4.82	0.08	0.08	0.09	0.13
				Offsite Truck	5.20	8.56	2.35	0.71	0.06	0.72
				Offsite Workers Commuting	1.39	0.16	0.35	0.09	0.00	0.04
				Onsite Train	0.00	0.00	0.00	0.00	0.00	0.00
				Onsite Truck	0.51	0.99	0.10	0.03	0.00	0.15
				Total Operation Emissions	**8.34**	**14.53**	**2.88**	**0.91**	**0.16**	**1.05**
				Total Construction and Operation Overlapping Emissions	**18.21**	**24.59**	**4.28**	**1.51**	**0.17**	**2.39**
				Applicable General Conformity *de minimis* Thresholds	**100**	**10**	**100**	**100**	**100**	**10**
				Less Than Thresholds?	**Yes**	**No**	**Yes**	**Yes**	**Yes**	**Yes**
Los Angeles-South Coast Air Basin, CA	8-Hour Ozone (2008) Nonattainment - Extreme PM10 Nonattainment - Serious PM2.5 Nonattainment NO2 Maintenance CO Maintenance - Serious	SCAQMD	Entire SCAQMD jurisdiction area (one way trip: trucks = 88 to 150 miles)	Offsite Train	0.00	0.00	0.00	0.00	0.00	0.00
				Offsite Truck	1.75	2.89	0.79	0.24	0.02	0.24
				Total Emission	**1.75**	**2.89**	**0.79**	**0.24**	**0.02**	**0.24**
				Conformity De minimis (ton/yr)	**100**	**10**	**70**	**100**	**100**	**10**
				Less than De minimis?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Kern County (East Kern), CA	8-Hour Ozone (2008) Nonattainment - Marginal PM10 Nonattainment - Serious	EKAPCD	Entire EKAPCD jurisdiction area (one way trip: trains = 62 miles)	Offsite Train		4.27	0.07			0.12
				Offsite Truck		0.00	0.00			0.00
				Total Emission		**4.27**	**0.07**			**0.12**
				Conformity De minimis (ton/yr)		**100**	**70**			**100**
				Less than De minimis?		**Yes**	**Yes**			**Yes**
Los Angeles-San Bernardino Counties (West Mojave Desert), CA	8-Hour Ozone (2008) Nonattainment - Severe 15 (Part of San Bernardino and Los Angeles Counties)	MDAQMD	Los Angeles-San Bernardino Counties (West Mojave Desert) - 8-hr Ozone (2008) NAA (one way trip: trains = 120 miles)	Offsite Train		8.27				0.23
				Offsite Truck		0.00				0.00
				Total Emission		**8.27**				**0.23**
				Conformity De minimis (ton/yr)		**25**				**25**
				Less than De minimis?		**Yes**				**Yes**
San Bernardino County, CA (Mojave Desert)	PM10 Nonattainment - Moderate	MDAQMD	Entire MDAQMD jurisdiction area (one way trip: trains = 204 miles)	Offsite Train			0.23			
				Offsite Truck			0.00			
				Total Emission			**0.23**			
				Conformity De minimis (ton/yr)			**100**			
				Less than De minimis?			**Yes**			
Sacramento Metro, CA	8-Hour Ozone (2008) Nonattainment - Severe 15 PM10 Nonattainment - Moderate (Sacramento County) PM2.5 Nonattainment CO Maintenance - Moderate - Sacramento, CA (Part of Placer, Sacramento and Yolo Counties)	SMAQMD	Entire SMAQMD jurisdiction area (one way trip: trains = 0 miles)	Offsite Train	0.00	0.00	0.00	0.00	0.00	0.00
				Offsite Truck	0.00	0.00	0.00	0.00	0.00	0.00
				Total Emission	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
				Conformity De minimis (ton/yr)	**NA**	**25**	**100**	**100**	**100**	**25**
				Less than De minimis?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Yuba City-Marysville, CA	PM2.5 Nonattainment (Sutter and Part of Yuba Counties) 1-Hour Ozone (Yuba City)	FRAQMD	Yuba City-Marysville, CA - PM2.5 NAA (one way trip: trains = 0 miles)	Offsite Train		0.00		0.00	0.00	0.00
				Offsite Truck		0.00		0.00	0.00	0.00
				Total Emission		**0.00**		**0.00**	**0.00**	**0.00**
				Conformity De minimis (ton/yr)		**100**		**100**	**100**	**100**
				Less than De minimis?		**Yes**		**Yes**	**Yes**	**Yes**
Chico, CA	8-Hour Ozone (2008) Nonattainment - Marginal (Butte County) PM2.5 Nonattainment (Part of Butte County) CO Maintenance - Moderate (Part of Butte County)	BCAQMD	Chico, CA - 8-Hour Ozone (2008) NAA - Entire Butte County (one way trip: trains = 0 miles)	Offsite Train	0.00	0.00		0.00	0.00	0.00
				Offsite Truck	0.00	0.00		0.00	0.00	0.00
				Total Emission	**0.00**	**0.00**		**0.00**	**0.00**	**0.00**
				Conformity De minimis (ton/yr)	**NA**	**100**		**100**	**100**	**100**
				Less than De minimis?	**Yes**	**Yes**		**Yes**	**Yes**	**Yes**

Summary of Applicable Operational Emissions for General Conformity (Alternative 2) - 2017 Overlapping with Construction

Hydrogen Energy California LLC
HECA Project

3/05/2013 revision

Federal NAAQS Nonattainment or Maintenance Area General Name and State	Detailed Status in Nonattainment or Maintenance Area	Authority Agency	Basis to Estimate the Offsite Transportation Distance	Emission Sources / Applicable General Conformity Thresholds / Comparisons	Project Operational Annual Emission Rates - for General Conformity (tpy)					
					CO	**NOx**	**PM10**	**PM2.5**	**SO2**	**VOC**
NAAs in State of Arizona	8-Hour Ozone (2008) Nonattainment - Marginal - Phoenix-Mesa, AZ (Part of Maricopa and Pinal County) PM10 Nonattainment (Moderate, Serious, or Maintenance) (12 Counties) PM2.5 Nonattainment - Nogales, AZ (Part of Santa Cruz County), West Central Pinal, AZ (West Pinal County) SO2 Nonattainment - Hayden (Pinal County), AZ (Part of Pinal County), Maintenance - San Manual (Pinal County), AZ, Ajo (Pima County), AZ, Douglas (Cochise County), AZ, Miami (Gila County), AZ CO Maintenance - Serious - Phoenix, AZ. (Part of Maricopa)	ADEQ	Entire ADEQ jurisdiction area (one way trip: trains = 364 miles)	Offsite Train	6.48	25.08	0.41	0.39	0.46	0.69
				Offsite Truck	0.00	0.00	0.00	0.00	0.00	0.00
				Total Emission	**6.48**	**25.08**	**0.41**	**0.39**	**0.46**	**0.69**
				Conformity De minimis (ton/yr)	**100**	**100**	**70**	**100**	**100**	**100**
				Less than De minimis?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
NAAs in State of New Mexico	PM10 Nonattainment - Moderate - Anthony, NM (Dona Ana County) CO Maintenance (Bernalillo County) SO2 Maintenance - Grant Co, NM	NMED-AQB	Entire NMED-AQB jurisdiction area (one way trip: trains = 102 miles to coal mine site)	Offsite Train	1.81		1.40		0.13	
				Offsite Truck	0.00		0.00		0.00	
				Total Emission	**1.81**		**1.40**		**0.13**	
				Conformity De minimis (ton/yr)	**100**		**100**		**100**	
				Less than De minimis?	**Yes**		**Yes**		**Yes**	

Notes:

1. The associated emissions from the onsite worker travel are negligible
2. To simplify the analysis, the biggest area among all detailed NAA areas was conservativly used to estimate the emissions in each main NAA category area.
   For State of Arizona and New Mexico the total distances accross each state along the train routes were conservativly used to estimate the emissions in NAA.
3. The distance for trains and trucks are varied depending on the type to materials transporting and their destinations.

ozone nonattainment area is smaller than the distance in PM10 nonattainment area.

5. ACRONYMS AND ABBREVIATIONS
   MDAQMD = Mojave Desert Air Quality Management District
   SCAQMD = South Coast Air Quality Management District
   EKAPCD = East Kern County Air Pollution Control District
   SMAQMD = Sacramento Metro Air Quality Management District
   BCAQMD = Butte County Air Quality Management District
   FRAQMD = Feather River Air Quality Management District
   ADEQ = Arizona Department of Environmental Quality
   NMED-AQB = New Mexico Environment Department - Air Quality Bureau
6. Construction of the project is expected to complete in June 2017 and the operation will start from September. Therefore, the operational emissions were scaled from the entire year of project operation.

Summary of Applicable Operational Emissions for General Conformity (Alternative 2) - 2018 and Beyond

Hydrogen Energy California LLC — *3/05/2013 revision*
HECA Project

Federal NAAQS Nonattainment or Maintenance Area General Name and State	Detailed Status in Nonattainment or Maintenance Area	Authority Agency	Basis to Estimate the Offsite Transportation Distance	Emission Sources / Applicable General Conformity Thresholds / Comparisons	Project Operational Annual Emission Rates - for General Conformity (tpy)					
					CO	NOx	PM10	PM2.5	SO2	VOC
San Joaquin Valley, CA	8-Hour Ozone (2008) Nonattainment - Extreme PM2.5 Nonattainment CO Maintenance - Maderate - Fresno, CA (Part of Fresno County), Modesto, CA (Part of PM10 Maintenance	SJVAPCD	Entire SJVAPCD jurisdiction area (one way trip: trains = 70 miles, trucks = 26.5 to 80 miles, workers= 20 miles)	Offsite Train	3.74	14.47	0.23	0.23	0.26	0.40
				Offsite Truck	15.59	25.67	7.05	2.12	0.19	2.17
				Offsite Workers Commuting	4.17	0.48	1.05	0.28	0.01	0.13
				Onsite Train	0.00	0.00	0.00	0.00	0.00	0.00
				Onsite Truck	1.52	2.97	0.30	0.10	0.01	0.45
				Total Emission	**25.02**	**43.59**	**8.64**	**2.73**	**0.47**	**3.16**
				Conformity De minimis (ton/yr)	**100**	**10**	**100**	**100**	**100**	**10**
				Less than De minimis?	**Yes**	**No**	**Yes**	**Yes**	**Yes**	**Yes**
Los Angeles-South Coast Air Basin, CA	8-Hour Ozone (2008) Nonattainment - Extreme PM10 Nonattainment - Serious PM2.5 Nonattainment NO2 Maintenance CO Maintenance - Serious	SCAQMD	Entire SCAQMD jurisdiction area (one way trip: trucks = 88 to 150 miles)	Offsite Train	0.00	0.00	0.00	0.00	0.00	0.00
				Offsite Truck	5.26	8.67	2.38	0.72	0.06	0.73
				Total Emission	**5.26**	**8.67**	**2.38**	**0.72**	**0.06**	**0.73**
				Conformity De minimis (ton/yr)	**100**	**10**	**70**	**100**	**100**	**10**
				Less than De minimis?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Kern County (East Kern), CA	8-Hour Ozone (2008) Nonattainment - Marginal PM10 Nonattainment - Serious	EKAPCD	Entire EKAPCD jurisdiction area (one way trip: trains = 62 miles)	Offsite Train		12.81	0.21			0.35
				Offsite Truck		0.00	0.00			0.00
				Total Emission		**12.81**	**0.21**			**0.35**
				Conformity De minimis (ton/yr)		**100**	**70**			**100**
				Less than De minimis?		**Yes**	**Yes**			**Yes**
Los Angeles-San Bernardino Counties (West Mojave Desert), CA	8-Hour Ozone (2008) Nonattainment - Severe 15 (Part of San Bernardino and Los Angeles Counties)	MDAQMD	Los Angeles-San Bernardino Counties (West Mojave Desert) - 8-hr Ozone (2008) NAA (one way trip: trains = 120 miles)	Offsite Train		24.80				0.69
				Offsite Truck		0.00				0.00
				Total Emission		**24.80**				**0.69**
				Conformity De minimis (ton/yr)		**25**				**25**
				Less than De minimis?		**Yes**				**Yes**
San Bernardino County, CA (Mojave Desert)	PM10 Nonattainment - Moderate	MDAQMD	Entire MDAQMD jurisdiction area (one way trip: trains = 204 miles)	Offsite Train			0.68			
				Offsite Truck			0.00			
				Total Emission			**0.68**			
				Conformity De minimis (ton/yr)			**100**			
				Less than De minimis?			**Yes**			
Sacramento Metro, CA	8-Hour Ozone (2008) Nonattainment - Severe 15 PM10 Nonattainment - Moderate (Sacramento County) PM2.5 Nonattainment CO Maintenance - Moderate - Sacramento, CA (Part of Placer, Sacramento and Yolo Counties)	SMAQMD	Entire SMAQMD jurisdiction area (one way trip: trains = 0 miles)	Offsite Train	0.00	0.00	0.00	0.00	0.00	0.00
				Offsite Truck	0.00	0.00	0.00	0.00	0.00	0.00
				Total Emission	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
				Conformity De minimis (ton/yr)	**NA**	**25**	**100**	**100**	**100**	**25**
				Less than De minimis?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Yuba City-Marysville, CA	PM2.5 Nonattainment (Sutter and Part of Yuba	FRAQMD	Yuba City-Marysville, CA - PM2.5 NAA (one way trip: trains = 0 miles)	Offsite Train		0.00		0.00	0.00	0.00
				Offsite Truck		0.00		0.00	0.00	0.00
				Total Emission		**0.00**		**0.00**	**0.00**	**0.00**
				Conformity De minimis (ton/yr)		**100**		**100**	**100**	**100**
				Less than De minimis?		**Yes**		**Yes**	**Yes**	**Yes**
Chico, CA	8-Hour Ozone (2008) Nonattainment - Marginal (Butte County) PM2.5 Nonattainment (Part of Butte County) CO Maintenance - Moderate (Part of Butte County)	BCAQMD	Chico, CA - 8-Hour Ozone (2008) NAA - Entire Butte County (one way trip: trains = 0 miles)	Offsite Train	0.00	0.00		0.00	0.00	0.00
				Offsite Truck	0.00	0.00		0.00	0.00	0.00
				Total Emission	**0.00**	**0.00**		**0.00**	**0.00**	**0.00**
				Conformity De minimis (ton/yr)	**NA**	**100**		**100**	**100**	**100**
				Less than De minimis?	**Yes**	**Yes**		**Yes**	**Yes**	**Yes**

Summary of Applicable Operational Emissions for General Conformity (Alternative 2) - 2018 and Beyond

Hydrogen Energy California LLC *3/05/2013 revision*
HECA Project

Federal NAAQS Nonattainment or Maintenance Area General Name and State	Detailed Status in Nonattainment or Maintenance Area	Authority Agency	Basis to Estimate the Offsite Transportation Distance	Emission Sources / Applicable General Conformity Thresholds / Comparisons	Project Operational Annual Emission Rates - for General Conformity (tpy)					
					CO	NOx	PM10	PM2.5	SO2	VOC
NAAs in State of Arizona	8-Hour Ozone (2008) Nonattainment - Marginal - Phoenix-Mesa, AZ (Part of Maricopa and Pinal County) PM10 Nonattainment (Moderate, Serious, or Maintenance) (12 Counties) PM2.5 Nonattainment - Nogales, AZ (Part of Santa Cruz County), West Central Pinal, AZ (West Pinal County) SO2 Nonattainment - Hayden (Pinal County), AZ (Part of Pinal County), Maintenance - San Manual (Pinal County), AZ, Ajo (Pima County), AZ, Douglas (Cochise County), AZ, Miami (Gila County), AZ CO Maintenance - Serious - Phoenix, AZ. (Part of Maricopa)	ADEQ	Entire ADEQ jurisdiction area (one way trip: trains = 364 miles)	Offsite Train	19.45	75.23	1.22	1.18	1.37	2.08
				Offsite Truck	0.00	0.00	0.00	0.00	0.00	0.00
				Total Emission	**19.45**	**75.23**	**1.22**	**1.18**	**1.37**	**2.08**
				Conformity De minimis (ton/yr)	**100**	**100**	**70**	**100**	**100**	**100**
				Less than De minimis?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
NAAs in State of New Mexico	PM10 Nonattainment - Moderate - Anthony, NM (Dona Ana County) CO Maintenance (Bernalillo County) SO2 Maintenance - Grant Co, NM	NMED-AQB	Entire NMED-AQB jurisdiction area (one way trip: trains = 102 miles to coal mine site)	Offsite Train	5.42		4.21		0.38	
				Offsite Truck	0.00		0.00		0.00	
				Total Emission	**5.42**		**4.21**		**0.38**	
				Conformity De minimis (ton/yr)	**100**		**100**		**100**	
				Less than De minimis?	**Yes**		**Yes**		**Yes**	

Notes:

1. The associated emissions from the onsite worker travel are negligible
2. To simplify the analysis, the biggest area among all detailed NAA areas was conservativly used to estimate the emissions in each main NAA category area.
   For State of Arizona and New Mexico the total distances accross each state along the train routes were conservativly used to estimate the emissions in NAA.
3. The distance for trains and trucks are varied depending on the type to materials transporting and their destinations.

nonattainment area is smaller than the distance in PM10 nonattainment area.

5. ACRONYMS AND ABBREVIATIONS
   MDAQMD = Mojave Desert Air Quality Management District
   SCAQMD = South Coast Air Quality Management District
   EKAPCD = East Kern County Air Pollution Control District
   SMAQMD = Sacramento Metro Air Quality Management District
   BCAQMD = Butte County Air Quality Management District
   FRAQMD = Feather River Air Quality Management District
   ADEQ = Arizona Department of Environmental Quality
   NMED-AQB = New Mexico Environment Department - Air Quality Bureau

Annual Number of Train Cars (incoming/outgoing)

	Coal Cars (incoming)	Liquid Sulfur Cars (outgoing)	Gasification Cars (outgoing)	Ammonia Cars (outgoing)	Urea Cars (outgoing)	UAN Cars (outgoing)	Maximum Total Trains per period
Annual average number of train cars	13100	0	0	0	0	0	13100

		Line-Haul Engine for Product Trains				
	Line-Haul Engine for Coal Train	Liquid Sulfur	Gasification	Ammonia	Urea	UAN
ton-mile/gallon	480	480	480	480	480	480
Train car capacity (ton)	117	100	100	0	100	100
Unloaded train car weight (ton)	25	25	25	25	25	25

480 ton-mile/gallon is based on 2009 *class I rail freight fuel consumption and travel* data (Association of American Railroads, *Railroad Facts*)

	Coal Trains			Liquid Sulfur Product Train			Gasification Solid Product Train		
Area	Miles traveled per Train (mile/engine) - One Way *	Coal Train (ton-miles/year) - Round Trip	Fuel Use for Coal Train (gal/year) - Round Trip	Miles traveled per Train (mile/engine) - One Way	Product Train (ton-miles/year) - Round Trip	Fuel Use for Product Train (gal/year) - Round Trip	Miles traveled per Train (mile/engine) - One Way	Product Train (ton-miles/year) - Round Trip	Fuel Use for Product Train (gal/year) - Round Trip
SJVAPCD	70	153,139,000	319,028	0	0	0	0	0	0
EKAPCD	62	135,637,400	282,568		0	0	0	0	0
MDAQMD (PM10 nonattainment and the maximum distance)	204	445,196,950	927,461		0	0	0	0	0
MDAQMD (Ozone nonattainment)	120	262,524,000	546,906		0	0		0	0
Arizona (PM10 nonattainment and the maximum distance)	364	796,322,800	1,658,947		0	0		0	0
New Mexico	102	222,051,550	462,591		0	0		0	0

* Since exact route of coal train was not determined yet, It was assumed that the coal train would travel across the maximum distance of the nonattainment area for all pollutants in Arizona.

	Ammonia Product Train			Urea Product Train			UAN Product Train		
Area	Miles traveled per Train (mile/engine) - One Way	Product Train (ton-miles/year) - Round Trip	Fuel Use for Product Train (gal/year) - Round Trip	Miles traveled per Train (mile/engine) - One Way	Product Train (ton-miles/year) - Round Trip	Fuel Use for Product Train (gal/year) - Round Trip	Miles traveled per Train (mile/engine) - One Way	Product Train (ton-miles/year) - Round Trip	Fuel Use for Product Train (gal/year) - Round Trip
SJVAPCD	0	0	0	0	0	0	0	0	0
Sacramento Metro		0	0	0	0	0		0	0
Yuba City-Marysville		0	0	0	0	0		0	0
Chico		0	0	0	0	0		0	0
Other Area in California and Oregon/Washington		0	0	0	0	0		0	0

offsite locomotive travelling speed in average	40	mph
ratio of required horsepower (empty train/full train)	0.76	
locomotive load factor	28%	

Train Type	Coal	Liquid Sulfur	Gasification Solids	Ammonia	Urea	UAN
Railcar Capacity (ton)	117	100	100	-	100	100
Locomotive Engine Power (hp, each)	4,400	3,000	3,000		3,000	3,000
Railcars per train	111	60	60		60	60
Numbers of locomotive engine per train	6	2	2		2	2
Total ton of material per locomotive engine	2,165	3,000	3,000		3,000	3,000
Total # locomotive engines needed to transport material per year	706	-	-		-	-
Total # locomotive engines needed for returning trains per year	536	-	-		-	-
Total locomotive hours per year in SJVAPCD	2,174					
Total locomotive hours per year in EKAPCD	1,925					
Total locomotive hours per year in MDAQMD (PM10 nonattainment and the maximum distance)	6,319					
Total locomotive hours per year in MDAQMD (Ozone nonattainment)	3,726					
Total locomotive hours per year in Arizona (PM10 nonattainment and the maximum distance)	11,303					
Total locomotive hours per year in Arizona (PM2.5 nonattainment)	621					
Total locomotive hours per year in Arizona (Ozone nonattainment)	3,105					
Total locomotive hours per year in Arizona (SO2 and CO nonattainment)	6,210					
Total locomotive hours per year in New Mexico	3,152					
Total locomotive hours per year in Sacramento Metro						
Total locomotive hours per year in Yuba City-Marysville						
Total locomotive hours per year in Chico						
Total locomotive hours per year in Other Area in California and Oregon/Washington						

	Line-Haul Emission Factors	CO	NOx	PM10	PM2.5	SO2	VOC
	Tier 3 Emission Factor (g/bhp-hr)	1.28	4.95	0.08	0.08	0.09	0.14
	Tier 3 Emission Factor (g/gal)	26.62	102.96	1.66	1.61	1.88	2.85

Summary of Offsite Operations Train Emissions - HECA

Emissions Summary

3/05/2013 revision

Annual Emission Rates by Area

Area		CO	NOx	PM10	PM2.5	SO2	VOC
		Annual Emission Rates (tons/year) all trains					
SJVAPCD (San Joaquin Valley), CA	Line-haul coal engines	3.74	14.47	0.23	0.23	0.26	0.40
	Line-haul liquid sulfur product engines	0.00	0.00	0.00	0.00	0.00	0.00
	Line-haul gasification product engines	0.00	0.00	0.00	0.00	0.00	0.00
	Line-haul ammonia product engines	0.00	0.00	0.00	0.00	0.00	0.00
	Line-haul urea product engines	0.00	0.00	0.00	0.00	0.00	0.00
	Line-haul UAN product engines	0.00	0.00	0.00	0.00	0.00	0.00
	Total Trains (ton/yr)	**3.74**	**14.47**	**0.23**	**0.23**	**0.26**	**0.40**
EKAPCD (East Kern County), CA	Line-haul coal engines	3.31	12.81	0.21	0.20	0.23	0.35
	Line-haul gasification product engines	0.00	0.00	0.00	0.00	0.00	0.00
	Total Trains (ton/yr)	**3.31**	**12.81**	**0.21**	**0.20**	**0.23**	**0.35**
MDAQMD (PM10 nonattainment and total distance)	Line-haul coal engines	10.88	42.06	0.68	0.66	0.77	1.16
	Line-haul gasification product engines	0.00	0.00	0.00	0.00	0.00	0.00
	Total Trains (ton/yr)	**10.88**	**42.06**	**0.68**	**0.66**	**0.77**	**1.16**
MDAQMD (Ozone nonattainment)	Line-haul coal engines	6.41	24.80	0.40	0.39	0.45	0.69
	Line-haul gasification product engines	0.00	0.00	0.00	0.00	0.00	0.00
	Total Trains (ton/yr)	**6.41**	**24.80**	**0.40**	**0.39**	**0.45**	**0.69**
Arizona	Line-haul coal engines	19.45	75.23	1.22	1.18	1.37	2.08
	Total Trains (ton/yr)	**19.45**	**75.23**	**1.22**	**1.18**	**1.37**	**2.08**
Sacramento Metro, CA	Line-haul urea product engines	0.00	0.00	0.00	0.00	0.00	0.00
	Total Trains (ton/yr)	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Yuba City-Marysville, CA	Line-haul urea product engines	0.00	0.00	0.00	0.00	0.00	0.00
	Total Trains (ton/yr)	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Chico, CA	Line-haul urea product engines	0.00	0.00	0.00	0.00	0.00	0.00
	Total Trains (ton/yr)	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Other Area in California and Oregon/Washington	Line-haul urea product engines	0.00	0.00	0.00	0.00	0.00	0.00
	Total Trains (ton/yr)	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
New Mexico	Line-haul coal engines	5.42	20.98	0.34	0.33	0.38	0.58
	Total Trains (ton/yr)	**5.42**	**20.98**	**0.34**	**0.33**	**0.38**	**0.58**

EPA Estimated Locomotive Average Emission Rates by Tiers

Tier	Emission Factor (g/bhp-hr)			
	CO	NO_X	PM	HC
Uncontrolled	1.28	13.00	0.32	0.48
Tier 0	1.28	8.60	0.32	0.48
Tier 0+	1.28	7.20	0.20	0.30
Tier 1	1.28	6.70	0.32	0.47
Tier 1+	1.28	6.70	0.20	0.29
Tier 2	1.28	4.95	0.18	0.26
Tier 2+ and Tier 3	1.28	4.95	0.08	0.13
Tier 4	1.28	1.00	0.015	0.04

Emission Factors For all Locomotives
SOx (3)
g/gal
1.88

Locomotive Application	Conversion Factor (bhp-hr/gal)
Large Line-haul & Passenger	20.8
Small Line-haul	18.2
Switching	15.2

Note:

(1) EPA's Technical Highlights: Emission Factors for Locomotives, 2009 (http://www.epa.gov/nonroad/locomotv/420f09025.pdf).

(2) Line-haul engine emissions of CO, Nox, PM, and HC are based on EPA Tier 3.

(3) Based on 300 ppm sulfur diesel fuel.

(4) VOC emissions can be assumed to be equal to 1.053 times the HC emissions

(5) $PM_{2.5}$ Fraction of PM_{10}, = 0.97

(6) No off-site switching or idling was assumed for train transportation.

(7) Average line haul locomotive load factor was obtained from Table 5.12 of The Port Of Long Beach - 2007 Air Emissions Inventory (http://www.polb.com/civica/filebank/blobdload.asp?BlobID=6021)

Summary of Truck Emissions - HECA

3/05/2013 revision

Calculations for Trucks Operation

Data Supplied By Client							
Parameter	Coke Trucks (Max @ 50 or 60 mph)	Coal Trucks (Max @ 50 or 60 mph)	Liquid Sulfur Product Trucks (Max @ 50 or 60 mph)	Gasification Product Trucks (Max @ 50 or 60 mph)	Urea Product Trucks (Max @ 50 or 60 mph)	UAN Sulfur Product Trucks (Max @ 50 or 60 mph)	Equipment and Miscellaneous Trucks (Max @ 50 or 60 mph)
	Running Emissions	Running Emissions	Running Emissions	Running Emissions	Running Emissions	Running Emissions	Running Emissions
Distance traveled per truck in San Joaquin Valley, CA (mi)	104	53	104	160	80	80	92
Distance traveled per truck in Los Angeles-South Coast Air Basin, CA (mi)	176	0	180	0	0	0	151
Maximum number of trucks or loads:							
Annual average trucks or loads	15,200	61,040	1,360	12,680	22,920	18,680	4,690

No off-site idling was assumed for truck transportation.
Distance traveled per truck is based on round-trip.

EMFAC2007 Emission Factors + Fugitive Dust (g/mi) For Truck Model year 2010, Scenario year 2015

Pollutant	Coke Trucks (Max @ 50 or 60 mph) Running Emissions (g/mile/trk)	Coal Trucks (Max @ 50 or 60 mph) Running Emissions (g/mile/trk)	Liquid Sulfur Product Trucks (Max @ 50 or 60 mph) Running Emissions (g/mile/trk)	Gasification Product Trucks (Max @ 50 or 60 mph) Running Emissions (g/mile/trk)	Urea Product Trucks (Max @ 50 or 60 mph) Running Emissions (g/mile/trk)	UAN Sulfur Product Trucks (Max @ 50 or 60 mph) Running Emissions (g/mile/trk)	Equipment and Miscelleneous Trucks (Max @ 50 or 60 mph) Running Emissions (g/mile/trk)
CO	1.32	1.32	1.32	1.32	1.32	1.32	1.32
NOx	2.17	2.17	2.17	2.17	2.17	2.17	2.17
ROG	0.18	0.18	0.18	0.18	0.18	0.18	0.18
SOx	0.02	0.02	0.02	0.02	0.02	0.02	0.02
PM10 *	0.60	0.60	0.60	0.60	0.60	0.60	0.60
PM2.5 *	0.18	0.18	0.18	0.18	0.18	0.18	0.18

EMFAC2007 is the approved federal model for vehicle combustion emissions
* PM10 and PM2.5 includes fugitive dust factor for paved roads obtained from AP-42 Ch. 13 plus PM factors from EMFAC 2007
PM factors from EMFAC = combustion exhaust + tire wear + break wear
The maximum emission factor from either truck speed at 50 mph or 60 mph was used.
Most California highways have speed limits of 60 or 70 mph and large trucks travel more slowly than the speed limit.

Annual Emission Rates in ton/yr all trucks

Pollutant	Coke Trucks (Max @ 50 or 60 mph) Running Emissions	Coal Trucks (Max @ 50 or 60 mph) Running Emissions	Liquid Sulfur Product Trucks (Max @ 50 or 60 Running Emissions	Gasification Product Trucks (Max @ 50 or 60 Running Emissions	Urea Product Trucks (Max @ 50 or 60 mph) Running Emissions	UAN Sulfur Product Trucks (Max @ 50 or 60 mph) Running Emissions	Equipment and Miscelleneous Trucks (Max Running Emissions	Total Truck Emission Rates (tons/yr)
San Joaquin Valley, CA								
CO	2.29	4.69	0.21	2.94	2.66	2.17	0.63	**15.59**
NOx	3.78	7.73	0.34	4.85	4.38	3.57	1.03	**25.67**
ROG	0.32	0.65	0.03	0.41	0.37	0.30	0.09	**2.17**
SOx	0.03	0.06	0.00	0.04	0.03	0.03	0.01	**0.19**
PM10	1.04	2.12	0.09	1.33	1.20	0.98	0.28	**7.05**
PM2.5	0.31	0.64	0.03	0.40	0.36	0.30	0.09	**2.12**
Los Angeles-South Coast Air Basin, CA								
CO	3.88	0.00	0.36	0.00	0.00	0.00	1.03	**5.26**
NOx	6.39	0.00	0.58	0.00	0.00	0.00	1.69	**8.67**
ROG	0.54	0.00	0.05	0.00	0.00	0.00	0.14	**0.73**
SOx	0.05	0.00	0.00	0.00	0.00	0.00	0.01	**0.06**
PM10	1.76	0.00	0.16	0.00	0.00	0.00	0.46	**2.38**
PM2.5	0.53	0.00	0.05	0.00	0.00	0.00	0.14	**0.72**

Summary of Worker Commute Vehicle Emissions - HECA

3/05/2013 revision

Calculations for Worker Commute Vehicle Operation

OFFSITE - 50 MPH								EF (g/mile)					
Onroad Vehicle	Fuel Type	Vehicle Type	Total Number of Workers per day	Daily Vehicle Count	Round Trip Distance (miles/vehicle/day)	Trips per day	VMT (Annual)	CO	NOx	PM_{10}	$PM_{2.5}$	SO_2	TOC
Personal Commuting Vehicles	G/D	LDA/ LDT	200	154	40.0	1	2,246,154	1.6825	0.1930	0.4234	0.1134	3.50E-03	0.0540

Assumptions:

Assumed average distance traveled off site for all employees commuting will be 20 miles

times 2 for return trip = 40 miles

365 days per year

Number of workers per commuter vehicle = 1.3

EMFAC2007 emissions are for fleet mix years 1971-2015 travelling at 50 mph.

Area	Description	Annual Emission Rates (tons/year) all worker commute vehicles					
		CO	NOx	PM10	PM2.5	SO2	VOC
San Joaquin Valley, CA	Personal Commuting Vehicles	4.17	0.48	1.05	0.28	0.01	0.13

Fugitive Dust on Paved Road

3/05/2013 revision

AP 42 13.2.1 Paved Roads, updated January 2011

For a daily basis,
E = [k (sL)^0.91 x (W)^1.02](1-P/4N) (2)

P = number of "wet" days with at least 0.254 mm (0.01 in) of precipitation during the averaging period
W = average weight (tons) of vehicles traveling the road
k = particle size multiplier for particle size range and units of interest
sL = road surface silt loading (g/m^2)

	k
	g/VMT
PM2.5	0.25
PM10	1.00

Table 13.2.1-1
PARTICLE SIZE MULTIPLIERS FOR PAVED ROAD EQUATION

Fleet mix on highway

W= 9.1 tons, average
sL= 0.031 g/m2 Default value from URBEMIS 9.2 for Kern County
P= 36 days/year Buttonwillow Station 1940-2011, WRCC

E=
0.09836 g/VMT PM2.5
0.39344 g/VMT PM10

Vehicle weight (tons)		fraction of each vehicle type
1.6	passenger vehicles	0.75
40	large trucks	0.18
9	2-4 axle trucks	0.07

9.1 weighted average for all vehicles (ton)

On I-5 near the Project, 75% of all vehicles are passenger vehicles,
of the remaining vehicle, 73% are 5-axle trucks and the remainder are 2-4 axle trucks.
From information provided by California Department of Transportation for the traffic analysis.

Industrial Wind Erosion, AP-42 Section 13.2.5

Emission factor (g/m^2-yr) = k Σ P_i (from i=1,N) (Equation 2) 3/05/2013 revision

Erosion Potential (P_i) (g/m^2) = $58 (u^* - u_t^*)^2 + 25(u^* - u_t^*)$ (Equation 3)

0.5	k =	PM_{10} particle size multiplier
0.075	k =	$PM_{2.5}$ particle size multiplier
1	N =	number of disturbances per year
33.76	A =	exposed area of coal, m^2, per car (Table 4.1, Jan 2008 Connell Hatch: exposed area = 33.76 m^2)

Use Equation (1) to determine friction velocity:

$u(z) = u^* / 0.4 \times \ln(z/z_0)$

17.88	u(z) =	fastest mile (m/s) (based on speed of train)
0.2	z =	distance at which wind speed is measured (m) (based on the height above the coal cars at which wind flow would be laminar; assumed this height is equal to the difference between the height of the locomotive engine and the trailing coal cars)
0.003	z_0 =	roughness height for uncrusted coal pile (m), from Table 13.2.5-2
1.70	u^* =	friction velocity (m/s), solved for using Equation 1
0.55	u_t^* =	threshold friction velocity (m/s); Table 13.2.5-2 value for ground coal (surrounding coal pile)

Erosion Potential

	P =	105.9	g/m^2	erosion potential corresponding to the observed (or probable) fastest mile of wind for the i^{th} period between disturbances, g/m^2
Annual	A =	442,256.0	m^2/yr	exposed area of coal per car (m^2) times number of cars per year

Unmitigated Emissions

Emission factor (g/m^2-yr) = k Σ P_i (from i=1,N)

E =	23,423,432	grams PM_{10} / year
	25.82	tons PM_{10} / year
E =	3,513,515	grams $PM_{2.5}$ / year
	3.87	tons $PM_{2.5}$ / year

Mitigation Efficiency of Surfactant: **85%**

* HECA will be requiring the coal supplier to apply a surfactant to the coal transported by rail to reduce fugitive losses during transport. Surfactant achieves at least an 85% control efficiency.

Mitigated PM_{10}: **3.87 tons PM_{10} / year**

Mitigated $PM_{2.5}$: **0.58 tons $PM_{2.5}$ / year**

* It has been assumed that all emitted PM will be lost during the first 100 miles of the trip and has thus all been assigned to New Mexico. Maximum train speed (and thus wind speed) will certainly be reached within this time, and according to AP-42 Section 13.2.5.1, "particulate emission rates tend to decay rapidly (half-life of a few minutes) during an erosion event."

40	train speed, mph
0.447	m/s per 1 mph
453.6	grams per pound
2000	pounds per ton
13,100	Required rail car loads per year at normal operation (cars/yr)

Summary of Transportation Vehicles and Routes

3/05/2013 revision

Commodity Handled	Petcoke	Coal	Liquid Sulfur	Gasification Solids	Urea	UAN-32	Equipment Maintenance (1)	Miscellaneous Activities (2)
Expected plant operation								
Expected plant operation is 8000 hours / year								
The plant will operate 24 hours / day	24 hours / day	24 hours / day	24 hours / day	24 hours / day	24 hours / day	24 hours / day	24 hours / day	24 hours / day
The plant will operate 333 days / year	333 days / yr	333 days / yr	333 days / yr	333 days / yr	333 days / yr	333 days / yr	333 days / yr	333 days / yr
Shipment by trucks	100 %	100 %	100 %	100 %	100 %	100 %	100 %	100 %
Shipment by train	0 %	100 %	0 %	0 %	0 %	0 %	0 %	0 %
Production rate								
Required Normal Flow / day	1,140 tons / day	4,580 tons / day	100 tons / day	950 tons / day	1,720 tons / day	1,400 tons / day		
Required Normal Flow / year	380,000 tons / yr	1,526,000 tons / yr	34,000 tons / yr	317,000 tons / yr	573,000 tons / yr	467,000 tons / yr		
Required Maximum Flow day	2,000 tons / day (3)	6,500 tons / day (4)	200 tons / day (5)	1,900 tons / day (6)	3,440 tons / day (6)	2,800 tons / day (6)		
Truck Shipments								
Truck Capacity	25 tons / truck	25 tons / truck	25 tons / truck	25 tons / truck	25 tons / truck	25 tons / truck	25 tons / truck	25 tons / truck
Required trucks loads for normal operation / day	46 trucks / day	184 trucks / day	4 trucks / day	38 trucks / day	69 trucks / day	56 trucks / day	3 trucks / day	11 trucks / day
Required trucks loads for normal operation / yr	15,200 truck / yr	61,040 truck / yr	1,360 truck / yr	12,680 truck / yr	22,920 truck / yr	18,680 truck / yr	1,000 truck / yr	3,690 truck / yr
Required trucks loads for maximum operation /day	80 trucks / day	260 trucks / day	8 trucks / day	76 trucks / day	138 trucks / day	112 trucks / day	5 trucks / day	17 trucks / day
Train Shipments								
Railcar Capacity		117 tons / car	100 tons / car	100 tons / car	100 tons / car	100 tons / car		
Required railcars for normal operation / day		40 cars / day	0 cars / day	0 cars / day	0 cars / day	0 cars / day		
Required railcar loads for normal operation / yr		13,100 cars / yr	0 cars / yr	0 cars / yr	0 cars / yr	0 cars / yr		
Required railcars for maximum operation / day		200 cars / day	0 cars / day	0 cars / day	0 cars / day	0 cars / day		
Basis	- 91% availability	- 91% availability	- 91% availability	- 91% availability	- 91% availability	- 91% availability		
	- 25% petcoke (heat input) per year	- 75% coal (heat input) per year	- High sulfur case - 100 tons/day	- 75% coal max annual average				
	- 25 ton/truck	- 117 tons/car	- 25 ton/truck		-empty 45 day storage in 10 days	-empty 45 day storage in 10 days		
	- 7 days/week receiving	- 100% coal for maximum	- Weekdays only		10 days	10 days		
	- 25% excess truck movement capacity	- Rack sized to handle two trains/day		- Maximum is double the daily average rate				
Traffic route	Truck Route	Truck Route	Truck Route	Truck Route	Truck Route	Truck Route	Truck Route	Truck Route
Destination/Origin	Carson Refinery	Wasco rail terminal to site	California Sulfur	Various	Various	Various	Various	Various
Address	1801 E Sepulveda, Carson		2509 E Grant Street, Wilmington					
Distance	140 miles	26.5 miles	142 miles	80 mile radius	40 mile radius	40 mile radius	40 mile ratius	40 mile ratius
Route	Alameda 405 Fwy 5 Fwy Stockdale hwy Morris Road Station Road		Grant Henry Ford Alameda 405 Fwy 5 Fwy Stockdale hwy Morris Road Station Road	40 mile radius Station Road Morris Road Stockdale Hywy 5 Fwy	Station Road Morris Road Stockdale Hywy 5 Fwy	Station Road Morris Road Stockdale Hywy 5 Fwy	5 fwy Stockdale Hwy Dairy Road	5 fwy Stockdale Hwy Dairy Road
	Rail Route	Rail Route	Rail Route	Rail Route	Rail Route	Rail Route	Rail Route	Rail Route
Destination/Origin	None	Elk Ranch New Mexico	None	None	None	None	None	None
Address								
Distance		801 miles						
Route		Kern County: 139.2 miles (County Line near Boron, CA to north property line of plant) Mine to Boron, CA: 662 miles Total Distance: 801.2 miles						

Notes
1) Equipment Maintenance Trucks are considered to be 2% of the total trucks per day for the feed and product operation.
2) Miscellaneous trucks are considered to be 3% of the total trucks per day for the feed and product operation.
3) The maximum flow rate of coke is ratioed up from the normal flow rate at 25% to 30% of feed
4) The maximum flow rate of coal is ratioed up from the normal flow rate at 75% to 100% of feed
5) The maximum flow rate of sulfur is 2 times the normal production
6) The maximum flow rate of these commodities is 2 times the normal production
7) The sources of flow data used in the Production Rate calculation were based on the flow rates provided in "Conference Note: Rail and Truck Traffic - Planning Session" and the "FertilizerProductMovement Update", 01-25-12.

Calculations for Trucks Operation onsite

Data Supplied By Client					
Parameter	**Petcoke and Coal Trucks**		**Product Trucks**		**Miscellaneous Trucks**
	Running Emissions	**Idling Emissions**	**Running Emissions**	**Idling Emissions**	**Running Emissions**
Distance Traveled (mi)*	0.96		2.49		2.20
Per Truck Idle Time (hr)		0.083		0.083	
Maximum number of trucks or loads:					
Annual average trucks or loads	76,240	76,240	55,640	55,640	4,662

EMFAC2007 Emission Factors + Fugitive Dust (g/mi or g/idle-hour) For Truck Model year 2010

	Coke and Coal Trucks		**Product Trucks**		**Miscellaneous Trucks**
Pollutant	**Running Emissions (g/mile/trk)**	**Idling Emissions (g/idle-hour/trk)**	**Running Emissions (g/mile/trk)**	**Idling Emissions (g/idle-hour/trk)**	**Running Emissions (g/mile/trk)**
CO	3.03	43.69	3.03	43.69	3.03
NOx	5.43	122.65	5.43	122.65	5.43
ROG	1.39	7.74	1.39	7.74	1.39
SOx	0.03	0.06	0.03	0.06	0.03
PM10 *	0.92	0.11	0.92	0.11	0.92
PM2.5 *	0.29	0.10	0.29	0.10	0.29

EMFAC2007 is the approved federal model for vehicle combustion emissions
* PM10 and PM2.5 includes fugitive dust factor for paved roads obtained from AP-42 Ch. 13 plus PM factors from EMFAC 2007
PM factors from EMFAC = combustion exhaust + tire wear + break wear
EMFAC emissions are for fleet year 2010 travelling at 10 mph.

Annual Emission Rates in g/s For All Trucks

	Coke and Coal Trucks		**Product Trucks**		**Miscellaneous Trucks**		
Pollutant	**Running Emissions**	**Idling Emissions (at each Idle Point)**	**Running Emissions**	**Idling Emissions (at each Idle Point)**	**Running Emissions**	**TOTAL (g/s)**	**TOTAL (tpy)**
CO	7.000E-03	8.802E-03	1.328E-02	6.423E-03	9.846E-04	3.65E-02	1.27E+00
NOx	1.255E-02	2.471E-02	2.380E-02	1.803E-02	1.765E-03	8.09E-02	2.81E+00
ROG	3.209E-03	1.560E-03	6.087E-03	1.139E-03	4.513E-04	1.24E-02	4.33E-01
SOx	6.936E-05	1.249E-05	1.316E-04	9.116E-06	9.755E-06	2.32E-04	8.07E-03
PM10	2.120E-03	2.297E-05	4.021E-03	1.676E-05	2.982E-04	6.48E-03	2.25E-01
PM2.5	6.762E-04	2.095E-05	1.283E-03	1.529E-05	9.511E-05	2.09E-03	7.27E-02

Volume, Line Sources

Guidance for Air Dispersion Modeling, SJVAPCD, 2007 and Section 1.2.2 of Volume II of ISC User's Guide			
2.3.2 Oyo=12W/2.15			
Truck Traveling vol src		Truck Idling pt src	
6	ft Release height	12.6	ft Release height
12	ft Width	0.1	m diam
66.98	ft init horz dim Syo	51.71	m/s vel
5.58	ft init vert dim Szo	366	K Temp
		199.134	F Temp

Volume, Stand Alone

Guidance for Air Dispersion Modeling, SJVAPCD, 2007	
2.3.2 + modelers judgement + ISC guidance	
Truck Traveling vol src	
6	ft Release height
12	ft Width
2.79	ft init horz dim Syo
5.58	ft init vert dim Szo

3/05/2013 revision

Transportation Information			Notes
- Onsite Vehicle =	20	trucks	- Information Provided By Applicant
- Vehicle year=	2010		- Information Provided By Applicant
- Maximum annual mileage =	10,000	miles/truck-year	- All routine vehicular traffic is anticipated to travel exclusively on paved roads
			- Assumed 15 mph average speed within HECA facility

EMFAC2007 Emission Factors (g/mi) For Truck Model year 2010

	Emission Factors in g/mi	
Pollutant	**Gas LHDT1**	**Diesel LHDT2**
CO	0.229	0.920
NOx	0.064	0.672
ROG	0.014	0.085
SOx	0.011	0.005
PM10 *	0.167	0.176
PM2.5 *	0.054	0.062

EMFAC2007 is the approved federal model for vehicle combustion emissions
* PM10 and PM2.5 includes fugitive dust factor for paved roads obtained from AP-42 Ch. 13 plus PM factors from EMFAC 2007
PM factors from EMFAC = combustion exhaust + tire wear + break wear
EMFAC emissions are for fleet year 2010 travelling at 15 mph.

Annual Emission Rates in g/s From All Trucks

	Emissions in g/s			
Pollutant	**Gas LHDT1**	**Diesel LHDT2**	**TOTAL (g/s)**	**TOTAL (tpy)**
CO	1.45E-03	5.83E-03	7.29E-03	0.253
NOx	4.06E-04	4.26E-03	4.67E-03	0.162
ROG	8.88E-05	5.39E-04	6.28E-04	0.022
SOx	6.98E-05	3.17E-05	1.01E-04	0.004
PM10	1.06E-03	1.11E-03	2.17E-03	0.076
PM2.5	3.40E-04	3.91E-04	7.32E-04	0.025

Fugitive Dust on Paved Road

3/05/2013 revision

AP 42 13.2.1 Paved Roads, updated January 2011

For a daily basis,
E = [k (sL)^0.91 x (W)^1.02](1-P/4N) (2)

P = number of "wet" days with at least 0.254 mm (0.01 in) of precipitation during the averaging period
W = average weight (tons) of vehicles traveling the road
k = particle size multiplier for particle size range and units of interest
sL = road surface silt loading (g/m^2)

	k
	g/VMT
PM2.5	0.25
PM10	1.00

Table 13.2.1-1
PARTICLE SIZE MULTIPLIERS FOR PAVED ROAD EQUATION

Large Trucks

				Empty truck	full truck	Load Capacity
W=	17.5	tons, average		5	30	0 tons
sL=	0.031	g/m2	Default value from URBEMIS 9.2 for Kern County			
P=	36	days/year Buttonwillow Station 1940-2011, WRCC				

E=
0.19149 g/VMT PM2.5 large delivery trucks
0.76594 g/VMT PM10 large delivery trucks

Operation and Maintenance Vehicles

W=	3	tons	
sL=	0.031	g/m2	Default value from URBEMIS 9.2 for Kern County
P=	36	days/year Buttonwillow Station 1940-2011, WRCC	

E=
0.03169 g/VMT PM2.5 large delivery trucks
0.12675 g/VMT PM10 large delivery trucks

APPENDIX D

MITIGATION AGREEMENT

MITIGATION AGREEMENT 20130092

This Mitigation Agreement ("Agreement") is entered into as of April 18, 2013 by and between Hydrogen Energy California LLC ("Developer") and the SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT ("District"), an air pollution control district formed pursuant to California Health and Safety Code section 40150, et seq.

RECITALS

WHEREAS, District is an air pollution control district formed by the counties of Fresno, Kern, Kings, Madera, Merced, San Joaquin, Stanislaus and Tulare, pursuant to California Health and Safety Code section 40150, et seq.; and

WHEREAS, District is responsible for developing and implementing air quality control measures within the District Boundaries, including air quality control measures for stationary sources, and indirect sources; and

WHEREAS, Developer submitted an Amended Application for Certification (08-AFC-8A) seeking licensing from the California Energy Commission (CEC) which will permit the development of a Project located in the County of Kern, California, as more particularly described on Exhibit A attached hereto and incorporated herein (the "Project"); and

WHEREAS, the Project will cause impacts on air quality within the geographical boundaries of the San Joaquin Valley Unified Air Pollution Control District, as depicted on Exhibit B attached hereto and incorporated herein (the "District Boundaries"); and

WHEREAS, the term "indirect" emissions as used in this Agreement refers to emissions from construction and transportation activities, as opposed to emissions from permitted stationary sources; and

WHEREAS, as a result of funding provided to the Project by the U.S. Department of Energy ("DOE"), the Project is subject to District Rule 9110 and Clean Air Act Section 176(c)(1) as implemented by 40 CFR Part 93 Subpart B, "Determining Conformity of Federal Actions to State or Federal Implementation Plans" (General

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Conformity); and

WHEREAS, Developer has prepared, and District staff has reviewed and concurred in, a General Conformity Evaluation for the Project, including air quality impact modeling for assessing indirect air quality emission impacts associated with construction and operation of the Project; and

WHEREAS, the General Conformity Evaluation demonstrates indirect emissions are expected to exceed the following Conformity Thresholds in the San Joaquin Valley Air Basin: 10 tons/year NOx, and 10 tons/year ROG/VOC; and

WHEREAS, District has determined that Developer's payment of fees into District's Emission Reduction Incentive Program (ERIP) will provide pound-for-pound offsets of Project indirect emissions that exceed the General Conformity thresholds and result in DOE's federal action conforming to the applicable state implementation plan (SIP), all as set forth in the General Conformity Evaluation for the Project; and

WHEREAS, the emission offsets that will be provided pursuant to this Agreement for purposes of satisfying the General Conformity requirements are distinct from and in addition to any new source review emission offsets that Developer is required to provide pursuant to District Rule 2201; and

WHEREAS, the Project is subject to review pursuant to the California Environmental Quality Act ("CEQA") codified at California Public Resources Code Section 21000, et seq.; and

WHEREAS, pursuant to its certified regulatory program, the CEC acts as CEQA lead agency for the Project and the District is a CEQA responsible agency for the Project; and

WHEREAS, District has determined, in its role as a CEQA responsible agency, that Project indirect emissions are expected to exceed the District CEQA Significance Thresholds of 10 tons/year NOx, 10 tons/year ROG/VOC and 15 tons/year PM10 and that additional mitigation measures beyond those proposed by Developer are necessary to mitigate Project indirect emissions below a level of significance; and

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WHEREAS, District has determined that Developer's payment of fees into District's Emission Reduction Incentive Program (ERIP) will further mitigate Project indirect emissions that exceed the District CEQA Significance Thresholds and result in Project indirect emissions being mitigated below the level of significance; and

WHEREAS, District has determined that with appropriate funding, District can provide additional reductions of emissions from certain projects in types and in sufficient quantities which, when combined with other measures proposed by Developer, will offset and mitigate Project criteria pollutant emissions for construction and operation , such that the Project will not result in significant impacts to air quality and the DOE action with respect to the Project will conform to the applicable SIP; and

WHEREAS, Developer and District desire to enter into this Agreement in order to develop and implement air quality control measures which, when combined with other measures proposed by Developer, will offset and mitigate the emissions for the Project, so that the development of such Project will not result in an increase in criteria pollutant emissions over those which would otherwise exist without the development thereof; and

WHEREAS, District has determined that compliance with the terms of this Agreement will ensure that the Project will have no significant adverse impacts to air quality, and that DOE's action with respect to the Project will conform to the applicable SIP as more fully set forth in the General Conformity Evaluation prepared for the Project.

AGREEMENT

NOW, THEREFORE, in exchange of the mutual covenants herein contained, Developer and District hereby agree as follows:

1. **Offsetting and Mitigation of Project Related Impacts on Air Quality**

Project related indirect emissions from construction and operation that exceed applicable CEQA and General Conformity thresholds shall be offset and mitigated by achieving real, surplus, quantifiable and enforceable reductions of ROG/VOC, NOx,

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and PM_{10} through implementation of Emission Reduction Measures in accordance with this Agreement. The determination of whether proposed emission reductions are real, surplus, quantifiable and enforceable shall be performed by the District through its Strategy and Incentives Department. Estimated Project related indirect source emissions that exceed applicable CEQA and General Conformity thresholds are set forth in Exhibit C, which is attached hereto and incorporated herein, and shall be offset and mitigated as demonstrated in Exhibit C. For construction emission impacts, indirect emissions of any criteria pollutant exceeding the applicable General Conformity Threshold or District CEQA Significance Threshold in any given year will be fully offset and mitigated for that pollutant for the entire project construction period. For operational emission impacts, indirect emissions of any criteria pollutant exceeding the applicable General Conformity Threshold or District CEQA Significance Threshold will be fully offset and mitigated for that pollutant, as specified in Exhibit C.

2. **Payment of Air Quality Mitigation Fees**

No later than five months prior to breaking ground for construction of the Project, Developer shall pay Air Quality Mitigation Fees to District in the amount of three million three hundred twenty seven thousand three hundred thirty four dollars ($3,327,334) for implementation of Emission Reduction Measures to offset and mitigate Project construction emissions as specified in Exhibit C. The amount specified above includes a 4% administration fee to cover the District's costs of administering this Agreement.

No later than six months prior to the commercial operation date (COD) for the Project, Developer shall pay additional Air Quality Mitigation Fees to the District in the amount of four million two hundred thirty eight thousand six hundred ninety two dollars ($4,238,692) for implementation of Emission Reduction Measures to offset and mitigate Project indirect operational emissions as specified in Exhibit C. The amount specified above includes a 4% administration fee to cover the District's costs of administering this Agreement.

///

3. **Implementation of Emission Reduction Measures**

Upon Developer's submission to District of the Air Quality Mitigation Fees specified in paragraph 2 above, District shall (1) use diligent efforts to enter into Funding Agreements with owners and/or operators of pollution source equipment to implement the Emission Reduction Proposals within 150 days (in the case of Emission Reduction Measures to offset and mitigate construction emissions) and 180 days (in the case of Emission Reduction Measures to offset and mitigate indirect operational emissions); (2) determine the types and quantities of permanent reduction in emissions which would be realized by the Emission Reduction Measures; (3) perform the determination of surplus emission reductions of ROG/VOC, NOx, and PM10; and (4) advise Developer of such determinations in writing.

District shall notify Developer or designee in writing of Funding Agreements entered into by the District. In the event District is unable to achieve the required reductions District shall provide Developer a written statement of the amount of reductions that have been achieved. Developer shall have a reasonable time, not to exceed ninety (90) days, within which to submit to District additional Emission Reduction Proposal(s) or provide District additional Air Quality Mitigation Fees.

4. **Refunds**

Upon verification by District that Project indirect emissions have been fully offset and mitigated in accordance with this Agreement, District shall refund Developer any unused Air Quality Mitigation Fees. District shall have reasonable time, not to exceed sixty (60) days, to refund Developer.

5. **CEQA & General Conformity Compliance**

District hereby confirms that with implementation of this Agreement: i) Project construction emissions of any criteria pollutant exceeding the General Conformity Threshold or District CEQA Significance Threshold in any given year will be fully offset and mitigated for that pollutant for the entire project construction period; and ii) Project indirect operational emissions of any criteria pollutant exceeding the General

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Conformity Threshold or District CEQA Significance Threshold will be fully offset and mitigated for that pollutant.

6. **District's Obligations**

6.1 **Acknowledgement Regarding Full Offset and Mitigation**

Upon successful implementation of the Emission Reduction Measures pursuant to Paragraph 3, District shall verify in writing to Developer, the CEC and the DOE that the Project related impacts on air quality have been fully offset and mitigated as set forth in Paragraph 5. For the purpose of this Agreement, fully offset and mitigated means that the reductions specified in Exhibit C have been achieved.

6.2 **Oversight of Funding Agreements**

District shall ensure that the owners/operators of equipment subject to Funding Agreements perform all obligations to be performed on the part of such parties under said Funding Agreements.

6.3 **Oversight of Air Quality Mitigation Monitoring Plan**

Upon request of the CEC, District shall oversee that portion of the mitigation monitoring plan adopted by CEC which relates to the mitigation brought about by this Agreement. Alternatively, upon request of the CEC, District shall cooperate with the CEC in the oversight of that portion of the mitigation monitoring plan adopted by the CEC for the Project which relates to the mitigation brought about by this Agreement.

6.4 **Documentation, Record Keeping and Monitoring**

District shall document, keep adequate records on and monitor the emission reductions brought about as a result of this Agreement, and shall, upon written request by Developer, the CEC or the DOE, provide Developer, the CEC or the DOE written reports verifying achieved emission reductions and/or emission reductions being brought about to fully offset and mitigate Project related impacts on air quality.

6.5 **Achievement of Emission Reductions**

For and in exchange of Developer's payment of funds pursuant to Paragraph 2 above, District shall ensure, by way of entering into, funding and enforcing the Funding

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Agreements in accordance with the provisions of this Agreement, that the Project achieves the required emission reductions to the extent specified in this Agreement. District shall ensure that implementation of Emission Reduction Measures to offset Project indirect operational emissions as specified in Exhibit C shall result in emission reductions in a timeframe complying with the general conformity mitigation requirements of 40 CFR 93.163.

7. **Subsequent Litigation, Legislation and/or Administrative Action / Credit to Developer**

In the event that despite this Agreement, Developer is required as a result of a final judgment or District Approved Settlement (as defined below) in any subsequent third party litigation, to pay monies in addition to the monies to be paid by Developer pursuant to Paragraph 2 above, then District shall acknowledge and credit Developer with the emission reductions achieved pursuant to this Agreement and any additional emission reductions achieved to mitigate the Project related impacts on air quality that will result from Developer's payment of such additional monies. To the extent that monies paid by Developer pursuant to Paragraph 2 above, when combined with monies paid pursuant to a District Approved Settlement, result in emission reductions in excess of those required to fully offset and mitigate Project related emissions as required by this Agreement, District shall refund to Developer any remaining Air Quality Mitigation Fees in excess of those required to achieve the emission reductions contemplated by this Agreement. For purposes of this Paragraph, a "District Approved Settlement" shall mean a settlement of a lawsuit filed pursuant to CEQA, the National Environmental Protection Act or other applicable environmental law which (i) provides for Developer's payment of monies in exchange for a dismissal or settlement of such lawsuit, (ii) provides for the use of such monies by the petitioner in such lawsuit in such a manner as to mitigate adverse air quality impacts of the Project, and (iii) is approved in writing by District.

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8. **Term of Agreement**

This Agreement shall be effective upon the date first written above, and shall terminate upon District's meeting its obligation to implement Emission Reduction Measures that provide necessary emissions reductions to fully offset and mitigate the indirect Project related air impacts, including any associated monitoring, recordkeeping and reporting. Developer may, at any time by written notice to District, terminate this Agreement, whereupon, (i) District shall acknowledge in writing to the CEC and DOE that Developer has offset and mitigated indirect air quality impacts of the Project to the extent and in the types and quantities brought about by Funding Agreements and Emission Reduction Measures implemented as of the date of termination, (ii) District shall refund to Developer any unused portion of Developer's Air Quality Mitigation Fees less any unpaid administrative fees incurred; and (iii) neither Developer nor District shall have any further rights or obligations under this Agreement except as expressly provided. District's obligations to oversee implementation of Funding Agreements pursuant to Paragraph 9 and to ensure that required emission reductions are achieved, pursuant to Paragraph 9, shall remain effective for as long as necessary to ensure that the anticipated emission reductions continue to be achieved to the extent specified in this Agreement.

9. **Representations, Covenants and Warranties**

9.1. **Developer's Representations, Covenants and Warranties**.

Developer represents, covenants and warrants to District, as of the date of this Agreement, as follows:

9.1.1. The undersigned representatives of Developer are duly authorized to execute, deliver and perform this Agreement, and upon Developer's execution and delivery of this Agreement, this Agreement will have been duly authorized by Developer.

9.1.2. Upon execution and delivery of this Agreement by Developer, Developer's obligations under this Agreement shall be legal, valid and binding obligations of Developer, duly enforceable at law and in equity in accordance with the terms and conditions of this Agreement.

9.1.3. There is no lawsuit, legal action, arbitration, legal or administrative proceeding, legislative or quasi-legislative action or claim existing, pending, threatened or anticipated which would render all or any portion of this Agreement invalid, void or unenforceable in accordance with the terms and conditions thereof.

9.1.4. Other than the execution and delivery of this Agreement by the undersigned representatives of Developer, there are no approvals, consents, confirmations, proceedings, or other actions required by Developer or any third party, entity or agency in order to enter into and carry out the terms, conditions and intent of the parties with respect to this Agreement.

9.2. **District's Representations, Covenants and Warranties**

District represents, covenants and warrants to Developer, as of the date of this Agreement, as follows:

9.2.1. The undersigned representatives of District are duly authorized to execute, deliver and perform this Agreement, and upon District's execution and delivery of this Agreement, this Agreement will have been duly authorized by District.

9.2.2. Upon execution and delivery of this Agreement by District, District's obligations under this Agreement shall be legal, valid and binding obligations of District, duly enforceable at law and in equity in accordance with the terms and conditions of this Agreement.

9.2.3. There is no lawsuit, legal action, arbitration, legal or administrative proceeding, legislative, quasi-legislative or administrative action or claim existing, pending, threatened or anticipated which would render all or any portion of this Agreement invalid, void or unenforceable in accordance with the terms and conditions thereof.

9.2.4. Other than the execution and delivery of this Agreement by the undersigned representatives of District, there are no approvals, consents,

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confirmations, proceedings, or other actions required by District or any third party, entity or agency in order to enter into and carry out the terms, conditions and intent of the parties with respect to this Agreement.

9.2.5. The monies paid by Developer under this Agreement shall be sufficient to ensure that the emission reduction contemplated by this Agreement shall occur, and District shall utilize such monies in such a manner as to ensure that such emission reduction shall occur.

9.2.6. Upon the approval of this Agreement by the governing board of District, the Air Pollution Control Officer of District, or equivalent representative, or a delegee of such officer, shall have the authority to approve, deliver, verify, enter into, acknowledge and/or accept any communication, notice, notification, verification, agreement and/or other document to be issued or entered into by District under the terms and conditions of this Agreement, without further approval of the governing board of District.

10. **Indemnification**

Developer agrees to indemnify, defend and hold harmless District for, from and in connection with any third party claims, losses and/or liabilities arising from or in connection with District's performance of this Agreement, excluding only such claims, losses and/or liabilities which result from or in connection with District's sole negligence, act or omission.

11. **Inurement**

Developer's rights and obligations under this Agreement, or applicable portions thereof, shall inure to the benefit of and be binding upon the heirs, successors and assigns of Developer. Upon Developer's conveyance of all or any portion of the Project, the rights and obligations of Developer under this Agreement shall, to the extent applicable, be transferred to the transferee thereof, and Developer shall thereupon be released by District from, all obligations and liabilities so assigned, except for such obligations and liabilities arising prior to such transfer.

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12. **Assignment**

Developer shall have the right to assign all or any part of its rights and/or obligations under this Agreement. Upon any such assignment, Developer shall deliver to District a written assignment and assumption agreement specifying the fact and extent of the assignment, the name and address of the assignee, and the assignee's assumption of all obligations of Developer thereby assigned. Developer shall have the right to assign all or any part of its rights and/or obligations under this Agreement to a third party for use in connection with the mitigation of air quality impacts resulting from one or more projects other than the Project, so long as (i) the project is located within the District Boundaries, (ii) the air quality impacts of such project(s) will in fact be mitigated, as verified by District, by the emission reductions brought about by this Agreement, and (iii) the project(s) consist of residential, commercial, industrial and/or mixed use real estate projects. Upon any such assignment by Developer, District shall enter into an amendment of this Agreement which acknowledges the assignment and conforms the various provisions of this Agreement as may be required to be conformed in order to provide to the assignee the rights and benefits of this Agreement as if such assignee and its project were the original party and project contemplated in this Agreement.

13. **Recitals Incorporated**

The recitals set forth hereinabove are hereby incorporated into this Agreement and acknowledged, agreed to and adopted by the parties to this Agreement.

14. **Further Assurances**

Developer and District agree to execute and deliver any documents and/or perform any acts which are reasonably necessary in order to carry out the intent of the parties with respect to this Agreement.

15. **No Joint Venture or Partnership**

District and Developer agree that nothing contained in this Agreement or in any document executed in connection with this Agreement shall be construed as making

District and Developer joint venturers or partners.

16. **Notices**

Any notices or communications relating to this Agreement shall be given in writing and shall be deemed sufficiently given and served for all purposes when delivered, if (a) in person, (b) by facsimile (with the original delivered by other means set forth in this paragraph, (c) by generally recognized overnight courier or (d) by United States Mail, certified or registered mail, return receipt requested, postage prepaid, to the respective addresses set forth below, or to such other addresses as the parties may designate from time to time by providing written notice of the change to the other party.

DEVELOPER	**DISTRICT**
Hydrogen Energy California, LLC 30 Monument Square, Suite 235 Concord, MA 01742 Fax: (978)287-9529 Attn: Marisa Mascaro	Seyed Sadredin Executive Director/APCO 1990 E. Gettysburg Avenue Fresno, CA 93726 (559) 230-6000 Fax: (559) 230-6061

17. **Entire Agreement**

The terms of this Agreement, together with all attached exhibits, are intended by the parties as the complete and final expression of their agreement with respect to such terms and exhibits and may not be contradicted by evidence of any prior or contemporaneous agreement. This Agreement specifically supersedes any prior written or oral agreements between the parties with respect to the subject matter of this Agreement.

18. **Amendments and Waivers**

No addition to or modification of this Agreement shall be effective unless set forth in writing and signed by the party against whom the addition or modification is sought to be enforced. The party benefited by any condition or obligation may waive the same, but such waiver shall not be enforceable by another party unless made in writing and signed by the waiving party.

19. **Invalidity of Provisions**

If any provision of this Agreement as applied to either party or to any circumstance shall be adjudged by a court of competent jurisdiction to be void or unenforceable for any reason, the same shall in no way affect (to the maximum extent permissible by law) any other provision of this Agreement, the application of any such provision under circumstances different from those adjudicated by the court, or the validity or enforceability of this Agreement as a whole. The parties further agree to replace any such invalid, illegal or unenforceable portion with a valid and enforceable provision, which will achieve, to the maximum extent legally possible, the economic, business or other purposes of the invalid, illegal or unenforceable portion.

20. **Construction**

Unless otherwise indicated, all paragraph references are to the paragraph of this Agreement and all references to days are to calendar days. Whenever, under the terms of this Agreement the time for performance of a covenant or condition falls upon a Saturday, Sunday or California state holiday, the time for performance shall be extended to the next business day. The headings used in this Agreement are provided for convenience only and this Agreement shall be interpreted without reference to any headings. Wherever required by the context, the singular shall include the plural and vice versa, and the masculine gender shall include the feminine or neuter genders, or vice versa. This Agreement may be executed in one or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. The language in all parts of this Agreement shall be construed as a whole in accordance with its fair meaning, and shall not be construed against any party solely by virtue of the fact that such party or its counsel was primarily responsible for its preparation.

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21. **Governing Law**

This Agreement shall be governed by the laws of the State of California applicable to contracts made and to be performed in California.

22. **No Third-party Beneficiaries**

Nothing in this Agreement, express or implied, is intended to confer any rights or remedies under or by reason of this Agreement on any person other than the parties to it and their respective permitted successors and assigns, nor is anything in this Agreement intended to relieve or discharge any obligation of any third person to any party hereto or give any third person any right of subrogation or action over or against any party to this Agreement.

23. **Exhibits**

The exhibits attached to this Agreement shall be deemed to be a part of this Agreement and are fully incorporated herein by reference.

24. **Force Majeure**

The time within which any party shall be required to perform under this Agreement shall be extended on a day-per-day basis for each day during which such performance is prevented or delayed by reason of events reasonably outside of the control of the performing party, including, without limitation, acts of God, events of destruction, acts of war, civil insurrection, strikes, shortages, governmental delays, moratoria, civil litigation and the like, and/or delays caused by the non-performing party's act or omission.

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IN WITNESS WHEREOF, Developer and District have executed this Agreement and agree that it shall be effective as of the date first written above.

DEVELOPER

Hydrogen Energy California LLC

____
James L. Croyle
Chief Executive Officer

DISTRICT

San Joaquin Valley Unified Air Pollution Control District

____
Skip Barwick
Governing Board Chair

Recommended for approval:
San Joaquin Valley Unified Air Pollution Control District

____
Seyed Sadredin
Executive Director/APCO

Approved as to legal form:
San Joaquin Valley Unified Air Pollution Control District

____
Catherine Redmond
District Counsel

Approved as to accounting form:

____
Cindi Hamm
Director of Administrative Services

For accounting use only:
San Joaquin Valley Unified Air Pollution Control District

Program: ______________
Account No: ______________

EXHIBIT A

DESCRIPTION OF THE PROJECT

The HECA IGCC polygeneration project is located near the community of Tupman, as shown in Figure 1. The Project will gasify a fuel blend of 75 percent coal and 25 percent petroleum coke (petcoke) to produce synthesis gas (syngas). Syngas produced via gasification will be purified to hydrogen-rich fuel, and used to generate a nominal 300 megawatts (MW) of low-carbon baseload electricity in a Combined Cycle Power Block, low-carbon nitrogen-based fertilizer in an integrated Manufacturing Complex, and carbon dioxide (CO_2) for use in enhanced oil recovery (EOR). The HECA Project Site comprises a 453-acre parcel of land on which the HECA IGCC electrical generation facility, low-carbon nitrogen-based fertilizer Manufacturing Complex, and associated equipment and processes (excluding off-site portions of linear facilities), will be located. HECA has an agreement to purchase the HECA Project Site, as well as an additional 653 acres adjacent to the HECA Project Site, herein referred to as the Controlled Area. HECA will have control over public access and future land use on this property. In addition, the HECA Project will include the following linear facilities, which extend off the Project Site.

- Electrical transmission line. An approximately 2-mile-long electrical transmission line will interconnect the Project to a future Pacific Gas and Electric Company (PG&E) switching station east of the Project Site.

- Natural gas supply pipeline. An approximately 13-mile-long natural gas interconnection will be made with PG&E natural gas pipelines north of the Project Site.

- Water supply pipelines and wells. An approximately 15-mile-long process water supply line and up to five new groundwater wells will be installed by the Buena Vista Water Storage District (BVWSD) to supply brackish groundwater from northwest of the Project Site. An approximately 1-mile-long water supply linear from the West Kern Water District (WKWD) east of the Project Site will provide potable water.

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EXHIBIT B

DISTRICT BOUNDARIES

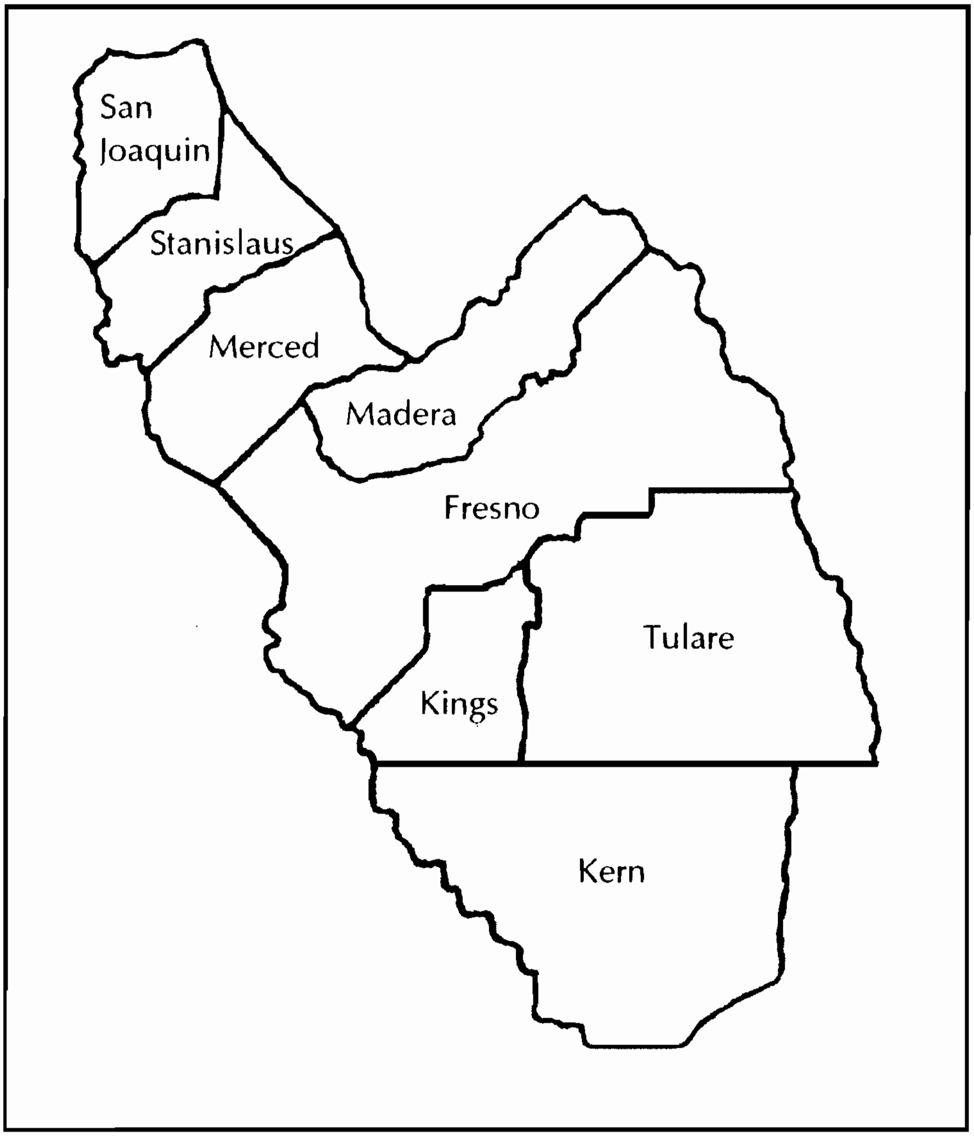

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EXHIBIT C

PROJECT EMISSION MITIGATION FEES

HECA	ALT 1 - TRAIN			ALT 2 - TRUCKS		
	NOx	PM_{10}	VOC	NOx	PM_{10}	VOC
2013 Construction	50.1	25.9	5.5	50.1	25.9	5.5
2014 Construction	69.0	15.4	11.9	69.0	15.4	11.9
2015 Construction	68.6	10.5	12.4	68.6	10.5	12.4
2016 Construction	45.8	8.1	8.4	45.8	8.1	8.4
2017 Construction	10.1	1.4	1.3	10.1	1.4	1.3
2017 Operation	13.3	1.4	0.6	14.5	2.9	1.1
2018 Operation and beyond	39.9	4.2	1.9	43.6	8.6	3.2
District CEQA Thresholds	10	100	10	10	100	10
Conformity Threshold	10	15	10	10	15	10

Notes: This agreement provides mitigation for all shaded values:

~ The highest emitting alternative scenario for operations and construction is the alternative in which all deliveries and shipments are made by truck (ALT 2)

~ All construction emissions (NOx, PM_{10} and VOC) are mitigated

~ All operational indirect source NOx emissions are mitigated at the maximum single year value of 43.6 tons per year. Operational PM_{10} and VOC emissions do not exceed the District's significance thresholds.

	Per Year
NOx and VOC $/ton (ISR)	$ 9,350
PM10 $/ton (ISR)	$ 9,011

Mitigation

Construction:	344.4	tons, total (NOx+VOC+PM10)
	$ 3,327,334	
Operation:	43.6	tons/yr (NOx), max year
	$ 4,238,692	
Total Mitigation Amount:	$ 7,566,025	Includes a 4% administration fee

BIOLOGICAL RESOURCES

Amy Golden

SUMMARY OF CONCLUSIONS

Hydrogen Energy California, LLC (applicant) is proposing to build Hydrogen Energy California (HECA or project), an Integrated Gasification Combined Cycle (IGCC) power generating facility, on 544 acres of actively farmed agricultural lands in western Kern County, including 453 acres for the IGCC facility and 91 acres for temporary staging (**Biological Resources Table 2**). An additional 229 acres of agricultural and disturbed natural lands would be developed for five linear routes including four buried pipelines, an above ground transmission line and PG&E electrical switchyard, and optional railroad spur.

Construction of the project would primarily impact agricultural lands and intermixed non-native grassland, allscale scrub habitats that provide habitat for a number of upland species covered under the U.S. Fish and Wildlife Service's *Recovery Plan for Upland Species of the San Joaquin Valley* (Recovery Plan, USFWS 1998). HECA would impact approximately 33 acres of allscale scrub habitat, which would mostly occur along the carbon dioxide pipeline route. The proposed carbon dioxide pipeline route located on the lower flanks of the Elk Hills Oil Field and immediately north of the Elk Hills mitigation parcels, is the linear route that supports the most contiguous natural, non-farmland type of habitat in the project area and staff believes this linear route represents the highest quality natural habitat and poses the highest threat for construction impacts to upland species (**Biological Resources Figure 2**). In addition, five sites along the natural gas pipeline route also support areas of disturbed allscale scrub and some of these sites represent similar habitat values as the nearby Buttonwillow Ecological Reserve, located north of the project area. Approximately 740 acres of additional impacts would occur to various agricultural land types (alfalfa, orchards, and row crops) and existing disturbed lands. Collectively, these habitats provide forage, breeding, dispersal and movement, and cover values to a number of special-status wildlife including San Joaquin kit fox, blunt-nosed leopard lizard, giant kangaroo rat, Tipton kangaroo rat, San Joaquin antelope squirrel, San Joaquin pocket mouse, short-nosed kangaroo rat, Swainson's hawk, and burrowing owl as well as a number of rare, declining special-status plant species.

HECA is proposed for an area located in a San Joaquin kit fox Core Recovery Area known as natural lands of western Kern County, which include critical dispersal and connection points between the Elk Hills, Buena Vista Valley, and Lokern Natural Areas, and urban Bakersfield satellite populations of kit fox. The Recovery Plan states that the Carrizo Plain and western Kern County San Joaquin kit fox populations are important for kit fox recovery and preliminary population viability analyses indicate that the possibility of the extinction of this species dramatically increases if either the Carrizo Plain or western Kern County populations are eliminated (USFWS 1998). Staff estimates the project's impacts to 773 acres of habitat represents a loss of denning and regional movement lands for San Joaquin kit fox. HECA would not result in the construction of any new roads although certain intersections would need improvements such as the addition of turn lanes; however, construction and operation would contribute considerable amounts of increased traffic on several local and collector roads that intersect with other irrigation canals that kit fox are known to use for movement. Staff believes increased vehicle traffic from the project, especially non-peak traffic during dawn, dusk and nighttime hours, could result in a considerable increase in vehicle-fox strike mortality and all wildlife that occurs on or near roadways. Staff has proposed Condition of Certification **BIO-7**, which requires that the applicant conduct focused den surveys prior to construction for San Joaquin kit fox and American badger, establish exclusion zones, and continue monitoring the activity of potential dens identified in active construction areas. Condition of Certification **BIO-7** also requires that the applicant follow the USFWS's *Standardized Recommendations for Protection of the San Joaquin Kit Fox Prior to or during Ground Disturbance* for avoiding impacts to this species (USFWS 2011). Staff's proposed Condition of Certification **BIO-12** requires that the applicant prepare and implement a Small Mammal Relocation Plan. In addition, staff has proposed Conditions of Certification **BIO-13** (giant kangaroo rat) and **BIO-14** (Tipton kangaroo rat and San Joaquin antelope squirrel) which requires that the applicant perform focused preconstruction surveys and mapping for giant kangaroo rat precincts and small mammal burrows, preconstruction trapping and relocation in order to minimize and avoid take of small burrowing mammals in active construction areas, and burrow excavation once burrows and precincts have been completely trapped and evaluated for small mammal presence.

Blunt-nosed leopard lizard (BNLL) is a California Fully Protected species under California Fish and Game Code Section 5050 and therefore, incidental take of the species is not legally permitted as defined bySection 86 of the Fish and Game Code. This species is present at the Elk Hills Oil Field and has a high potential to occupy the proposed carbon dioxide pipeline route as well as disturbed allscale scrub areas along the natural gas pipeline. The construction of the project would impact approximately 192 acres of natural allscale scrub and disturbed lands which provide small mammal burrow habitat for BNLL; this poses a threat to BNLL in the form of mortality from vehicles and equipment on roadways, entrapment in construction-related trenches or pipes, burial in burrows by equipment, avoidance of certain habitats, modification to breeding and/or foraging behaviors, and reduced carrying capacity of natural scrub habitat and neighboring lands known to be occupied by BNLL. Staff has proposed Condition of Certification **BIO-8** which requires that the applicant prepare and implement a Blunt-nosed Leopard Lizard Impact Avoidance and Minimization Plan to further minimize the potential for take during construction and operation of the project. In particular, this plan would take into consideration the phasing of linear construction and how clearance surveys, exclusion fencing, and fence and burrow monitoring would also be phased in order to ensure BNLL remain clear of active construction areas. Condition of Certification **BIO-8** also requires that various impact avoidance measures be incorporated including scheduling surface ground disturbing during the BNLL's active season (approximately April 15 to October 15) to the greatest extent practicable, particularly in habitat areas where this species is mostly likely to be encountered, minor shifts in proposed pipeline alignments in order to avoid potentially occupied small mammal burrows, and presence of biological monitor(s) in active construction areas. Scheduling surface ground- disturbing activities during the BNLL active season would make it more likely to guarantee that BNLL are above ground, active, and able to escape from construction activities. Staff concludes that even with the implementation of staff's proposed take avoidance and minimization measures, incidental take of blunt-nosed leopard lizard would likely occur over the life of the project. Therefore, staff considers this impact significant and unavoidable under CEQA even with the incorporation of mitigation. It is also unclear whether the project would comply with Fish and Game Code Section 5050 relating to Fully Protected Reptile and Amphibian Species and the California Endangered Species Act since avoiding take of this species cannot be guaranteed for the life of the project.

During protocol-level surveys performed for Swainson's hawk, 12 active raptor nests were found within the surveyarea, six of which were confirmed Swainson's hawk nests. All six Swainson's hawk nests appear to be within a 0.25 mile of either the project site or a proposed linear facility and therefore could be affected by construction noise or other construction disturbances during the nesting season. The majority of these nest trees occur along canal levees of the Kern River Flood Control Channel, West Side Canal and other smaller unnamed agricultural canals and ditches and are likely supplied to some extent by irrigation runoff that accumulates in irrigation canals as well as groundwater. In addition, valley sink scrub, a sensitive vegetation community identified by the California Natural Diversity Database, potentially occurs in these same areas in association with the Kern River Flood Control Channel. Staff believes that a more definitive analysis is needed on the water source of the nest trees that occur in the project area and pre- and post-project groundwater drawdown around the proposed well field. Staff also believes the loss of approximately 571 acres of agricultural lands including alfalfa, wheat, onion fields, and other low-growing crop types that provide forage value is a significant loss of foraging habitat for Swainson's hawk. More definitive analysis is needed on the baseline groundwater levels and water source of the nest trees and sensitive vegetation communities that occur in the project area. Staff's proposed Condition of Certification **BIO-9** (Swainson's Hawk Impact Avoidance Measures) requires that the applicant perform focused, preconstruction surveys within 0.50-mile of all project facilities and a minimum construction avoidance buffer of 0.50 mile must be implemented around any active Swainson's hawk nests following the recommended survey protocol for this species. Condition of Certification **BIO-9** also requires the applicant to prepare and implement a Swainson's Hawk Monitoring and Mitigation Plan which would account for the phasing of construction and need to phase preconstruction surveys. With the incorporation of the above conditions of certification, the project's impacts to Swainson's hawk habitat would be reduced; however, until additional data is provided regarding the project's impacts and overall mitigation strategy, staff cannot determine if the project's impacts to Swainson's hawk habitat would be reduced to below a level of significance. If groundwater drawdown from HECA's proposed well field and along the 15-mile processed water pipeline is consistent enough over the course of several years, staff believes the decrease in water supply to the tree's root system could result in gradual decline and eventually nest tree failure which may constitute take under the California Endangered Species Act, the Migratory Bird Treaty Act, and California Fish and Game Code 3503; therefore, it is unknown if HECA complies with these LORS at this time.

Staff has proposed several impact avoidance and minimization measures to reduce the potential for impacts to special-status plants and wildlife primarily during construction of the project. Specifically, staff has proposed Conditions of Certification **BIO-1** through **BIO-6** which would apply to all species that could be impacted by the project by requiring the applicant to appoint a Designated Biologist and Biological Monitors for routine monitoring and reporting of the project during construction and implementation of a worker awareness training program. Conditions of Certification **BIO-7** through **BIO-17** are species-specific conditions, which in essence require the applicant to perform focused, preconstruction surveys in suitable habitat areas, implement species-specific construction impact avoidance measures, and monitor for signs of disturbance during construction following wildlife agency protocols. These conditions also require the applicant to prepare species-specific mitigation and monitoring plans specifically for blunt-nosed leopard lizard, Swainson's hawk, burrowing owl, and listed small mammals (giant kangaroo rat, Tipton kangaroo rat, San Joaquin antelope squirrel) outlining construction avoidance procedures while considering a phased construction schedule along linear routes when implementing clearance surveys.

Energy Commssion staff, the California Department of Fish and Wildlife (CDFW), and U.S. Fish and Wildlife Service (USFWS) have determined that permanent protection and perpetual management of compensatory habitat is necessary and required in accordance with CEQA and biological laws, ordinances, regulations, and standards (LORS). This determination is based on factors including an assessment of the importance of the habitat in the project area and the extent to which project activities would impact the habitat. There remains much uncertainty regarding the applicant's overall compensatory mitigation proposal for the project. The applicant submitted a Section 7 Biological Assessment for HECA including the OEHI component of the project on March 1, 2013, (URS 2013b**, Biological Resources Appendix A**). The applicant has proposed to mitigate for permanent and temporary habitat impacts to federally and state listed species at a 0.1:1 and 2.1:1 ratio, respectively, which staff believes would not suffice as adequate habitat compensation for project impacts to special-status species (HECA 2012b, URS 2013b). The applicant has also proposed to purchase habitat credits from the Kern Water Bank as mitigation for the project, which the wildlife agencies have indicated is not a feasible option for mitigating HECA's impacts to special-status wildlife species. The CDFW and USFWS have indicated that while it may be possible to purchase some mitigation credits for a portion of the listed species that would be impacted, it is not feasible to mitigate HECA entirely at the Kern Water Bank, given the nature of the project's impacts to listed wildlife species from project traffic road mortality and habitat loss. During May 2013, the applicant submitted a Section 2081 Incidental Take Permit application for project impacts to state-listed wildlife species for which the applicant would be seeking incidental take coverage which staff has preliminarily reviewed (URS 2013d). Staff has inserted Condition of Certification **BIO-20** (Compensatory Habitat Mitigation for Upland Species) as a placeholder. Staff will continue to work with the applicant, CDFW, and USFWS to develop an appropriate mitigation strategy for HECA that is consistent with the goals and objectives of the *Recovery Plan for Upland Species of the San Joaquin Valley*. Additional conditions of certification, and modifications to currently proposed conditions of certification including Condition of Certification **BIO-20**, are likely to be necessary based on further consultation with the wildlife agencies and information provided by the applicant. With the implementation of staff's proposed Conditions of Certification **BIO-1** through **BIO-20**, impacts to special-status species would be reduced; however, without an adequate mitigation proposal, staff cannot make a determination whether the project would comply with all applicable LORS or that project impacts to sensitive biological resources would be reduced to less than significant levels in accordance with CEQA.

INTRODUCTION

This section of the Preliminary Staff Assessment and Draft Environmental Impact Statement (PSA/DEIS) presents the preliminary conclusions of the California Energy Commission (Energy Commission) staff and the Department of Energy (DOE), hereafter jointly referred to as staff unless otherwise noted, regarding the potential impacts to biological resources from construction and operation of the proposed Hydrogen Energy California (HECA) project. As discussed in the **Introduction** section of the PSA, this document analyzes the project's impacts pursuant to both the National Environmental Policy Act (NEPA) and California Environmental Quality Act (CEQA). The two statutes are similar in their requirements concerning analysis of a project's impacts. Therefore, unless otherwise noted, staff's use of, and reference to, CEQA criteria and guidelines also encompasses and satisfies NEPA requirements for this environmental document.

The HECA project will capture 3 million tons per year of CO_2 and 2.6 million tons per year will be compressed and used for Enhanced Oil Recovery (EOR) at the Elk Hills Oil Field (EHOF) located approximately three miles south of the site. The CO_2 EOR component of HECA (referred to as the OEHI component throughout the remainder of this document) would be permitted by the Division of Oil, Gas and Geothermal Resources (DOGGR) under a Class II Underground Injection Control (UIC) permit. The Class II UIC permit application identifies phase 1 of the OEHI component, which would include 25 injection patterns. OEHI estimates the entire OEHI component would consist of over 200 injection patterns and each injection well would function as a central injection point surrounded by three to five offsetting production wells. OEHI indicated that subsequent pattern areas would be submitted under subsequent UIC permit applications as the OEHI component of HECA proceeds (OEHI 2012c). Staff has analyzed the effects of the OEHI component to the physical environment in accordance with CEQA. Where significant impacts have been identified, staff has provided recommended mitigation measures to the applicable permitting authorities in order to reduce an impact to biological resources to less than significant levels.

The project would impact approximately 773 acres (453 acres for the IGCC facility, 91 acres for staging areas, and 229 acres for linear facilities) of agricultural lands and disturbed natural lands in western Kern County, California (**Biological Resources Table 2**). Information provided in this document addresses potential impacts to special-status species, their habitats, and areas of critical biological concern for all impact areas mentioned above. This document explains the need for mitigation, evaluates the adequacy of mitigation proposed by the applicant, and specifies additional mitigation measures to reduce the project's impacts. It also describes compliance of the project with applicable laws, ordinances, regulations, and standards and recommends conditions of certification for the project.

This analysis is based, in part, upon information provided in the Amended Application for Certification for Hydrogen Energy California, Kern County (HECA 2012b), several responses to staff's data requests from the applicant and OEHI regarding the proposed carbon dioxide pipeline, public issue resolution workshops conducted on behalf of the project on April 12, 2010, September 27, 2012, and November 7, 2012; site visits performed by biology staff on April 12, 2010, May 12, 2012, and October 17, 2012 of the proposed HECA facilities and EHOF; review of the USFWS's *Recovery Plan for Upland Species of the San Joaquin Valley* (Recovery Plan, USFWS 1998); Section 7 Biological Assessment submitted for HECA (**Biological Resources Appendix A**, URS 2013b); and communications and correspondence with representatives from CDFW and USFWS.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The project will need to abide by the Laws, Ordinances, Regulations, and Standards (LORS) listed in **Biological Resources Table 1** during project construction and operation.

Biological Resources Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	
Endangered Species Act (Title 16, United States Code, section 1531 et seq., and Title 50, Code of Federal Regulations, part 17.1 et seq.)	Designates and provides for protection of threatened and endangered plant and animal species and their critical habitat. "Take" of a federally listed species is prohibited without an incidental take permit, which may be obtained through Section 7 consultation (between federal agencies) or a Section 10 Habitat Conservation Plan.
Migratory Bird Treaty Act (Title 16, United States Code, sections 703 through 711)	Makes it unlawful to take or possess any migratory nongame bird (or any part of such migratory nongame bird) as designated in the Migratory Bird Treaty Act.
Clean Water Act Section 404 (Code of Federal Regulations Title 33, Chapter 26, Subchapter 4 Section 1344)	Requires the permitting and monitoring of all discharges to surface water bodies. Section 404 requires a permit from the U.S. Army Corps of Engineers (Corps) for a discharge of dredged or fill materials into waters of the U.S., including wetlands. Section 401 requires a permit from a regional water quality control board (RWQCB) for the discharge of pollutants. By federal law, every applicant for a federal permit or license for an activity that may result in a discharge into a California water body, including wetlands, must request state certification that the proposed activity will not violate state and federal water quality standards.
Bald and Golden Eagle Protection Act (Title 16, United States Code section 668)	Provides for the protection of the bald eagle and the golden eagle by prohibiting, except under certain specified conditions, the take, possession, and commerce of such birds. The 1972 amendments increased penalties for violating provisions of the act or regulations issued pursuant thereto and strengthened other enforcement measures. Rewards are provided for information leading to arrest and conviction for violation of the act.
Eagle Act (Title 50, Code of Federal Regulations, section 22.26)	Would authorize limited take of bald eagles (*Haliaeetus leucocephalus*) and golden eagles (*Aquila chrysaetos*) under the Eagle Act, where the taking is associated with, but not the purpose of activity, and cannot practicably be avoided.
Eagle Act (Title 50, Code of Federal Regulations, section 22.27)	Would provide for the intentional take of eagle nests where necessary to alleviate a safety hazard to people or eagles; necessary to ensure public health and safety; the nest prevents the use of a human–engineered structure, or; the activity, or mitigation for the activity, will provide a net benefit to eagles. Only inactive nests would be allowed to be taken except in the case of safety emergencies.

State	
California Endangered Species Act of 1984 (Fish and Game Code, sections 2050 through 2098)	Protects California's rare, threatened, and endangered species. "Take" of a state-listed species is prohibited without an Incidental Take Permit.
Definition of "Take" (Fish and Game Code section 86)	Defines take as to hunt, pursue, catch, capture, or kill, or attempt to hunt, pursue, catch, capture, or kill.
Protected furbearing mammals (Title 14, California Code of Regulations, section 460)	Fisher, marten, river otter, desert kit fox and red fox may not be taken at any time.
California Code of Regulations (Title 14, sections 670.2 and 670.5)	Lists the plants and animals of California that are declared rare, threatened, or endangered.
Fully Protected Species (Fish and Game Code, sections 3511, 4700, 5050, and 5515)	Designates certain species as fully protected and prohibits the take of such species or their habitat unless for scientific purposes (see also Title 14 California Code of Regulations, section 670.7).
Nest or Eggs (Fish and Game Code section 3503)	Protects California's birds by making it unlawful to take, possess, or needlessly destroy the nest or eggs of any bird.
Birds of Prey (Fish and Game Code section 3503.5	Unlawful to take, possess, or destroy any birds in the orders Falconiformes and Strigiformes or to take, possess, or destroy the nest or eggs of any such bird.
Migratory Birds (Fish and Game Code section 3513)	Protects California's migratory birds by making it unlawful to take or possess any migratory nongame bird as designated in the Migratory Bird Treaty Act or any part of such migratory nongame birds.
Nongame mammals (Fish and Game Code section 4150)	Makes it unlawful to take or possess any non-game mammal or parts thereof except as provided in the Fish and Game Code or in accordance with regulations adopted by the commission.
Ecological Reserves (Fish and Game Code Section 1580 et seq)	Designates land or land and water areas that are to be preserved in a natural condition, or which are to be provided some level of protection, for the benefit of the general public to observe native flora and fauna and for scientific study or research.

Streambed Alteration Agreement (Fish and Game Code sections 1600 et seq.)	Regulates activities that may divert, obstruct, or change the natural flow of the bed, channel, or bank of any river, stream, or lake in California designated by CDFW in which there is at any time an existing fish or wildlife resource or from which these resources derive benefit. Impacts to vegetation and wildlife resulting from disturbances to waterways are also reviewed and regulated during the permitting process.
Porter-Cologne Water Quality Control Act	Regulates discharges of waste and fill material to waters of the State, including “isolated” waters and wetlands through regional water boards, their basin plans, and Waste Discharge Requirements (WDRs). WDRs protect pre-identified beneficial uses that often include rare, threatened, and endangered species and wildlife habitat. California establishes its regulations to comply with CWA under the Porter-Cologne Water Quality Act.
California Native Plant Protection Act of 1977 (Fish and Game Code section 1900 et seq.)	Designates state rare, threatened, and endangered plants.
Local	
Kern County General Plan Land Use, Open Space, and Conservation Element (Kern County 2007)	Directs the county to work closely with state and federal agencies to assure that discretionary projects avoid or minimize impacts to fish, wildlife, and botanical resources.

PROPOSED PROJECT

SETTING AND EXISTING CONDITIONS

<u>Proposed Project</u>

HECA proposes to construct and operate an integrated gasification combined cycle (IGCC) facility in western Kern County, California on 453 acres (project site). In addition to the IGCC facility, there are five proposed linear facilities that would require construction in order for the project to operate and two additional alternatives for coal transportation to the project site, a proposed railroad spur or a trucking route. Collectively, the project site and linear facility footprints are defined as the project area throughout the remainder of this document. The linear facility routes include a proposed transmission line and PG&E switching station, potable water pipeline, processed water pipeline and well field, natural gas pipeline, and carbon dioxide pipeline. HECA would also include a controlled buffer area, a 653-acre area immediately adjacent to the project site that is open for purchase by the applicant with the intent that the applicant would be able to control public site access and ownership surrounding the project site. An additional 91 acres would be usedfor temporary construction staging and would be located between Adohr Road and the northern boundary of the project site (HECA 2012b). In addition, OEHI is proposing to inject high volumes of compressed carbon dioxide (CO_2) to facilitate oil production, increase recoverable oil reserves, and ultimately extend the productive life of the Elk Hills Unit. This portion of HECA is known as the OEHI component.

Regional Setting

HECA is proposed for an area in western Kern County, which is located in the San Joaquin Valley basin, the southern portion of the Great Central Valley of California. The San Joaquin Valley basin is defined by the Coast Ranges to the west, the San Emigdio and Tehachapi Mountains to the south, the Sierra Nevada mountain range to the east, and the delta of the San Joaquin and Sacramento Rivers to the north. Kern County extends beyond the southern slope of the Sierra Nevada range into the Mojave Desert towards the western portion of the county. The Carrizo Plain National Monument is located approximately 23 miles west of the project area and the Kern and Pixley National Wildlife Refuge is located approximately 34 miles northwest of the project area.

Water supply within Kern County is primarily provided by groundwater, the Kern River and other surface water features and imports, which include inputs from the California State Water Project via the Friant-Kern Canal and the Central Valley Project via the California Aqueduct. In Kern County, approximately 60 percent of water used for agricultural and residential uses is pumped from groundwater and agriculture uses almost 90 percent of the water consumed in the region.

The project occurs in a very rural, agricultural setting. HECA is proposed for an area northeast of the former Elk Hills Naval Petroleum Reserve-1 (NPR-1) and NPR-2, presently the EHOF. This area supports several water diversion structures and bypass channels including the California Aqueduct, the Kern River Flood Control Channel, the West Side Canal, and the Kern River and Kern River Drainage floodplain area, among several other unnamed ditches and canals associated with these water diversion facilities. Topographically, the EHOF consists of an east-west trending ridge about 16 miles long by 6 miles wide and is located approximately 26 miles southwest of Bakersfield in western Kern County in the southern San Joaquin Valley. The EHOF is an approximate-48,000 acre active oil field with significant levels of disturbance in high production areas. Past disturbances which have altered habitat conditions on EHOF include grazing, wild fires, and ongoing oil and gas operations. Elevations across the EHOF range from approximately 300 to 1,550 feet above mean sea level; steep ephemeral drainages with incised banks are found within the interior of the EHOF with flat valleys and alluvial plains on the perimeter (HECA 2012b, Appenidx A). The EHOF consists of NPR-1 and NPR-2. NPR-1 consists of approximately 47,409 acres and is surrounded on three sides by oil and gas fields and agricultural lands.

On the north side, NPR-1 is contiguous with a large area of relatively undisturbed habitat known as the Lokern Road area (URS 2012d). Also located north of EHOF, is the Lokern Ecological Preserve (LEP), approximately 3,900 acres in size. McKittrick Valley and portions of Buena Vista Valley with Highway 33 running northwest-southeast are to the west of the EHOF. The cities of McKittrick and Derby Acres are located along Highway 33 and approximately ten miles farther to the west and across the Temblor Range is the Carrizo Plain National Monument, an Area of Critical Environmental Concern. To the south and partially contiguous with NPR-1 is the Buena Vista Valley

and NPR-2; the NPR-2 is approximately 30,000 acres in size and was recently transferred from DOE ownership to the Bureau of Land Management. Natural vegetation on NPR-1 consists primarily of valley saltbush scrub, sink scrub, and non-native grassland habitat (HECA 2012b, Appendix A). Lands to the east include Coles Levee Ecological Preserve (approximately 6,059 acres), the Kern Water Bank Authority (approximately 19,900 acres), the Tule Elk State Reserve and the Kern River. The Buena Vista Lake Bed is located immediately southeast of Highway 119.
Several natural resource conservation areas occur in the project area including the following (**Biological Resources Figure 1**):

- The EHOF has been heavily studied and monitored for biological resources for over 30 years. Currently, a California Endangered Species Act (CESA) Memorandum of Understanding (MOU) between CDFW and OEHI in conjunction with a 1995 USWFS Biological Opinion (BO, URS 2012d) prescribe measures to avoid, minimize, and mitigate adverse effects to listed plant and wildlife species, one measure of which is the designation of a 7,075-acre conservation area on and adjacent to the Elk Hills Unit. Populations of special-status wildlife species known to occur at Elk Hills include San Joaquin kit fox, giant kangaroo rat, Tipton kangaroo rat, blunt-nosed leopard lizard, San Joaquin antelope ground squirrel, burrowing owl, among other wildlife and many plants considered rare, threatened, or endangered by the California Native Plant Society (CNPS) are known to occur on the EHOF and are essential to the continued existence of these species;

- The approximate 950-acre Tule Elk State Reserve is located south of the community of Buttonwillow between HECA and the Kern Water Bank and has been a refuge for tule elk for over 60 years. In the San Joaquin Valley, the remaining elk range was limited to the willow and tule-filled marshes between Buena Vista and Tulare Lakes; however gradually these lands disappeared as the area was diked, drained, and cleared for agriculture. As early as 1912, proposals were made to provide a fenced preserve near Buena Vista Lake in Kern County and protect the depleting elk population from local agricultural interests. In 1932, the State Park Commission purchased 953 acres near the town of Tupman and the new Tupman Reserve was completely fenced to enclose the elk. In 1954, management of the 41 surviving elk in the Tupman Reserve was turned over to California State Parks which devised a feeding program and constructed artificial ponds for the elk to use (California State Parks 2004, Harrison et al 1987); however, past management practices have resulted in a degraded ecosystem unable to support the elk herd without supplemental feeding. Funding has been secured to keep the park open and an endowment has been set up to feed the elk herd (pers. comm.California State Parks). Presently, tule elk have access to approximately 600 acres inside the Tule Elk State Reserve (Pers. comm. California State Parks). Long-term monitoring surveys indicate the Tule Elk State Reserve also supports the following special-species: western burrowing owl, San Joaquin kit fox, blunt-nosed leopard lizard, Tipton kangaroo rat, San Joaquin pocket mouse, San Joaquin antelope squirrel, a large population of slough thistle, among many other common and special-status plant and wildlife species (Pers. comm. California State Parks);

- The Lokern Ecological Reserve (LER) is comprised of parcels previously designated as mitigation lands under the Bakersfield Metropolitan Habitat

Conservation Plan that were in time deeded over to CDFW as conservation lands. The LER consists of several disjunct parcels along both sides of the California Aqueduct between Elk Hills Road and 7th Standard Road. The LER is part of the much larger Lokern Natual Area which includes over 40,000 acres of high-quality habitat for various wildlife and plant species of the San Joaquin Valley. The LER supports similar species as those discussed above as well as occurrences of western pond turtle, California tiger salamander, tricolored blackbird, short-nosed kangaroo rat, giant kangaroo rat, and slough thistle, a sensitive plant that occurs in alkali meadows and flats in the southern San Joaquin Valley are also known from the LER;

- The Buttonwillow Ecological Reserve (BER) is known to support several rare plant species including heartscale, lesser saltscale, Lost Hills crownscale, Kern mallow, and San Joaquin woolythreads and sensitive wildlife species such as blunt-nosed leopard lizard, California horned lizard, Swainson's hawk, San Joaquin antelope squirrel, Tipton kangaroo rat, Buena vista lake shrew, and San Joaquin kit fox;

- The Department of Water Resources is pursuing a Habitat Conservation Plan (HCP) and a companion State Incidental Take (Section 2081) Permit, collectively the draft California Aqueduct Habitat Conservation Plan area, for the entire length of the California Aqueduct that occurs between Kettleman City and the Grapevine area along Interstate 5. The HCP is in draft form and not permitted, to date.

- The Kern Water Bank, operated by the Kern Water Bank Authority recharges, stores, and recovers groundwater in the Bakersfield area and includes several thousand acres of recharge basins and recovery wells (HEI 2009a). A portion of the Kern Water Bank is also a mitigation bank that is permitted and authorized to sell mitigation credits to developers as project mitigation for impacts to a select number of species; and

- The Coles Levee Ecosystem Preserve (CLEP) is located approximately 3.5 miles southeast of the project area. CLEP, a working oil field, is a preserve that was established through an agreement between ARCO, CDFW, and USFWS. It was an operating mitigation bank for projects that impacted threatened and endangered species in the project area vicinity, but the mitigation bank credits have been sold out for some time. CLEP is currently managed by Aera Energy and CDFW holds a permanent conservation easement over all of CLEP. CLEP supports grassland, alkali marsh, and saltbush scrub habitats and there are known occurrences of special-status plants including slough thistle, oil nest straw, San Joaquin bluecurls, Hoover's eriastrum, recurved larkspur, and gypsum-loving larkspur. Wildlife species known from CLEP include San Joaquin antelope squirrel, Heerman's kangaroo rat, Tipton kangaroo rat, short-nosed kangaroo rat, American badger, San Joaquin pocket mouse, blunt-nosed leopard lizard, western spadefoot toad, golden eagle, burrowing owl, and prairie falcon among many other common and rare wildlife species.

Habitat Types

The project area supports five main habitat communities as discussed in more detail below and summarized in **Biological Resources Table 2**.

Biological Resources Table 2:
Upland Habitat Types within Project Area[1]

Vegetation Community/Cover Type in project area	Project Site and construction laydown	Linear Facility	Total
Allscale scrub/natural vegetation	0	32.7	32.7
Alfalfa	177.8	25.54	203.34
Other row crops	337.3	31.13	368.43
Orchards	0	8.91	8.91
Developed/disturbed	28.9	130.85	159.75
Total	**544.0**	**229.13**	**773.13**

Project Setting

Vegetation and Wildlife

Allscale scrub and several agricultural crop types characterize the biological communities within the project area. Although the individual crop types do not translate into habitat types identified by resource databases or agencies, farmed agricultural land still provides biological value to wildlife as described in more detail below.

Areas along Stockdale Highway and Highway 58 are characterized primarily by almond orchards, farmed lands of alfalfa, cotton, and corn, and occasional dairy farms and homesteads with irrigation canals and raised levee roads between fields. Natural habitat areas of allscale scrub are interspersed between actively cultivated areas and lower elevation erosional drainages. Besides pistachio and almond orchards, alfalfa and other row crops are generally dense and low growing.

The proposed carbon dioxide pipeline route located on the lower flanks of the Elk Hills and immediately north of a portion of the Elk Hills conservation area is the linear route that supports the most contiguous natural, non-farmland type of habitat in the project area. The low-lying washes on the lower flanks of the Elk Hills where the carbon dioxide pipeline route is proposed supports sparse allscale scrub habitat and primarily alkaline soils (HECA 2012b, Appendix A, Attachment A). Non-native annual grassland seems to dominate the carbon dioxide pipeline route although vegetation associated with valley sink scrub is intermixed in low-lying washes. Most of the mammal species on NPR-1 are

[1] These acreages were developed from Data Request Table A56-1, area of habitats and existing land use types within the project area (URS 2013b) and Table A211-1 Disturbed Acreages (URS 2013b) and do not include habitat disturbances associated with the OEHI component which are discussed in the Carbon Capture and Sequestration Enhanced Oil Recovery Project on Elk Hills Unit portion of this PSA section.

rodents; however, the coyote (*Canis latrans*) population on EHOF significantly increased from 1979 to 84 and predation on San Joaquin kit fox (*Vulpes macrotis mutica*) prompted a coyote control program. Most of the bird species that utilize the oil field are either permanent or seasonal residents, with several transient migrant bird species as well. In addition, portions of the natural gas pipeline route also support areas of disturbed, natural allscale scrub primarily Sites 1 through 5 shown on **Biological Resources Figure 2**. Some of these sites represent similar habitat values as the nearby Buttonwillow Ecological Reserve, generally located north of the project site.

Allscale Scrub

Allscale scrub habitat is the dominant natural community in the project area, which is interspersed with non-native annual grasslands and farmed agricultural lands. The proposed linear facilities support approximately 33 acres of natural allscale scrub habitat; however, the project site itself does not support any allscale scrub since it is in active cultivation. Generally, the few natural areas in the project area that are not farmlands, support patches of natural allscale scrub vegetation intermixed with non-native annual grasslands with varying levels of disturbance. The applicant identified natural scrub habitat occurring south of the proposed processed water pipeline between the West Side Canal and Kern River Flood Control Channel (KRFCC), along portions of the natural gas pipeline along Highway 58 and north (HECA 2012b). The KRFCC, Kern Water Bank, Tule Elk State Reserve, the lower flanks of the Elk Hills south of the California Aqueduct, and other interspersed areas support native allscale scrub habitat. Some of the wetter areas with more alkaline soils support alkali sink scrub; however, these areas are not located within the project's footprint of the linear facilities and would not be developed for the project. Previously, the applicant identified the habitat between the canals and south of the water pipeline as allscale riparian scrub (HEI 2009a). These habitats are described in more detail below, but most closely characterize the allscale scrub community and the *Atriplex polycarpha* shrubland alliance and allscale scrub series described in the *Manual of California Vegetation,* Second Edition (URS 2010k).

Allscale scrub is characterized as a low-growing, gray-colored, microphyllous shrub community with succulent shrubs with a height ranging from 0.3 to 1 meter (Holland 1986). Total shrub cover is low, with much bare ground between widely spaced shrubs. The allscale scrub community within the biological survey area is dominated by allscale (*Atriplex polycarpha*) and other associate species including bladderpod (*Isomeris arborea),* and cheesebush (*Hymenoclea salsola*). This vegetation community is equivalent to the *Atriplex polycarpha* shrubland alliance described in the *Manual of California Vegetation,* Second Edition (URS 2010k), which characterizes an *Atriplex polycarpa*-dominated community as the allscale series (Sawyer-Keeler Wolfe 1995). The allscale series has allscale as the sole or dominant shrub in the canopy along with bladderbod, bush buckwheat (*Eriogonum fasciculatum*), cheesebush, honey mesquite (*Prosopis glandulosa*), saltbush (*Atriplex* sp.), and salt grass (*Distichlis spicata*). These communities are also consistent with the San Joaquin saltbush vegetation community described in *Terrestrial Vegetation of California* (Barbour et al 2007). Barbour (2007) describes this community occurring mainly on the southern and western part of the San Joaquin Valley as an open, broad-leaved evergreen or deciduous shrub community with a herbaceous layer that varies from medium density to absent with the structure varying in short distances.

The proposed carbon dioxide pipeline route also supports natural allscale scrub interspersed with non-native grasses and forbes and as indicated above, this facility represents the largest block on non-farmland scrub habitat in the project area, mostly due to its location on the lower flanks of Elk Hills. Non-native annual grassland seems to dominate the carbon dioxide pipeline routealthough vegetation associated with valley sink scrub is intermixed in low-lying washes. Plant species observed along the carbon dioxide route during February 2011 field surveys include non-native grasses and forbs including fiddleneck (*Amsinckia menziesii* var. *intermedia*), red brome (*Bromus madritensis* spp. *rubens*), pepperweed (*Lepidium* sp.), valley popcorn-flower (*Plagiobothrys* sp.), red-stemmed filaree (*Erodium cicutarium*), annual sunflower (*Helianthus annus*), and tidy-tips (*Layia glandulosa*) with occasional saltbush shrubs but shrub density increased in steeper, higher elevations of Elk Hills (HECA 2012b, Volume 2, Appendix A-2 of Appendix A).

Alfalfa, Other Row Crops, and Orchards

The project area supports approximately 203 acres of alfalfa (*Medicago sativa*) fields. Alfalfa occurs in association with neighboring cotton and orchards. Several agricultural ditches conveying irrigation water and farm roads transverse the project area between fields. The project area also supports approximately 368 acres of actively farmed fields of other crop types including cotton, dry onion, safflower, wheat, grape, and corn (**Biological Resources Table 2)**. Various non-native plant species also occur in the project area in association with cultivated agricultural lands that include, in part, curly dock (*Rumex crispus*), plantain grass (*Plantago* sp.), Russian thistle (*Salsola tragus*), fescue (*Vulpia* sp.), and storksbill (*Erodium botrys*) (URS 2009c). Agricultural fields, row crops, orchards, and intermixed irrigation ditches provide a wealth of habitat values to locally common and rare wildlife species. These habitats provide various food, cover, and foraging habitat components for several species of birds, amphibians, reptiles, and small mammals. Common wildlife species observed during various field surveys include common side-blotched lizard (*Uta stansburiana*), bullfrog (*Rana catesbiana*), western toad (*Bufo boreas*), great egret (*Ardea alba*), mourning dove (*Zenaida macroura*), black phoebe (*Sayornis nigricans*), western kingbird (*Tyrannus verticalis*), northern mockingbird (*Mimus polyglottos*), horned lark (*Eremophila alpestris*), raccoon (*Procyon lotor*), and coyote. Several raptor species are known to forage and nest in association with agricultural fields including Swainson's hawk, a state-threatened species that forages primarily over alfalfa fields and other low-growing crop types.

Developed or Disturbed Areas

Approximately 160 acres of disturbed or developed lands occur in the project area, primarily along named canals and channels and farm roads, canal maintenance roads. Areas not designated as row crop, orchard, alfalfa, or natural allscale scrub are considered developed or disturbed (URS 2013b)

Sensitive Vegetation Communities

The California Natural Diversity Database (CNDDB) identifies three sensitive vegetation communities occurring within a 10-mile radius of the project area including Great Valley mesquite scrub, valley saltbush scrub, and valley sink scrub (CDFG 2012, HECA 2012b). These vegetation communities have a global and state rank of either G1 or G2 and S1 or S2 indicating that the communities are critically imperiled globally and very threatened statewide.

Alkali sinks are drainage basins that have soils high in soluble salts and the basins are typically dominated by halophytes (plants tolerant of alkaline and saline soils) (USFWS 1998). Alkali sinks in the San Joaquin Valley typically support scrub plant communities such as alkali playa and valley sink scrub. Valley sink scrub is characterized by low, open dense succulent plants dominated by alkaline-tolerant chenopod shrubs (e.g. *Allenrolfea occidentalis* and *Sueda* sp.) with little understory or a sparse herbaceous layer. In these communities, high groundwater supplies water to perennial plants; historically, perennial plant species drew water from the high groundwater table associated with Kern, Buena Vista, Tulare, and Goose Lakes in the San Joaquin Valley (Garcia and Associates 2006). Several anthropogenic activities have caused the loss and degradation of these natural communities and species associated with them since the mid-1800s from livestock grazing, water impoundment, diversion, and stream channelization primarily due to urbanization and agricultural development (USFWS 1998).

Sections of the KRFCC that run adjacent to the proposed processed water pipeline support areas of valley sink scrub and valley saltbush scrub; however, this linear facility would not directly impact the KRFCC although gradual groundwater drawdown could potentially cause a long-term decline in these rare plant communities. In addition, small, interrupted sections of willow (*Salix* sp.), Fremont's cottonwood (*Populus fremontii*), and tamarisk occur along the KRFCC and the West Side Canal and between agricultural fields; however these areas are not considered well-developed riparian scrub communities due to lack of developed, multi-layered canopy, low cover, and low species diversity. Fremont cottonwoods are the single-most important riparian species in California since this species dominates the few remaining riparian forests in the Central Valley and other riparian areas throughout cismontane and transmontane California (Warner and Hendrix, ed. 1984). However, due to water diversion and reclamation projects, stream channelization, and unregulated clearing of riparian areas since the early 1900s and even early since the pre-settlement era due to gold mining, riparian communities have drastically declined in acreage and habitat quality and typically only occur in small stands. Extant riparian communities in the San Joaquin Valley are estimated to be approximately 7,000 acres and exist as degraded, narrow stands of riparian vegetation along channelized streams (USFWS 1998).

Waters of the United States (including Wetlands)

For purposes of DOE, this section of the PSA/DEIS describes wetlands potentially affected by the construction and operation of HECA. This section also analyzes the potential direct and indirect effects of the proposed project on wetlands. This section provides the required wetland assessment and this PSA/DEIS provides an opportunity for public review in compliance with regulations promulgated at 10 CFR 1022, "Compliance with Floodplain and Wetland Environmental Review Requirements." These regulations provide a guide for DOE compliance with Executive Order (EO) 11990, “Protection of Wetlands.” EO 11990 requires that federal agencies, while planning their actions, consider alternatives to affecting wetlands, if applicable, and limit adverse impacts to the extent practicable if impacts cannot be avoided.

The applicant mapped a total of 187.91 acres of water features within the project area, of which 92.51 acres were identified as potential waters of the U.S. including portions of the West Side Canal/Outlet Canal; Kern River Flood Control Channel; East Side Canal; California Aqueduct; several agricultural ditches, canals, and stock ponds that connect to these features; and depressional wetland areas (URS 2012a). The following features were identified as potential Waters of the U.S. (URS 2013c):

- Seasonally ponded depressions (2.93 acres);
- California Aqueduct (1.70 acres); and
- Kern River Flood Control Channel (87.88 acres).

The applicant performed formal wetland delineation surveys of the project area during December 2010 and March 2012 and submitted revised waters of the U.S. maps to staff showing the location of delineated waters of the U.S. (URS 2012a); likewise, the applicant submitted a Jurisdicitonal Delineation report and Nationwide Permit Preconstruction Notification 33 during March 2013 (URS 2013c) which staff has prelimarily reviewed.

Several depressional wetland areas were mapped along disturbed, shoulder areas north and south of Highway 58 where the natural gas pipeline linear is proposed. This area is highly disturbed from development of Highway 58, the San Joaquin Valley Buttonwillow Railroad line, and farmland harvest activities and farm roads south of the highway. Generally speaking, these features do not support all three wetland criteria parameters (hydrophytic vegetation, hydric soils, and wetland hydrology) to be classified as wetlands and were therefore identified as non-jurisdictional waters. The majority of these features support sufficient hydrology to sustain ponded water for a sufficient period of time and exhibit hydric soil indicators due to ponding; however, most features do not support hydrophytic vegetation. One feature, WL-1 located north of Highway 58, does support hydrophytic vegetation and was identified as a wetland feature. However, the extent of Corps jurisdiction over these delineated features under Section 404 of the Clean Water Act has not been determined at this time.

The Kern River flows west to southwest through the city of Bakersfield and under Highway 119 in the project area. The Kern River occurs approximately five miles southeast of the project area and therefore would not be directly affected by the project. The KRFCC supports natural, alkali scrub habitat and is an overflow channel to the Kern River. In previous Jurisdictional Determinations made by the Corps in the project vicinity, the Corps has taken jurisdiction over the Kern River and the KRFCC since it is tributary to the Kern River. The applicant has identified the West Side Canal, East Side Canal, and all connecting basins and drainage ditches as non-jurisdictional; however, since these two named canals connect to the Kern River and two lakes in the Buena Vista Aquatic Recreation Area, Lake Evans and Lake Webb (HECA 2012b), the Corps may have Section 404 jurisdiction over these features as well. Typically, the U.S. Army Corps of Engineers (Corps) would not have Clean Water Act Section 404 jurisdiction over irrigation ditches or canals excavated in uplands that drain uplands; however, the Corps often determines its extent of jurisdiction while taking into consideration the local hydrology and surface water connections specific to the project area.

Waters of the State

Some or all of the potential federally jurisdictional waters described above may also fall under state jurisdiction. CDFW typically does not have jurisdiction over agricultural stock ponds or detention basins; however, some canals do fall under Fish and Game Code Section 1600 jurisdiction. CDFW has taken jurisdiction over portions of the Kern River Flood Control Channel for other projects primarily due to the presence of a defined bed and bank with alkali sink habitat and direct overland flow connection to the Kern River. Since the West Side Canal was constructed to convey irrigation water from the Kern River to nearby fields, this feature would not likely fall under Section 1600 jurisdiction (CDFW, pers comm. October 2012). The applicant has proposed HDD for the carbon dioxide pipeline under the West Side Canal, KRFCC, and California Aqueduct (HECA 2012b). CDFW has indicated since the proposed HDD activities could result in a frac-out into waterways during drilling, a HDD plan is needed along with submittal of the project's notification of a Lake or Streambed Alteration to CDFW (CDFW, pers comm. October 2012). The applicant submitted a Notification of a Lake or Streambed Alteration package to the agencies including a draft HDD Plan during May 2013 which staff has preliminarily reviewed (URS 2013d).

Ephemeral Drainages

The carbon dioxide pipeline route occurs in a transitional area between higher topographic areas from the Elk Hills towards the lower flanks of the Elk Hills and lowland valley areas. As a result, the proposed route supports several ephemeral drainages with a defined bed and bank that likely convey water for a short period following rain events, but otherwise remain dry. Drainages in the higher foothill elevation areas consist of defined washes approximately 3 to 10 feet wide with very little vertical erosion while lowland area drainages consist of low (sink) zones with approximately 4 to 10 feet of vertical erosion and steeply incised channels (HECA 2012b, Appendix A, Attachment A). The ephemeral drainages may fall under Fish and Game Code Section 1600 jurisdiction.

Special-Status Species

Special-status species are plant and wildlife species that have been afforded special protection and recognition by federal, state, or local agencies and environmental protection laws such as those identified in **Biological Resources Table 1**. Listed and special-status species are of relatively limited distribution and often times require specialized habitat conditions. Special-status species are defined as meeting one or more of the following criteria:

- listed as Threatened or Endangered or candidates for future listing under the California Endangered Species Act (CESA) or Federal Endangered Species Act (FESA);
- protected under other regulations (e.g. Migratory Bird Treaty Act);

- listed as Species of Concern by CDFW;
- a plant species considered by the California Native Plant Society (CNPS) to be "rare, threatened, or endangered in California" (CNPS List 1A, 1B, and 2) as well as CNPS List 3 and 4 plant species[2];
- a plant listed as rare under the California Native Plant Protection Act ;
- considered a locally significant species, that is, a species that is not rare from a statewide perspective but is rare or uncommon in a local context such as within a county or region or is so designated in local or regional plans, policies, or ordinances; or
- any other species receiving consideration during environmental review under CEQA Section 15830, including species not protected through state or federal listing but nonetheless demonstrable as "endangered" or "rare" under CEQA.

Special-status species considered for this analysis are based on information provided in the Amended AFC (HECA 2012b), species queries of the California Natural Diversity Database (CDFG 2012), species list provided in the 1997 Final SEIS/PEIR for the sale of Naval Petroleum Reserve-1 (OXY 2012c), USFWS's online list for federally listed species, and CNPS online list for potentially occurring rare plants on the *East Elk Hills, CA* 7.5-minute topographic quadrangle map (USGS 1954, photorevised 1974) and nine surrounding quadrangles, plant and wildlife species known to occur or potentially occurring on EHOF, correspondence with the applicable resource agencies, and species covered under the Recovery Plan (USFWS 1998).

Biological Resources Table 3 lists special-status species that are known to occur or could potentially occur in the project area and vicinity and therefore, could potentially be impacted by the project. Several special-status plant species were found during biological surveys along the linear facilities, primarily along the proposed carbon dioxide pipeline route as indicated in **Biological Resources Table 3**.

As indicated in **Biological Resources Table 4**, several special-status wildlife species were either detected during field surveys performed in support of the currently proposed project or former project versions of HECA or are known to occur in the project area and therefore considered present or highly likely to occur, primarily in association with the Elk Hills region.

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[2] List 3 plants may be analyzed under CEQA §15380 if sufficient information is available to assess potential impacts to such plants. Factors such as regional rarity vs. statewide rarity should be considered in determining whether cumulative impacts to a List 4 plant are significant even if individual project impacts are not. CNPS List 3 and 4 may be considered regionally significant if, e.g., the occurrence is located at the periphery of the species' range, or exhibits unusual morphology, or occurs in an unusual habitat/substrate. For these reasons, CNPS List 3 and 4 plants should be included in the field surveys and impact analyses. List 3 and 4 plants are also included in the California Natural Diversity Database's (CNDDB) Special Plants, Bryophytes, and Lichens List. [Refer to the current online published list available at: http://www.dfg.ca.gov/biogeodata.]

Biological Resources Table 3
Special-Status Plant Species Known or Potentially Occurring in the Project Area

Common Name	Scientific Name	Status State/Fed/CNPS
Alkali mariposa lily	*Calochortus striatus*	--/--/1B.2
Bakersfield cactus	*Opuntia basilaris* var. *treleasei*	SE/FE/1B.1
Bakersfield smallscale	*Atriplex tularensis*	SE/--/1B.1
Brittlescale	*Atriplex depressa*	--;--;1B.2
Vernal barley	*Hordeum intercedens*	--/--/3.2
California chalk moss	*Pterygoneurum californicum*	--/--/1B.1
California jewel-flower	*Caulanthus californicus*	SE/FE/1B.1
Cottony buckwheat	*Eriogonum gossypinum*	--/--/4.2
Coulter's goldfields	*Lasthenia glabrata* ssp. *coulteri*	--;--;1B.1
Crownscale	*Atriplex coronata* var. *coronata*	--;--;4.2
Forked fiddleneck	*Amsinckia vernicosa* var. *furcata*	--;--;4.2
Gypsum-loving larkspur	*Delphinium gypsophilum* spp. *gypsophilum*	--/--/4.2
Heartscale	*Atriplex cordulata*	--/--/1B.2
Hoover's eriastrum	*Eriastrum hooveri*	--/--/4.2
Horn's milk vetch	*Astragalus hornii* var. *hornii*	--/---/1B.1
Kern mallow	*Eremalche kernensis*	--/FE/1B.1
Lesser saltscale	*Atriplex minuscula*	--/--/1B.1
Lost Hills crownscale	*Atriplex vallicola*	--/--/1B.2
Mason's nest straw	*Stylocline masonii*	--/--/1B.1
Oil nest straw	*Stylocline citroleum*	--/--/1B.1
Recurved larkspur	*Delphinium recurvatum*	--/--/1B.2
San Joaquin bluecurls	*Trichostema ovatum*	--;--;4.2
San Joaquin woollythreads	*Monolopia congdonii*	--/FE/1B.2
Showy golden madia	*Madia radiata*	--/--/1B.1
Slough thistle	*Cirsium crassicaule*	

Common Name	Scientific Name	Status State/Fed/CNPS
		--/--/1B.1
Subtle oracle	*Atriplex subtilis*	--/--/1B.2
Tejon poppy	*Eschscholzia lemmonii* ssp. *kernensis*	--/--/1B.1
Temblor buckwheat	*Eriogonum temblorense*	--;--;1B.2

Sources: CDFW 2012, CNPS 2010

Status Codes:

Federal: FE - Federally listed, endangered: species in danger of extinction throughout a significant portion of its range
FT - Federally listed, threatened: species likely to become endangered within the foreseeable future

State:
SE - State listed as endangered
ST = State listed as threatened

California Native Plant Society:
List 1B - Rare, threatened, or endangered in California and elsewhere
List 2 - Rare, threatened, or endangered in California but more common elsewhere
List 3 - Plants which need more information
List 4 - Limited distribution – a watch list
0.1 - Seriously threatened in California (high degree/immediacy of threat)
0.2 - Fairly threatened in California (moderate degree/immediacy of threat)
0.3 - Not very threatened in California (low degree/immediacy of threats or no current threats known)

Biological Resources Table 4
Special-Status Wildlife Species Known or Potentially Occurring in Project Area

Common Name	Scientific Name	Status State/Federal
Invertebrates		
Ciervo aegialian scarab beetle	*Aegialia concinna*	--/--
Hopping's blister beetle	*Lytta hoppingi*	
Kern shoulderband	*Helminthoglyptacallistoderma*	--/--
Longhorn fairy shrimp	*Branchinecta longiantenna*	--/FE
Moestan blister beetle	*Lytta moesta*	--/--
Molestan blister beetle	*Lytta molesta*	--/--
Morrison's blister beetle	*Lytta morrisoni*	--/--
San Joaquin dune beetle	*Coelus gracilis*	--/--
San Joaquin sootywing skipper	*Pholisora libya*	--/--
Valley elderberry longhorn beetle	*Desmocerus californicus dimorphus*	--/FT
Vernal pool fairy shrimp	*Branchinecta lynchi*	--/FT
Vernal pool tadpole shrimp	*Lepidurus packardi*	--/FE
Fish		
Delta smelt	*Hypomesus transpacificus*	SE/FT
Reptiles and Amphibians		
Blunt-nosed leopard lizard	*Gambelia sila*	SE,SFP/FE/--
California red-legged frog	*Rana draytonii*	CSC/FT
Coast horned lizard	*Phrynosoma blainvillii*	CSC/--
Giant garter snake	*Thamnophis gigas*	ST/FT

San Joaquin whipsnake	*Masticophis flagellum ruddocki*	CSC/--
Silvery legless lizard	*Anniella pulchra pulchra*	CSC/--
Western pond turtle	*Emys marmorata*	CSC/--
Western spadefoot toad	*Spea hammondii*	CSC/--
Birds		
American kestrel	*Falco sparverius*	WL/-- (nesting)
American peregrine falcon	*Falco peregrinus anatum*	SFP/-- (nesting)
Burrowing owl	*Athene cunicularia*	CSC/BCC, BLM Sensitive (burrow sites & some winter sites)
California horned lark	*Eremophila alpestris actia*	WL/--
Cooper's hawk	*Accipiter cooperi*	CSC/--
Ferruginous hawk	*Buteo regalis*	CSC/-- (wintering)
Fulvous whistling duck	*Dendrocygna bicolor*	CSC/-- (nesting)
Golden eagle	*Aquila chrysaetos*	SFP/-- (nesting & wintering)
Greater sandhill crane	*Grus canadensis tabida*	SFP,ST/-- (nesting & wintering)
Least bell's vireo	*Vireo bellii pusillus*	SE/FE (nesting)
Le Conte's thrasher	*Toxostoma lecontei*	CSC,WL/BCC
Little willow flycatcher	*Empidonax traillii brewsteri*	CE/-- (nesting)
Loggerhead shrike	*Lanius ludovicianus*	CSC/--
Long-billed curlew	*Numenius americanus*	WL/BCC (nesting)
Mountain plover	*Charadrius montanus*	CSC/Proposed FT, BCC, BLM Sensitive (wintering)
Northern harrier	*Circus cyaneus*	CSC/-- (nesting)
Osprey	*Pandion haliaetus*	WL/--
Prairie falcon	*Falco mexicanus*	WL/--- (nesting)
Sharp-shinned hawk	*Accipiter striatus*	WL/-- (nesting)
Short-eared owl	*Asio flammeus*	CSC,WL/-- (nesting)
Swainson's hawk	*Buteo swainsoni*	ST,WL/BCC (nesting)
Tricolored blackbird	*Agelaius tricolor*	CSC, WL/BCC, BLM Sensitive (nesting colony)
Western snowy plover	*Charadrius alexandrinus nivosus*	CSC/FT,BCC

Western yellow-billed cuckoo	*Coccyzus americanus occidentalis*	SE/FC,BCC
White-faced ibis	*Plegadis chihi*	WL/--
White-tailed kite	*Elanus leucurus*	SFP/-- (nesting)
Yellow-breasted chat	*Icteria virens*	CSC/-- (nesting)
Yellow-headed blackbird	*Xanthocephalus xanthocephalus*	CSC/-- (nesting)
Yellow warbler	*Dendroica petechia brewsteri*	CSC/-- (nesting)
Mammals		
American badger	*Taxidea taxus*	CSC/--
Buena vista lake shrew	*Sorex ornatus relictus*	CSC/FE
Giant kangaroo rat	*Dipodomys ingens*	SE/FE
Pallid bat	*Antrozous pallidus*	CSC/BLM Sensitive
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	ST/--
San Joaquin kit fox	*Vulpes macrotis mutica*	ST/FE
San Joaquin pocket mouse	*Perognathus inornatus inornatus*	---/BLM Sensitive
Short-nosed kangaroo rat	*Dipodomys nitratoides brevinasus*	CSC/BLM Sensitive
Southern grasshopper mouse	*Onychomys torridus ramona*	CSC/--
Tipton kangaroo rat	*Dipodomys nitratoides nitratoides*	SE/FE
Townsend's big-eared bat	*Corynorhinus townsendii*	CSC/BLM Sensitive
Tulare grasshopper mouse	*Onychomys torridus tularensis*	CSC/BLM Sensitive
Western mastiff bat	*Eumops perotis californicus*	CSC/BLM Sensitive

Status Codes:

Federal:
FE - Federally listed, endangered: species in danger of extinction throughout a significant portion of its range
FT - Federally listed, threatened: species likely to become endangered within the foreseeable future
FC = Federal candidate for listing
BCC: Fish and Wildlife Service: Birds of Conservation Concern: Identifies migratory and non-migratory bird species (beyond those already designated as federally threatened or endangered) that represent highest conservation priorities <www.fws.gov/migratorybirds/reports/BCC2002.pdf>
BLM Sensitive= Bureau of Land Management Sensitive species

State
CSC = California Species of Special Concern. Species of concern to CDFW because of declining population levels, limited ranges, and/or continuing threats have made them vulnerable to extinction.
SE - State listed as endangered
ST = State listed as threatened
R = State listed as rare.
SFP = Fully protected
WL = State Watch List: includes species formerly on California Species of Special Concern List

Special-status Plant Species

Botanical surveys were performed on various dates during March 2009, April and May 2010, and March 2012 for the project areain support of the currently proposed project or former project versions of HECA; non-protocol level botanical surveys for the current carbon dioxide pipeline route were performed during February 2011 and April 2011. Rare plant surveys were performed in suitable habitat areas on previously unsurveyed areas of the linear facilities on March 27 through March 30, 2012; however, rainfall was below average during the late 2011/2012 season and many spring annuals either did not germinate or failed to flower and therefore the 2012 survey season was not a satisfactory season for determining growth and presence or absence of special-status plant species (URS 2012a). Moreover, the majority of unsurveyed areas of Sites 1, 2, 3, and 5 along the natural gas pipeline route were not surveyed in 2012 due to access restrictions (URS 2012a).

The following special-status plant species were either observed during spring 2009, 2010, or 2011 botanical surveys and/or were considered to have a high potential to occur in the project area due to confirmed observations from ongoing long-term monitoring surveys performed on EHOF since 1998:

- Hoover's eriastrum (*Eriastrum hooveri*)
- Gypsum-loving larkspur (*Delphinium gypsophilum* spp*. gypsophilum*)
- Lost Hill's crownscale (*Atriplex vallicola*)
- Cottony buckwheat (*Eriogonum gossypinum*)
- Oil nest straw (*Stylocline citroleum*)
- Recurved larkspur (*Delphinium recurvatum*)
- San Joaquin bluecurls (*Trichostema ovatum*)
- Tejon poppy (*Eschscholzia lemmonii* ssp. *kernensis*)

Hoover's Eriastrum (Eriastrum hooveri, **California Native Plant Society List 4.2*)***

Hoover's eriastrum is an annual herb species on CNPS List 4.2 that grows within chenopod scrubs, grasslands, and gently growing terrain or flats with alkaline, sandy soils from approximately 150 to 2,700 feet elevations in foothill regions (CNPS 2013) but also commonly occurs below 600 feet in elevation (Garcia and Associates 2006). Hoover's eriastrum is known to occur throughout the EHOF in several parcels and sections and has been monitored annually since 1998 (Quad Knopf 2001). A large population of Hoover's eriastrum occurs in the Coles Levee Ecosystem Preserve on the historic Buena Vista Lake bed and on the Elk Hills (Garcia and Associates 2006). Originally, this species was known from 39 historical locations, although by 1986 only 22 of these locations were believed to be extant. Surveys conducted between 1986 and 1990 identified an additional 91 populations and surveys conducted since 1990 have resulted in the identification of even additional populations. It is believed that most extant occurrences of Hoover's eriastrum occur in the following areas: the Lokern-Elk Hills-Buena Vista Hills-Coles Levee-Maricopa-Taft area, the Antelope Plain-Lost Hills-Semitropic area, and the Carrizo Plain-Elkhorn Plain-Temblor Range-Caliente Mountains-Cuyama Valley-Sierra Madre Mountains area (Garcia and Associates 2006).

CNDDB records for this species occur in the vicinity of the Buttonwillow Airfield and the base of Elk Hills from saltbush scrub habitats within existing oil and gas development areas (CDFG 2012). There are 63 records of this species from the Consortium of California Herbaria mostly from Kern, Los Angeles, Fresno, San Luis Obispo, and Santa Barbara counties. Records from Kern County for Hoover's eriastrum are from the general vicinity of Highway 58, Highway 46, Lokern Road, Highway 119, Buttonwillow, and Lost Hills (CCH 2010).

Year 2001 marked the last year of comprehensive floristic surveys at EHOF; however, annual monitoring of changes in Hoover's eriastrum woolly-star abundance relative to other vegetative parameters in response to abiotic factors has been conducted on six sites throughout Elk Hills since 1993. Sites were randomly selected during 1993 based on the then 110 known occurrences of this species on ElK Hills. Annual monitoring of the six sites was completed during April 2011 and mean densities of this species ranged from zero to 9.97 individual plants per square foot. The frequency of occurrence ranged from zero to 70 percent on the six plots. Site #5 is the closest monitoring site to the proposed carbon dioxide pipeline route and the average density was 1.33 plants per square foot at this location (Western Kern Environmental Consulting 2012).

Allscale scrub communities within the project area are potential habitat for Hoover's eriastrum. This species was observed during focused botanical surveys and reconnaissance-level biological surveys. This species was also found during surveys performed for previous versions of the HECA project. A population of approximately 1,000 individuals of Hoover's eriastrum was observed during spring 2009 surveys near the Elk Hills School (URS 2009c) in close proximity to the current carbon dioxide pipeline route. In addition, approximately 100,000 individual plants were found during April and May 2010 field surveys within the formerly proposed natural gas/potable water linear facility and carbon dioxide routes (URS 2010k). Additionally, this species was observed along a roadside during a survey performed on April 14, 2011 along the currently proposed carbon dioxide route (HECA 2012b, Appendix A Attachment A).

***Gypsum-loving Larkspur* (*Delphinium gypsophilum* ssp. *gypsophilum,* California Native Plant Society List 4.2)**

Gypsum-loving larkspur is a CNPS List 4.2 species that the California Native Plant Society considers a species of limited distribution although fairly endangered in California (CNPS 2013); this species typically occurs in chenopod scrubs, cismontane woodland, and foothill grasslands from 300 to 2,500 feet above mean sea level (CNPS 2013). Gypsum-loving larkspur is considered a common plant species on Elk Hills and has been found in 72 sections of Elk Hills since monitoring surveys began in 1995. On Elk Hills, this species commonly occurs on north facing slopes and has not been observed on flat terrain during surveys performed since 1995 in the Elk Hills (Quad Knopf 2001). There are 118 records of this species from the Consortium of California Herbaria primarily from Kern, San Luis Obispo, Fresno, and Merced counties. The nearest records from Kern County are from the Temblor Range of the Coast Ranges near Bitter Creek National Wildlife Refuge, Kettleman Hills, Wheeler Ridge, and along Tupman Road northwest of Taft (CCH 2010).

Allscale scrub habitat in the project area is potential habitat for gypsum-loving larkspur. This species was found during surveys performed along former project linear routes; however, this plant has not been observed within the construction footprints of any current linear routes. During April and May 2010, approximately 100 plants were found within the formerly proposed natural gas/potable water and carbon dioxide route (URS 2010k), although this area is located east of the currently proposed carbon dioxide pipeline and would not be directly impacted.

***Lost Hills Crownscale (Atriplex coronata var.vallicola,* California Native Plant Society List 1B.2)**

Lost Hills crownscale is a CNPS List 1B.2 species indicating that the California Native Plant Society has determined that the species is rare, threatened, or endangered in California. This small, annual herb also occurs in chenopod scrub habitats and valley and foothill grasslands and has also been reported occurring from valley saltbush scrub in the Elk Hills area (CNPS 2013, CDFG 2012). Lost Hills crownscale is considered an uncommon species on the EHOF and has been observed in nine sections since monitoring surveys began in 1995. This species was last surveyed for on Elk Hills during the 2001 comprehensive floristic survey and was primarily found to grow on the southern and eastern flanks of Elk Hills following 1999, 2000, and 2001 surveys (Quad Knopf 2001).

Lost Hills crownscale is a covered species under the Recovery Plan (USFWS 1998) and occurs in valley sink scrubs, saltbush scrubs, non-native grasslands, and alkali meadows. The CNPS reports this species occurs from 150 feet to 1,900 feet elevation (CNPS 2013). However, valley-floor populations occur at elevations of 165 to 280 feet elevation whereas those on the Carrizo Plain range from approximately 1,300 to 2,000 feet in elevation (USFWS 1998). Lost Hills crownscale has been reported from the margins and beds of dried ponds on alkaline soils below 650 feet elevation in the San Joaquin Valley and possibly in the Carrizo Plain of San Luis Obispo County, but plants from the latter location are undescribed (Garcia and Associates 2006). Prior to the 1980s, this species was reported from three general areas: north of Lost Hills, Mendota in Fresno County, and the Carrizo Plain in San Luis Obispo County. In the 1980s, a number of new sites were discovered near the Lost Hills and on the Carrizo Plain and the current distribution and centers of concentration are currently known as: Lost Hills to extreme southern Kings County; Kerman Ecological Reserve in Fresno County; Soda Lake region of the Carrizo Plain; the Lokern-McKittrick area of Kern County; and southwestern Merced County. Additionally, the Lost Hills and Carrizo Plain areas represent the largest metapopulations (USFWS 1998).

There are 68 records of this species from the Consortium of California Herbaria most of which are from Kern, Fresno, and San Luis Obispo counties. The nearest records for this species to the project area include fairly recently reported records (late 1980s) near Buena Vista Slough, Lost Hills, and west of Elk Hills near McKittrick (CCH 2010).

Approximately 80 plants of Lost Hills crownscale were found within the formerly proposed natural gas/potable water pipeline route (URS 2010k), although this species has not been observed within current HECA linear routes. Allscale scrub habitat in the project area is potential habitat for this species.

Cottony Buckwheat (Eriogonum gossypinum, California Native Plant Society List 4.2)

Cottony buckwheat is a CNPS List 4.2 indicating it is of limited distribution and fairly endangered in California (CNPS 2013). Cottony buckwheat occurs in chenopod scrub habitat. Cottony buckwheat is known to occur throughout the EHOF and has been found most prevalently from the northwestern portion of Elk Hills since monitoring surveys began in 1995. On the Elk Hills, this species commonly occurs on south facing slopes in association with wild oat (*Avena* sp.), red brome (*Bromus madritensis* ssp. *rubens*), red-stem filaree (*Erodium botrys*), allscale, bladderpod, and mousetail grass (*Vulpia myros*) (Quad Knopf 2001).

There are 71 records of this species from the Consortium of California Herbaria most of which are from Kern County; the nearest records for cottony buckwheat are from Hart Memorial Park near the Kern River in Bakersfield, Oil City and McKittrick areas, Maricopa Hills, and Elk Hills (CCH 2010). Approximately 500 plants of this species were found during April and May 2010 in a previously proposed route for the carbon dioxide pipeline (URS 2010k); however, this species has not been observed within current linear routes. Due to the presence of suitable habitat, identified occurrences during field surveys and known occurrences from the EHOF, allscale scrub communities in the project area are potential habitat for cottony buckwheat.

Oil Neststraw (*Stylocline citroleum,* California Native Plant Society List 1B.1)

Oil neststraw is a CNPS List 1B.1 indicating it is of limited distribution and the California Native Plant Society considers this species to be rare, threatened, or endangered in California (CNPS 2013). This species is an inconspicuous, low-growing annual herb that lacks showy flowers. Presently, oil nest straw is known from Elk Hills and the Coles Levee Ecosystem Preserve in western Kern County from petroleum-producing areas; however, extant occurrences are known from saltbush scrub communities in undeveloped areas as well. One occurrence of oil nest straw from EHOF is from a steep wash bank with a well-developed cryptobyotic crust (USFWS 1998). Oil nest straw has been found in 61 sections in Elk Hills since monitoring surveys began in 1995 and most prevalently in the northwestern and southeastern portions; it was found most commonly in areas with reduced annual grass cover and sandy soils (Quad Knopf 2001). This species grows in flats and on slopes within valley and foothill grassland and chenopod scrubs from approximately 150 to 1,200 feet elevation and has been reported from both sandy and clay soils. There are ten records of this species in the Consortium of California Herbaria, eight of which are from Kern County; the nearest records are from the Taft and McKittrick areas and two records from the Naval Petroleum Reserve in Elk Hills (CCH 2010).

Approximately 15,000 oil nest straw plants were found during April and May 2010 in the formerly proposed natural gas/potable water pipeline routes and carbon dioxide route (URS 2010k). Additionally, this plant and Hoover's eriastrum were observed along a roadside during a survey performed on April 14, 2011 on the currently proposed carbon dioxide route (HECA 2012b, Appendix A Attachment A). Due to the presence of suitable habitat, identified occurrences during field surveys and known occurrences from the EHOF, all allscale scrub habitat in the project area is potential habitat for oil neststraw.

Recurved Larkspur **(*Delphinium recurvatum,* California Native Plant Society List 1B.2)**

Recurved larkspur is a CNPS List 1B.2 species that the California Native Plant Society considers to be rare, threatened and fairly endangered in California. This species occurs in valley and foothill grasslands, cismontane woodlands, and chenopod scrubs from approximately sea level to 2,300 feet elevation. This species occurs on poorly drained, fine alkaline soils in valley saltbush and alkali sink scrub below 2,000 feet elevation, from Glenn and Butte counties southward to Kern County in the Central Valley. Recurved larkspur is known from several widely scattered occurrence areas, a few which include areas between the Kern National Wildlife Refuge and Interstate 5, west of the Tule Elk Reserve near the base of the Elk Hills, northeast of the Lokern Natural Area, and east of Coles Levee Ecosystem Preserve (Garcia and Associates 2006). There are 159 records (34 records from Kern County) of this species for the entire state from the Consortium of California Herbaria (CCH 2010); the majority of the Kern County occurrences are from the Wasco-Corcoran Highway, Bakersfield, and Elk Hills areas. The nearest CNDDB record is approximately 1.5 miles west of the project site from loamy, saltbush scrub habitat during 1998 (CDFG 2012) and recurved larkspur has been found but is considered uncommon on the northern flank of Elk Hills since monitoring surveys began in 1995 (Quad Knopf 2001). This species was not observed during field surveys performed for the project from 2009 to 2012. Due to the presence of suitable habitat, identified occurrences during field surveys and known occurrences from the EHOF, allscale scrub habitat I the project area is potential habitat for recurved larkspur.

San Joaquin Bluecurls **(*Trichostema ovatum,* California Native Plant Society List 4.2)**

San Joaquin bluecurls is a CNPS List 4.2 species indicating it is fairly endangered in California although of limited distribution (CNPS 2013). This species is known to occur in chenopod scrub and grassland habitats. This species has been found although is considered uncommon on the EHOFsince monitoring surveys begin in 1995 (Quad Knopf 2001).

There are no CNDDB records for this species within a nine topographic quadrangle search around the project site (CDFG 2012). There are 79 records in the Consortium of California Herbaria, 33 of which are from Kern County and the closest records to the project site are approximately five miles north of the Lost Hills, Buena Vista Hills, Wasco, and east Bakersfield areas (CCH 2010). Approximately 250 plants of San Joaquin bluecurls were identified along the formerly proposed natural gas/potable route during April and May 2010 (URS 2010k, URS 2010n); however, this species has not been observed along current linear routes. Allscale scrub habitat in the project area is potential habitat for this species.

Tejon Poppy (*Eschscholzia lemmonii ssp. kernensis,* California Native Plant Society List 1B.1)

Tejon poppy is a CNPS List 1B.1 species that the California Native Plant Society considers to be rare, threatened and fairly endangered in California. Tejon poppy occurs in chenopod scrubs and valley foothill grasslands from approximately 500 feet to 3,000 feet elevation. This species is also a covered plant species in the Recovery Plan. Tejon poppy remains extant in the Elk Hills and possibly six other locations that historically supported this species which surround the lower hills of the southern tip of the San Joaquin Valley. Tejon poppy grows in adobe clay soils and often times only following above-average rain years (USFWS 1998). Tejon poppy has been found in 28 sections of Elk Hills since monitoring surveys began in 1995 and occurred most commonly in foothill grassland habitat at Elk Hills (Quad Knopf 2001).

The nearest CNDDB record is from an area south of the California Aqueduct approximately 3.5 miles west of the project site from valley saltbush scrub habitat and there are many records from the EHOF (Quad Knopf 2001, CDFG 2012). There are six records for this species in the CCH, mostly from eastern Kern County and the Tejon Ranch area (CCH 2010). This species was not observed during surveys performed for HECA from 2009 or 2012; however, due to the presence of suitable habitat, identified occurrences during field surveys and known occurrences from the EHOF, allscale scrub habitat I the project area is potential habitat for Tejon poppy.

Special-status Wildlife Species

The following special-status wildlife species were either observed during field surveys, known to occur, or have a high probability of occurring in the project area:

- Blunt-nosed leopard lizard (*Gambelia sila*)
- Western spadefoot toad (*Spea hammondii*)
- Giant garter snake (*Thamnophis gigas*)
- San Joaquin kit fox (*Vulpes macrotis mutica*)
- San Joaquin antelope squirrel (*Ammospermophilus nelsoni*)
- Tipton kangaroo rat (*Dipodomys nitratoides nitratoides*)
- Short-nosed kangaroo rat (*Dipodomys nitratoides brevinasus*)
- Giant kangaroo rat (*Dipodomys ingens*)
- Buena Vista lake shrew (*Sorex ornatus relictus*)
- Western burrowing owl (*Athene cunicularia*)
- Swainson’s hawk (*Buteo swainsoni*)
- Golden eagle (*Aquila chrysaetos*)

***Blunt-nosed Leopard Lizard* (*Gambelia sila*, Federally Endangered, California Endangered and Fully Protected)**

Blunt-nosed leopard lizard (BNLL), a federally endangered species, state endangered, and CDFW Fully Protected species occurs in open, sparsely vegetated open plains; grasslands; alkali playa sink scrub habitats; canyon floors; broad and sandy washes; and arroyos in the San Joaquin Valley and low-lying foothills (USFWS 1985). Areas with greater than 50 percent ground cover are typically avoided since it is believed that dense vegetation interferes with thermoregulation, hunting ability, mating behavior, and predator defense mechanisms (Garcia and Associates 2006). Their primary food source is insects, but may opportunistically consume other lizards and occasionally plant material. This species' current distribution is generally on undeveloped parcels on the southern San Joaquin Valley floor from primarily the following areas: Kern and Pixley National Wildlife Refuge; Liberty Farms (Antelope and Allensworth); Carrizo and Elkhorn Plains; Buttonwillow, Elk Hills, and Tupman Essential Habitat Areas; north of Bakersfield around Poso Creek; and western Kern County near the towns of Maricopa, McKittrick, and Taft (USFWS 2009). Inventory data of this species in the Elk Hills Naval Petroleum Reserve No. 1 indicate that this species is absent or rare in hilly terrain, but favor adjacent lower slopes and wash systems with variable soil types from gravel, hardpan, or sandy loam (USFWS 1985).

Leopard lizards use small rodent burrows (e.g., abandoned ground squirrel tunnels, or occupied or abandoned kangaroo rat tunnels) for shelter from predators and temperature extremes. Density of BNLL may be correlated with abundance of mammal burrows. When small mammal populations were compared to BNLL abundance in the Kern National Wildlife Refuge, kangaroo rat abundance and frequency of BNLL directly coincided; however similar studies performed in the Pixley National Wildlife Refuge or on BLM-administered lands in southwestern Kern County did not identify a strong correlation between BNLL abundance and rodent burrow density (USFWS 1985). In a study conducted in southwestern Kern County near Maricopa, BNLL population density estimates ranged from 0.47 to 0.53 BNLL per acre in "optimal" habitats and remaining habitats averaged approximately 0.16 BNLL per acre. Additionally, on a two-acre study site not subjected to oil and gas development near Taft in Kern County, BNLL density ranged from 0.1 and 0.5 BNLL per acre (USFWS 1985).

BNLL emerge from hibernation during April and May and remain active above ground through October; adult breeding activity peaks in May and June with eggs being laid in June and July; after about two months of incubation, young hatch from late July through early August and rarely into September. Adult, aboveground activity greatly decreases after June and lizards enter into hibernation into late September and early October (Garcia and Associates 2006). Aboveground activity is largely dependent on ground surface temperatures; lizards are most active on the ground when air temperatures are between 74 and 104 degrees Fahrenheit, with soil temperatures between 72 and 97 degrees Fahrenheit. Habitat disturbance, destruction and fragmentation, especially conversion to agriculture, are the greatest threats to BNLL populations (USFWS 2009).

Surveys for BNLL have been conducted since 2008 in support of former proposals of HECA. Non-protocol-level surveys were performed for BNLL during 2008 in support of the original AFC, a portion of which occurs within the currently proposed carbon dioxide pipeline route. During these surveys, a total of 25 BNLL sitings were documented during July and August 2008 surveys in the area south of the California Aqueduct within the carbon dioxide pipeline corridor (URS 2009c, URS 2012a Figure A45-1). In addition, one first-year male BNLL was observed during May 2009 near the Coles Levee Preserve and one adult BNLL was found near Magnolia Road during August and September 2010 surveys west of the proposed natural gas pipeline (URS 2009 b,c and URS 2010p). BNLL is known to occupy Elk Hills, Coles Levee Preserve, Tule Elk State Reserve, and Kern Water Bank. Given known occurrences at Tule Elk State Reserve and current CNDDB records for this area, BNLL have the potential to occur along the proposed potable water/transmission line route located immediately north of the reserve. BNLL are known to occur on the lower flanks of the EHOF, primarily the northern and southern habitat conservation areas that support low-gradient drainages with sparse saltbush scrub habitat. The carbon dioxide pipeline route occurs most closely to the North Flank monitoring route of the Elk Hills conservation areas. No BNLL were observed along the North Flank monitoring route during 2007 to 2010 monitoring years (OEHI 2012b). Following the 2011 Elk Hills monitoring year, no BNLL were observed during spring and fall road surveys along the North Flank Road route although five BNLL were observed during spring 2011 walking surveys of the North Flank route (Western Kern Environmental Consulting 2012).

Portions of the natural gas pipeline route along Highway 58 support suitable BNLL habitat (**Biological Resources Figure 2**). The applicant identified five areas along the route as potential habitat areas and conducted protocol-level BNLL surveys during 2012. Presently, no BNLL have been observed on the five sites along the natural gas pipeline route although staff has not been provided a final survey report (URS 2012a). All five locations are potential BNLL habitat, primarily Site 1 which resembles habitat quality of the nearby Buttonwillow Ecological Preserve located further west. Several observations of side-blotched (*Uta stansburiana*) and western whiptail (*Cnemidophorus tigris mundus*) were recorded at all five sites; however, more observations of these lizards were found along Site 1 than the other four sites which may indicate Site 1 provides more suitable lizard habitat than the other sites.

The processed water pipeline route itself does not provide suitable habitat for BNLL; however, the adjacent KRFCC supports allscale scrub habitat and more open areas of the KRFCC with lower shrub density may support BNLL individuals. The northern extension of the railroad spur/natural gas pipeline route do not support potential habitat given the surrounding agricultural fields on all sides. Active cultivation of row crops precludes occupancy by BNLL (USFWS 1998); therefore, the project’s alfalfa and row crop acreage is not considered potential habitat for this species. In summary, BNLL are assumed present within the carbon dioxide pipeline route and potentially present within Sites 1 through 5 along the natural gas pipeline route.

Western Spadefoot Toad (*Spea hammondii*, California Species of Concern)

Western spadefoot toads, a California species of concern, occur primarily in grassland habitats but can also be found in valley foothill woodlands and require vernal pools or other seasonally inundated wetlands for breeding. This distribution of this near endemic California species is from Redding, Shasta County southward into northwestern Baja, California and entirely west of the Sierran-desert range axis. Spadefoot toads are almost completely terrestrial and enter ponds only to breed. Spadefoot toads breed in temporary rain-filled pools with water temperatures ranging from 9 to 30 ºC that remain filled with rainwater for a minimum of 3 weeks in order to completely metamorphose (CDFG 1994). Suitable breeding pools must lack non-native species such as crayfish, bullfrogs, and introduced fishes. They occupy seasonal pools and seasonal ponds from sea level to approximately 4,100 feet elevation. Western spadefoot toads spend the majority of time burrowed below ground and only emerge above ground to breed following relatively warm (> 10.0-12.8ºC) rains in late winter-spring and fall. Spadefoot toads emerge from burrows in loose soil to a depth of at least one meter, but surface activity may occur in any month between October and April if enough rain has fallen (CDFG 1994).

There are several CNDDB records from the Lost Hills area approximately 30 miles north of the project site. One record is from 1998 on the east side of the California Aqueduct, 2.5 miles southeast of Lost Hills; one adult was found in valley saltbush scrub habitat with scattered mesquite trees. Another CNDDB record is from 2005 from the Semitropic Ridge approximately 7 miles east of Lost Hills from a seasonal pool along a dirt road. A third CNDDB record from 2005 found tadpoles and post-metamorphs from a wide muddy-bottomed section of the Kern River inundated with approximately three feet of water (CDFG 2012).

Western spadefoot tadpoles were found in a seasonal wetland depression between the Westside Canal and California Aqueduct during 2009 surveys (HEI 2009a). Staff considers this and other seasonally wet, depressional areas of the irrigation ditches, channels, and spillways that occur in the project area potential habitat for this species, including seasonally ponded areas, assuming these areas do not remain inundated long enough to support non-native bullfrogs and other tadpole predators. Additionally, the disturbed seasonal wetlands identified along Highway 58 with sufficient hydrology may represent potential habitat for western spadefoot toad.

Giant Garter Snake (*Thamnophis gigas*, Federally Threatened, California Threatened)

The giant garter snake is a large aquatic snake and is endemic to wetland habitats of the Central Valley. Extant records coincide with historic occurrences and follow large floodplain regions, freshwater marshes, and tributary streams of the Central Valley. Historically, this species is known from Butte County in the north to Buena Vista Lake in the south and was probably absent from the northern San Joaquin Valley where the floodplain of the San Joaquin River narrows. This species is presumed extant in 11 counties and Kern County is not one of the 11 counties where this species is currently presumed to occur; the largest extant occurrences include the rice fields of the Sacramento and Colusa National Wildlife Refuge in the Colusa Basin; Gilsizer Slough in the Sutter Basin; Badger Creek area of the Cosumnes River Preserve; the Badger Creek/Willow Creek area, and the American Basin. The USFWS currently identifies 13 separate populations of GGS all within isolated areas with no protected dispersal corridors between the 13 populations (USFWS 1999a). The 13 extant, isolated populations generally range from Butte County in the north to just southwest of Fresno along the Central Valley. There are four CNDDB records for this species from the nine USGS topographic quadrangles surrounding the project site near Buttonwillow, Tupman, and west of Taft where giant garter snake was observed prior to but not during a giant garter snake study by G. Hansen (CDFG 2012).

Giant garter snake populations are distributed in portions of the rice production zones on the Central Valley. The life cycle of giant garter snake coincides well with the man-altered ecosystem of rice fields and associated water conveyance system because the spring and summer flooding and fall dry-down of rice production coincides with the biological needs of this species. This species inhabits marshes, sloughs, ponds, small lakes and agricultural wetlands such as irrigation and drainage canals, rice fields, and adjacent uplands. Suitable upland refugia habitat must be located in close proximity to its summer aquatic, foraging habitat. Essential habitat components include: adequate water during the snake's active period (early spring through mid-fall) to provide prey base and cover; emergent wetland vegetation such as cattails (*Typha* sp.) and bulrush (*Scirpus* sp.) for cover and forage; upland habitat for basking, cover, and retreat sites; and adjacent uplands for cover and refuge from floodwaters (USFWS 1999a).

San Joaquin Kit Fox (*Vulpes macrotis mutica*, Federally Endangered, California Threatened)

The San Joaquin kit fox, a federally endangered and state threatened species, is primarily nocturnal, but are commonly seen during the day in late spring and early summer (Orloff et al. 1986). Generally, kit fox are small, slim-bodied foxes with a long, bushy, black-tipped tail and large ears (USFWS 1998). This species typically occurs in valley and foothill grassland, or mixed shrub/grassland habitats throughout low, rolling hills and valleys often times utilizing habitats that have been altered by humans (e.g., agricultural land, oil fields, etc). San Joaquin kit foxes can inhabit the margins and fallow lands near irrigated row crops, orchards, and vineyards, and may forage occasionally within these agricultural areas (Cypher et al 2007). Another study found that San Joaquin kit foxes in an agricultural setting typically denned in small patches of grassland but that 40 to 50 percent of their nocturnal locations were in row crops or orchards. Kit fox often enlarge ground squirrel burrows for use as a den and may use vacant badger dens for shelter (USFWS 1998), both of which occur within the project area. Kit fox change dens frequently, sometimes only using a den for two or three days. Bjurlin (2004) estimates home range sizes vary from 1.66 square miles (1,063 acres) to 4.48 square miles (2,867 acres) making it difficult to estimate the minimum amount of habitat space or land necessary to support a small population.

The historic distribution of San Joaquin kit fox covered most of the San Joaquin Valley. Current research data and sightings indicate that the San Joaquin kit fox currently inhabit various areas of suitable habitat on the San Joaquin Valley floor and in the surrounding foothills of the Coastal Range, Sierra Nevada, Tehachapi Mountains, from southern Kern County north to Contra Costa, Alameda, and in San Joaquin counties on the west and Stanislaus County on the east. The largest extant population of kit fox occur from Elk Hills and Buena Vista Valley in western Kern County and the Carrizo Plain Natural Area in San Luis Obispo County (USFWS 1998).

While the effects of roadways on San Joaquin kit fox have not been directly studied, the relatively large space requirements, home range, high mobility, and crepuscular (active primarily at dawn and dusk) behavior of this species makes road crossings necessary throughout much of their current range (Bjurlin 2004). Loss and conversion of natural lands into agricultural, industrial, and urban development and associated practices continue to decrease available habitat. Other identified threats include habitat degradation from increased noises, noxious gases, and release of wastewater; traffic mortality; pesticides and rodenticides; competition and predation by non-native foxes; and to a lesser extent, disease (USFWS 1998).

The Recovery Plan states that a sound, conservative strategy for this species hinges on the enhanced protection and management of three geographically distinct core populations. Within the core population areas, several smaller satellite populations occur. The three core populations for San Joaquin kit fox conservation and recovery are 1) the Carrizo Plain Natural Area in San Luis Obispo County, 2) the natural lands of western Kern County (i.e. Elk Hills, Buena Vista Hill and Valley, Lokern Natural Area, and adjacent land) inhabited by kit fox, and 3) the Ciervo-Panoche Natural Area of western Fresno and eastern San Benito counties. HECA is proposed in a core population area for San Joaquin kit fox, natural lands of western Kern County including areas which support critical connection points between satellite populations. The Recovery Plan states that the Carrizo Plain and western Kern County San Joaquin kit fox populations are important for kit fox recovery and preliminary population viability analyses indicate that the possibility of the extinction of this species dramatically increase if either the Carrizo Plain or western Kern County populations are eliminated (USFWS 1998).

Due to the project occurring in a San Joaquin kit fox core recovery area and diverse habitat use of this species ranging from natural, allscale scrub to farmed agricultural lands, staff considers all habitat types in the project area suitable habitat for San Joaquin kit fox. Potential kit fox dens have been found along the natural gas pipeline route along Highway 58 and northward as well as the potable water/transmission line route. These potential dens have either shown active burrowing owl sign and/or kit fox sign which both species are known to occupy the same type of burrow; therefore all known or potential burrowing owl burrows are also potential kit fox dens. Approximately ten potential kit fox dens were found at Site 1 along the natural gas pipeline route during 2012 field surveys, none of which showed any current kit fox use. Few potential kit fox dens or burrowing owl burrows were found at Site 2 which also support California ground squirrels (*Spermophilus beecheyi*). Sites 3, 4, and 5 also support potential kit fox or burrowing owl burrows during 2012 field surveys (URS 2012c). Since San Joaquin kit fox is known to occupy the Kern Water Bank and Tule Elk State Reserve, the potential for fox to utilize habitats within the project areaand potable water/transmission line route is likely. San Joaquin kit fox are also known to occur along the California Aqueduct and other irrigation canals and adjacent uplands and agricultural areas; therefore this species is likely to occur along the processed water line. San Joaquin kit fox is known to occur on Elk Hills and along the carbon dioxide pipeline route. Field surveys were conducted during February 2011 along the proposed route and several large mammal dens (coyote, American badger, kit fox) were observed although did not show sign of active occupancy (HECA 2012b, Volume 2 Appendix A); follow-up surveys performed along the proposed carbon dioxide pipeline route in 2012 identified two potential kit fox dens (OEHI 2013b). No active natal kit fox dens were identified following 2011 monitoring of the Elk Hills Conservation Areas (Western Kern Environmental Consulting 2012); however, active natal kit fox dens were observed along the north flank Elk Hills area, west of the proposed carbon dioxide pipeline route from 2007 to 2010 monitoring of the Elk Hills Conservation Areas (OEHI 2012b).

San Joaquin Antelope Squirrel (*Ammospermophilus nelsoni*, California Threatened)

San Joaquin antelope squirrel occur in valley saltbush scrub habitats ranging in elevation from approximately 160 feet on the San Joaquin Valley floor side to approximately 3,600 feet in the Temblor Range. This species' range is unevenly distributed and only occurs in a few localities, including the Lokern and Elk Hills region of western Kern County as well as the Carrizo and Elkhorn Plains in eastern San Luis Obispo County (Garcia and Associates 2006). Over 80 percent of their original geographic range had been converted to agriculture by 1979 with relatively no prime, undisturbed habitat remaining within the San Joaquin Valley for this species.

In the southern and western San Joaquin Valley, this species is associated with arid, open gently sloping grasslands with scattered shrubs in areas free of flooding. This species requires loose, friable soils for digging their own burrows; otherwise they will often co-occur and utilize burrows of giant kangaroo rats where soils are otherwise too coarse for San Joaquin antelope squirrel to burrow laterally into banks. In areas with sparse shrub cover, this species commonly co-occurs with giant kangaroo rats; the distribution of Nelson's antelope squirrel and abundance appears to be positively related to low rainfall, loose soil texture, shrub cover, and presence of giant kangaroo rats (Garcia and Associates 2006).

Several San Joaquin antelope squirrels were observed during 2009 biological field surveys near the Town of Tupman and Elk Hills area performed for previous versions of the HECA project (HEI 2009a, URS 2009b). Focused surveys and small mammal trapping have not been conducted for this species in the project area; surveys for this species for the current linear alignments were completed in conjunction with 2012 wetland delineation, botanical, Swainson's hawk, and blunt-nosed leopard lizard surveys during which no San Joaquin antelope squirrel were observed (URS 2012a). This species is assumed present in allscale scrub habitats east and west of the California Aqueduct. San Joaquin antelope squirrel was not captured following 2011 monitoring of the Elk Hills conservation areas (Western Kern Environmental Consulting 2012); the last time this species was trapped on Elk Hills was during the 2008 monitoring year. This species is known to occur at Kern Water Bank, Tule Elk State Reserve, and several CNDDB records occur for this species east of the California Aqueduct. Since this species is known to occur in the project area, all scrub habitat in the project area is considered potential habitat for San Joaquin antelope squirrel.

Tipton Kangaroo Rat **(*Dipodomys nitratoides nitratoides,* Federally Endangered, California Endangered)** ***and Short-nosed Kangaroo Rat*** **(*Dipodomys nitratoides brevinasus,* California Species of Concern)**

The Tipton kangaroo rat (*Dipodomys nitratoides nitratoides)* is one of three subspecies of San Joaquin kangaroo rat (*D. nitratoides*) and is restricted to the Tulare sub-basin. Within *D. nitratoides*, individuals from the western edge of the San Joaquin Valley and west of the California Aqueduct are genetically distinct as short-nosed kangaroo rats (*D. nitratoides brevinasus*) based on morphology, chromosome number, and habitat preference. The short-nosed kangaroo rat is a California species of concern and a Bureau of Land Management Sensitive species. Construction of flood control and water diversion structures removed some of the genetic barriers, a narrow zone of seasonal and permanent wetlands around Kern and Buena Vista lakes, and probably allowed for genetic exchange between short-nosed and Tipton kangaroo rat subspecies; however, today the California Aqueduct and large expanses of irrigated farmlands have genetically isolated these populations (USFWS 1998). Tipton kangaroo rat mostly occurs east of the California Aqueduct and occupies scrub and grassland communities near level terrain with the alluvial floodplain soils. Important natural communities for Tipton kangaroo rat are iodine bush shrubland and valley saltbush scrub. In areas subject to occasional flooding, Tipton kangaroo rat will construct burrows on elevated ground (Garcia and Associates 2006). Sparse to moderate shrub cover in terraced grasslands typically supports higher densities of this species, although burrow systems are often situated in more open habitats. Terrain not subject to permanent flooding is essential for permanent occupancy by this species (USFWS 1998).

Focused surveys and small mammal trapping were not performed for this species; however, this species is assumed present within portions of the project east of the California Aqueduct. Tipton kangaroo rat is known to occur in the Coles Levee Ecosystem Preserve, Kern Water Bank, and likely the Tule Elk State Reserve. This species is assumed present east of the California Aqueduct within saltbush scrub or alkali sink scrub habitats, although there are CNDDB records of this species west of the California Aqueduct as well. Tipton kangaroo rat does not occur on Elk Hills since short-nosed kangaroo is the genetically distinct subspecies known to occur on Elk Hills. Following 2011 monitoring of the Elk Hills conservation areas, short-nosed kangaroo rat was the most commonly trapped small mammal on trap gridlines (Western Kern Environmental Consulting 2012). All allscale scrub habitats associated with linear facility routes east of the California Aqueduct are suitable habitat for Tipton kangaroo rat.

Giant Kangaroo Rat **(*Dipodomys ingens*, Federally Endangered, California Endangered)**

Up until the 1950s, colonies of giant kangaroo rats were spread over hundreds of thousands of acres of gently rolling, continuous grasslands habitat along the western edge of the San Joaquin Valley, Carrizo Plain, and Cuyama Valley. Presently, this species is known from six major geographic sub-units including the Panoche region in western Fresno and eastern San Benito counties; Kettleman Hills in Kings County; San Juan Creek and Carrizo Plain in San Luis Obispo County; the Elk Hills, Taft, Maricopa, McKittrick, and other upland areas in western Kern County; and Cuyama Valley in

Santa Barbara and San Luis Obispo counties. Giant kangaroo rats occupy both grassland and low-density shrub communities in a variety of soil types and on slopes up to approximately 2,800 feet above mean sea level yet preferred habitats of this species are annual grassland communities of less than 10 percent slope with friable, sandy loam soils (USFWS 1998). In lower elevation areas (less than 1,300 feet) in the southern San Joaquin Valley, giant kangaroo rats occupy annual grasslands and alkali scrub and saltbush communities with an herbaceous community of red brome, red-stemmed filaree, and annual fescue. Several studies indicate that this species prefers flat terrain with low shrub cover; one study indicated that this species selected sites with dense grass cover and low shrub cover in disturbed areas more times than bare areas or areas with dense shrub cover and that giant kangaroo rats spent little to no time under shrubs (Harris et al 1987). In the southern San Joaquin Valley, giant kangaroo rats are primarily known to occur on the south or west side of the California Aqueduct although a recent discovery of a giant kangaroo rat was found during small mammal trapping for the Buena Vista Water Storage Pipeline on the east side of the California Aqueduct which suggests this species does occur east of the aqueduct (CDFW, pers comm. October 2012). This discovery was between the California Aqueduct and Kern Water Flood Control Channel in the vicinity of the processed water pipeline and west of HECA.

Giant kangaroo rats are active all year and do not become dormant during certain seasons or weather patterns. This species is primarily nocturnal although has been observed during daylight hours during hot summer temperatures. The greatest value of the former Naval Petroleum Reserves (formerly known as NPR-1 and NPR-2) in California to giant kangaroo rats is the large extent of habitat of varying quality and its connectivity to adjacent habitat in the Lokern area (USFWS 1998). Giant kangaroo rats are granivores (seed-eaters) and cut the ripening heads off of grasses and forbs and gather individual seed heads and store them in small, above-ground surface pits over their burrow systems, called precincts, which is then covered by loose debris and dirt. Precincts (individual territories in which 2 to 1,000 precincts can signify a territory) are specific to the species and mapping precincts can allow for the identification of specific sign and presence of the species in areas where they are expected to occur.

Concerning the recent discovery of giant kangaroo rat during small mammal trapping for the Buena Vista Water Storage Pipeline on the east side of the California Aqueduct, a precinct was not present which further supports the notion that the absence of precincts does not preclude the presence of giant kangaroo rat. Estimated home ranges can range in size from 60 to 350 square meters and the core area of the territory is located over the precinct. A single individual or several individuals of females and offspring may occupy precincts. Burrows are typically located on flat to gently sloping terrain and areas preferred for permanent colonies of this species include areas not subject to seasonal flooding. In areas of suitable habitat and soil burrowing conditions, populations may exceed 20 individuals per acre (USFWS 1998).

This species was not targeted during surveys and small mammal trapping was not conducted; however, this species is known to occur in high population numbers along the eastern flank of Elk Hills. In support of a former carbon dioxide pipeline route, the applicant conducted a walking survey of the carbon dioxide pipeline route and a 1,000-foot buffer during April 2010 for giant kangaroo precincts and none were found within the survey that included southern sections 16, 21, and 28 within Township 30, Range 24 (URS 2010k) of the *East Elk Hills* topographic quadrangle map. Following the 2007, 2009, and 2011 monitoring years, giant kangaroo rat precincts were identified in Elk Hills Section 22S and in the immediate vicinity of the carbon dioxide pipeline route (OEHI 2012b) among other areas of the Elk Hills Conservation Area. Following the 2010 monitoring survey season, a total of 1,946 active precincts were identified in 2011, which represents a 142 percent increase from the 805 active precincts reported the previous year of Elk Hills Conservation Areas (Western Kern Environmental Consulting 2012). Following 2012 field surveys, four giant kangaroo rat precincts were identified within 50 feet of the proposed carbon dioxide pipeline route (OEHI 2013b). Given the known high population numbers from Elk Hills of giant kangaroo rat and their precincts, staff considers the entire eastern flank of Elk Hills and carbon dioxide pipeline route occupied habitat of this species. Due to recent discoveries of this species east of the California Aqueduct in the immediate project area, staff also considers allscalle scrub and intermixed disturbed grassland communities within the project area and linear facilities potential habitat for this species.

***Buena Vista Lake Shrew* (*Sorex ornatus relictus*, Federally Endangered, California Species of Concern)**

Buena Vista Lake shrew is one of nine subspecies of the ornate shrew, *Sorex ornatus*. Historically, this shrew occurred in wetlands and sloughs around the Buena Vista Lake and Goose Lake beds and presumably throughout the Tulare Basin other historic Tulare Lake Bed. This species historically inhabited mesic habitats associated with the Tulare Sub-basin including wet meadows, riparian corridors, freshwater marshes, and alkali sink scrubs. This species inhabits densely vegetated areas around the margins of marshes, lakes, and sloughs although little is understood about the current range of Buena Vista Lake shrew and a few extant populations are know from the Tulare Basin and the Buena Vista Lake slough area further south of the project site.

Live small mammal trapping that was conducted at six sites within the Tulare Basin during 1999 and 2000, resulted in nine Buena Vista Lake shrews collected at the Coles Levee Preserve, one of the six trapping sites, among others trapped at the Kern Fan Recharge Area and the Kern National Wildlife Refuge (Garcia and Associates 2006). The USFWS designated final critical habitat for this species on January 24, 2005 (USFWS 2005). The Kern Lake Preserve Unit, totaling approximately 84 acres, was designated as final critical habitat for this species. Presently, critical habitat is proposed for Buena Vista Lake shrew south of the Tule Elk State Reserve at the confluence with the Cross Valley Canal. The nearest CNDDB record is a historic record from 1969 near Tejon Creek in the Tejon Hills, approximately four miles south of the project site. This species is known to occur on Coles Levee Ecosystem Preserve.

This species was not observed during field surveys although small mammal trapping has not been conducted which is the only definitive method for determining presence or absence in the project area. There is a low potential for Buena Vista Lake shrew to occur in wet areas along the West Side Canal and East Side Canal during years with adequate rainfall and adequate vegetative cover. Although this species generally has a low potential to occur in the project area, the greatest potential for occurrence of Buena

Vista Lake shrew is along the project's proposed processed water pipeline and railroad spur.

Western Burrowing Owl **(*Athene cunicularia*, California Species of Concern)**

Western burrowing owls are a California Species of Concern and yearlong resident in suitable habitats throughout California, although some populations undergo local movements. In California, burrowing owls range from the Central Valley extending from Redding to the Grapevine area in the Central Valley; east through the Mojave Desert and west to San Jose, San Francisco Bay area, and the outer coastal foothill area from Monterey south to San Diego; and the Sonoran Desert. Agricultural areas and canal systems provide important burrowing habitat for this species. Grasslands and desert shrub stepped habitats are considered naturally occurring habitats of this species, while burrowing owls may also occur in agricultural or grassy areas, or vacant lots and pastures, if the vegetation is low and suitable forage and burrowing sites are available nearby (CDFG 2012b). In recent years, their numbers have drastically declined in southern California and remnant populations persist in isolated agricultural areas and grasslands, particularly in the high desert in the Chino Hills/Prado Basin, rural areas of San Bernardino, Riverside, and San Diego counties. However, they are still fairly common in and around agricultural areas of the Imperial Valley (Small 1994).

Burrowing owls are unique among the North American owls in that they nest and roost in burrows, especially those created by California ground squirrels (*Spermophilus beecheyi*), kit fox (*Vulpes macrotis*), desert tortoise (*Gopherus agassizii*), and other wildlife as well as man-made structures such as culverts, exposed pipes, and debris piles as artificial burrows. Their home range is distinctly tied to the location of their burrow system and there are differences in their diurnal and nocturnal home ranges. The best available scientific data indicates that foraging occurs primarily within a 600 meter radius (estimated 300 acres) of the nest burrow during the breeding season (CDFG 2012b). Diurnal home range for owls can be 150 feet on both sides of burrow; the nocturnal home range is typically much larger, one square mile per owl pair, and several owls can overlap in that one square mile (Pers. Comm. Peter Bloom). The mean home range for 11 male burrowing owls in 1998 and 22 males in 1999 was 177 ha (437 acres) and 189 hectares (467 acres), respectively, at naval Air Station in Lemoore, California which is located south of Fresno (Bloom 2003). Male burrowing owls often move greater than 1,000 meters when foraging during the breeding season (Bloom 2003). Intra-specific aggressive displays for defending breeding territories can occur and breeding territories can range from 250 to 600 meters (500 feet to 1,970 feet).

The availability of burrows is an essential component of burrowing owl habitat since the burrows provide protection, shelter, and nest sites. Essential habitat for burrowing owls in California includes suitable year-round habitat for breeding, foraging, wintering, and dispersal of owls consisting of shore or sparse vegetation, presence of suitable burrows, or fossorial mammals, and availability of abundant prey within close proximity to the burrow system (CDFG 2012b). Burrowing owls have a strong affinity for previously occupied nesting and wintering habitats. They often return to burrows or at least the same burrow area used in previous years to nest, especially if they were successful at reproducing there in previous years (Gervais *et al.* 2008, CDFG 2012b). Burrowing owls are known to use satellite burrows which typically occur within 75 meters of the nest burrow and owl pairs use on average approximately five satellite burrows (CDFG 2012b). The southern California breeding season (defined as from pair bonding to fledging) generally occurs from February to August with peak breeding activity from April through July (Haug et al. 1993).

Burrowing owls were detected along the formerly proposed carbon dioxide pipeline and natural gas linear during August 2008 and August 2010 surveys, respectively (URS 2010o). During 2011 field surveys, burrowing owls were observed immediately south of the potable water/transmission line route; during these surveys which coincided with the burrowing owl nesting season, three individual adult owls were observed, including a pair of adults with no young observed along Morris Road (HECA 2012a).

Following 2012 field surveys, burrowing owls and several potential burrows were also observed at Site 1 along the natural gas linear where two individual owls were found during May through July BNLL surveys. Burrowing owl sign was also found during BNLL surveys at sites 2 and 3 along the natural gas route. A known burrowing owl pair with successful breeding was documented during 2012 from the Buttonwillow Ecological Reserve along Brandt Road, approximately 0.50 mile west of the proposed natural gas linear route (URS 2012a). This species is known to occur at Kern Water Bank, Tule Elk State Reserve, Elk Hills, and the Buttonwillow Ecological Reserve. During 2011 monitoring year of Elk Hills Conservation Areas, burrowing owls were observed throughout spring and fall kit fox and BNLL surveys; during pre-activity surveys, four owls and 24 owl burrows were found, of which 7 burrows were active (Western Kern Environmental Consulting 2012). In addition, two burrowing owls were observed along the carbon dioxide pipeline route following 2012 field surveys (OEHI 2013b). Suitable habitat occurs within the project area for this species, primarily within the allscale scrub habitat of the project's linear facilities.

***Swainson's Hawk* (*Buteo swainsoni*, Caifornia Threatened)**

Swainson's hawks, a state threatened species, require large areas of open landscape for foraging, including grasslands and agricultural lands that provide low-growing vegetation for hunting and high rodent prey populations. This species has suffered a decline in the Central Valley as with other North American raptor populations, largely due to the conversion of native communities to agricultural lands, the southern San Joaquin Valley in particular which is devoid of suitable nest trees and well-developed riparian areas due to agricultural conversion. Swainson's hawks typically nest in large native trees such as valley oak (*Quercus lobata*), cottonwood (*Populus fremontii*), walnut (*Juglans hindsii*), and willow (*Salix* spp.), and occasionally in non-native trees, such as eucalyptus (*Eucalyptus* spp.) within riparian woodlands, roadside trees, trees along field borders, isolated trees, small groves, and on the edges of remnant oak woodlands (CDFG 1993). The present-day agriculture in the southern San Joaquin Valley, primarily cotton and vineyards, are not compatible with Swainson's hawk hunting style (Estep 1989).

Two populations comprise the current Swainson's hawk range in California: northeastern counties of Modoc, Siskiyou, and Lassen of upland juniper-sage/steppe communities, and the more isolate Central Valley population in intensively farmed agricultural regions of the Sacramento and San Joaquin valleys (Estep 1989). A study of four study sites located between Sacramento and Stockton in the Central Valley to investigate home ranges, foraging behavior, use of agricultural fields, and nest site selection, showed the foraging ranges of some radio-tagged Swainson's hawks had an elastic pattern and fluctuated with the pattern of crop maturity and harvest. Results showed evidence that as some crop types mature, vegetative cover increases which reduced prey availability and causes Swainson's hawks to spend less time foraging over mature, non-harvested crop fields. Unless farming activities attracted hunting Swainson's hawks, birds only spent a few minutes foraging over a field before moving on; this highly active foraging behavior often resulted in birds traveling as far as 18 miles from the nest in search of prey. Swainson's hawks responded, however, to the abundance of prey that became available during harvest. During typical crop harvest times of year (generally late July through September), daily foraging ranges were as small as 30 acres and Swainson's hawks often restricted hunting activities to a single field (Estep 1989).

In this study, of the 30 cover types that occurred in the project area discussed above, Swainson's hawks were observed using 17 cover types. Cover types that had less overall vegetative cover and greater prey availability ranked the highest (alfalfa, disced fields, fallow, and dryland pasture). Alfalfa was preferred across all 12 hawks that were radio-tagged and the foraging use of alfalfa occurred continuously from March through September. The alfalfa fields that occurred in the project area were mowed and bailed once a month generally, keeping its vegetative cover less than that of maturing row and grain crops. Unlike row and grain crops that are harvested and replanted annually, a single alfalfa planting may remain and continue to produce hay in a particular field for up to six years in the Central Valley (Estep 1989). While beet and tomato fields supported the largest prey populations, dense cover appeared to preclude hawk foraging during most of the year; however, during harvest these crop types were hunted regularly. Swainson's hawk used tomato and beet fields for foraging a high percentage of time, primarily due to a high frequency of harvesting. In some cases, in large fields of beets and tomatoes being harvested, Swainson's hawks would feed in groups and would remain for the length of the harvest and up to several days. Other row crops such as corn, sunflowers, safflower, beans, and peppers were less preferred since these crops create an impenetrable barrier for hunting Swainson's hawks during maturity. Dryland pastures, the land cover type that most resembles the physical characteristics of historic grassland habitat in the Central Valley, were also frequented often by hunting hawks usually in response to farming activities (Estep 1989).

The applicant performed protocol-level surveys for Swainson's hawk nesting activity during 2010, 2011, and 2012. The survey area included a five-mile radius around the project site, a one-mile radius to the northeast to cover more agricultural areas, and a half-mile radius into the Elk Hills region. Staff and CDFW agreed that although this survey buffer area strays from the survey protocol (Swainson's Hawk Technical Advisory Committee 2000), the modified survey area was adequate to allow for the identification of nesting pairs that have the potential to be impacted by construction within the project area. Potential Swainson's hawk nest trees were considered all living trees of approximately 20 feet and taller. All trees meeting this criterion were recorded by species and the presence of farmhouses, homesteads, agricultural areas, and developed areas were also noted. Several tree units representing possibly hundreds of suitable raptor nests trees were identified within the survey area. During 2012 focused surveys for nesting Swainson's hawks, 19 active raptor nests were identified in the survey area described above, six of which were Swainson's hawk nests and four of which were confirmed to have successfully fledged young. The remaining 13 active nests were either common raven, great-horned owl, red-tailed hawk, or red-shouldered hawk nests (URS 2012a).

The project area supports approximately 203 acres of alfalfa and 368 acres of other row crops. The five most common crop types in the project area are alfalfa, cotton, pistachio, wheat, and dry onion (HECA 2012b, Land Use Table 5.4-3). Staff considers the 203 acres of alfalfa as suitable foraging habitat for this species and depending on the frequency of farming and crop rotation of the other low-growing rowcrops such as cotton and dry onion, these fields may support an adequate prey base for Swainson's hawk, which increases the foraging habitat value for this species.

Golden Eagle (*Aquila chrysaetos*, California Fully Protected)

Golden eagles are typically year-round residents found throughout most of their western United States range. They breed from late January through August with peak activity from March through July (Kochert et al. 2002). Migratory patterns are fairly local in California where adults are relatively sedentary, but dispersing juveniles sometimes migrate south in the fall. This species is considered to be more common in southern California than in the northern part of the state (USFS 2008). Habitats for this species typically include rolling foothills, mountain areas, and deserts. Golden eagles need open terrain for hunting and prefer grasslands, deserts, savanna, and early successional stages of forest and shrub habitats. Golden eagles primarily prey on lagomorphs and rodents but will also take other mammals, birds, reptiles, and some carrion (Kochert et al. 2002). This species prefers to nest in rugged, open habitats with canyons and escarpments, with overhanging ledges and cliffs and large trees used as cover.

The status of golden eagle populations in the United States is not well known, although there are indications that populations may be in decline (USFWS 2009b, Kochert et al. 2002). Accidental death from collision with manmade structures, electrocution, gunshot, and poisoning are the leading causes of mortality for this species, and loss and degradation of habitat from agriculture, development, and wildfire continues to put pressure on golden eagle populations (Kochert et al. 2002; USFWS 2009b).

Absent interference from humans, golden eagle breeding density is determined by either prey density or nest site availability, depending upon which is more limiting (USFWS 2009b). A compilation in Kochert et al (2002) of breeding season home ranges from several western United States studies showed an average home range of 20 to 33 square kilometers (7.7 to 12.7 square miles). In San Diego, a study of 27 nesting pairs found breeding ranges to be an average of 36 square miles with a range from 19 to 59 square miles (Dixon 1937). Other studies from within and outside the United States include ranges from nine to 74.2 square miles (McGahan 1968; Watson et al. 1992 [range of 14.7 to 26.1 pairs per 1,000 square kilometers]). An Environmental Assessment (EA) and Implementation Guidance for take permits have been issued under the Bald Eagle and Golden Eagle Protection Act (USFWS 2009c). The EA specifies that in implementing the resource recovery permit for take of inactive golden eagle nests (50 CFR 22.25), data within a 10-mile radius of the nest provides adequate information to evaluate potential effects.

There are three CNDDB records for golden eagles nests for the entire County of Kern, although this species is rarely reported in the CNDDB due to sensitivity of nest locations: one record is from 1995 along the south fork of oil canyon creek, approximately 16 miles north of Mojave in foothill/pinyon pine woodland; a second record is from 1991 in Sequoia National Forest, 0.5 mile north of Cottonwood Creek from Jeffrey pine and white fir habitat; and a third nest location from Red Rock Canyon State Park during 1988 (CDFG 2012). There are no known golden eagle nest sites within 30 miles of the project area. Golden eagles have been reported in the project area, but mostly as transients. At least five golden eagles were observed on the edge of Elk Hills approximately five years ago and a deceased female golden eagle hit by a vehicle was picked up on the western side of the Tule Elk State Reserve during October 2010; other reports from local birding experts indicate golden eagles are commonly observed in eastern Kern County and have been observed in western Kern County as transients (URS 2012a). Since there are no known nest sites in the immediate project vicinity and high agricultural use of the project area, golden eagles are not expected to utilize the site's agricultural fields for forage and likely only occur as transients during migration.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHODS AND THRESHOLD FOR DETERMINING SIGNIFICANCE

The determination of whether a project has a significant effect on biological resources is based on the best scientific and factual data that staff could review for the project. CEQA requires a list of criteria that are used to determine the significance of identified impacts. A significant impact is defined by CEQA as "a substantial, or potentially substantial, adverse change in any of the physical conditions within the area affected by the project" (CEQA Guidelines Section 15382).

Thresholds for determining CEQA significance in this section are based on Appendix G of the CEQA Guidelines (CCR 2012) and performance standards or thresholds identified by staff. In this analysis, the following impacts to biological resources are considered significant if the project would:

- Have a substantial adverse effect, either directly or through habitat modifications, on any species identified as a candidate, sensitive, or special-status species in local or regional plans, policies, or regulations, or by the CDFW or USFWS;
- Have a substantial adverse effect on any riparian habitat or other sensitive natural community identified in local or regional plans, policies, or regulations, or by the CDFW or USFWS;
- Have a substantial adverse effect on federally protected wetlands as defined by Section 404 of the Clean Water Act (including, but not limited to marsh, vernal pool, coastal, etc.) through direct removal, filling, hydrological interruption, or other means;

- Interfere substantially with the movement of any native resident or migratory fish or wildlife species or with established native resident or migratory wildlife corridors, or impede the use of native wildlife nursery sites;
- Conflict with any local policies or ordinances protecting biological resources, such as a tree preservation policy or ordinance;
- Conflict with the provisions of an adopted Habitat Conservation Plan, Natural Community Conservation Plan, or other approved local, regional, or state habitat conservation plan;
- Conflict with applicable federal, state, or local laws, ordinances, regulations, and standards (LORS) protecting biological resources, as listed in **Biological Resources Table 1**; and
- Have a substantial adverse effect on any other species receiving consideration during environmental review under CEQA Section 15830, including species not protected through state or federal listing but nonetheless demonstrable as "endangered" or "rare" under CEQA.

The CEQA Guidelines define "direct" impacts as those impacts that result from the project and occur at the same time and place. "Indirect" impacts are defined as those that are caused by the project, but can occur later in time or farther removed in distance while still reasonably foreseeable and related to the project. The significance of impacts is generally determined by compliance with applicable LORS; however, guidelines adopted by resource agencies may also be used. Staff has also evaluated the potential for cumulative effects of the project on biological resources when considered with all past, currently proposed, and future projects in the region.

Impact analyses typically characterize effects to plant communities as temporary or permanent, with a permanent impact referring to areas that are paved or otherwise precluded from restoration to a pre-project state. For the purpose of this analysis, an impact is considered temporary if there is evidence to indicate that pre-disturbance levels of biomass, cover, density, community structure, and soil characteristics could be achieved within five years through revegetation activities.

Biological Resources Table 5 summarizes the acreages of direct habitat loss for special-status wildlife species which would require compensatory habitat mitigation outlined in staff's proposed Condition of Certification **BIO-20**. Once the applicant submits a comprehensive mitigation plan for the project and based on further coordination with staff, CDFW, and USFWS, these acreages may change in preparation of the FSA/FEIS. This section analyzes the potential for direct and indirect impacts of construction and operation of HECA to biological resources and provides suggested mitigation measures to reduce the severity of potentially adverse impacts as summarized in **Biological Resources Table 6.**

Biological Resources Table 5
Direct Habitat Impact Acreages for Upland Wildlife Species

Vegetation Community/Cover Type in project area (Total Direct Habitat Impact for Project)	San Joaquin kit fox	Giant kangaroo rat	Tipton kangaroo rat	San Joaquin antelope squirrel	Burrowing owl	Blunt-nosed leopard lizard	Swainson's hawk
Allscale scrub/natural vegetation (**32.7 acres**)	32.7	32.7	32.7	32.7	32.7	32.7	0
Alfalfa (**203.34** acres)	203.34	0	0	0	0	0	203.34
Other row crops (**368.43**)	368.43	0	0	0	0	0	368.43
Orchards (**8.91**)	8.91	0	0	0	0	0	0
Developed/disturbed (**159.75**)	159.75	159.75	159.75	159.75	159.75	159.75	0
Total	**773.13**	**192.45**	**192.45**	**192.45**	**192.45**	**192.45**	**571.77**

Biological Resources Table 6
Summary of Impact/Proposed Mitigation

Biological Resource	Impact/Proposed Mitigation
Vegetation Communities & Associated Wildlife	**Direct impacts:** Permanent and temporary loss of 30 acres of allscale scrub/non-native grassland habitat and loss of approximately 580 acres of alfalfa, orchards, and other row crops which provide habitat for a number of plants and wildlife (**Biological Resources Tables 7,8**). **Indirect impacts:** Disturbance (noise, lights, dust) to surrounding plant and wildlife communities; spread of non-native invasive weeds and disruption of plant community composition; changes in drainage patterns; erosion and sedimentation of disturbed soils. **Mitigation:** Impact avoidance and minimization measures, worker awareness and education training, species-specific preconstruction clearance surveys, biological monitoring, and reporting outlined in **BIO-1** through **BIO-18**. Staff has outlined a compensatory habitat mitigation strategy for listed species in **BIO-20**.
Sensitive Vegetation Communities	**Direct impacts:** None anticipated. **Indirect impacts:** Valley sink scrub and small, patchy riparian habitat occurs north of the proposed well field along the processed water pipeline. If these communities are supported by shallow groundwater or other sub-surface water flows through adjacent irrigation canals, groundwater pumping for the project at the proposed BVWSD well field could cause a gradual decline of riparian nest trees and sensitive vegetation communities such as valley sink scrub and more analysis is required. **Mitigation:** Additional information needed on the water supply and water use of valley sink scrub and riparian habitats in the project area; staff has not proposed mitigation until further analysis has been performed.

Biological Resource	Impact/Proposed Mitigation
Potential waters of the State and Waters of the United States	**Direct impacts:** The extent of Corps jurisdiction over potential Waters of the U.S. identified in the site are unknown at this time; the occurrence of and impacts to potential state waters within the project area and ephemeral drainages along the carbon dioxide route are unknown at this time. CDFW has indicated that proposed HDD (HDD) activities under water conveyance features would require the applicant submit a Notification of a Streambed Alternation Agreement describing the proposed work and the applicant submitted this application during May 2013 (URS 2013d). **Indirect impacts**: Potential for frac-out (escape of drilling mud to the water surface as a result of a spill or tunnel collapse) from HDD and indirect effects to water quality and contamination during construction of the project. **Mitigation:** Implementation of **SOIL& SURFACE WATER – 1** (Drainage, Erosion Sedimentation Control Plan), and **BIO-19** (state waters) including the requirement to prepare a Horizontal Directional Drilling Plan would minimize the potential for indirect impacts to potentially jurisdictional state waters and waters of the U.S. including drainages and irrigation canals; however, a determination of the extent of Corps and CDFW Section 1600 jurisdiction over the project is unknown at this time.
Special-status plant species: • Hoover's eriastrum (CNPS List 4.2) • Gypsum-loving larkspur (CNPS List 4.2) • Lost Hills crownscale (CNPS List 1B.2) • Oil nest straw (CNPS List 1B.1) • San Joaquin bluecurls (CNPS List 4.2) • Cottony buckwheat (CNPS List 4.2) • Vernal barley (CNPS List 3.2)	**Direct Impacts:** Loss of individual plants (Hoover's eriastrum, oil nest straw and possibly others) during site grading along carbon dioxide pipeline route. Potential loss of populations of vernal barley along the natural gas pipeline route. Permanent and temporary loss of allscale scrub habitat. Loss of exact number of individuals is unknown since the mapping of rare plant occurrences has not been provided to staff. **Indirect impacts:** Introduction and spread of invasive plants; erosion and sedimentation of disturbed soils; alteration of drainage patterns; herbicide drift; disruption of photosynthesis and other processes from dust. **Mitigation:** Implementation of **BIO-17** requires the applicant to conduct focused preconstruction surveys for additional special-status plant occurrences in suitable habitat areas, including mapping and avoidance of populations as Environmentally Sensitive Areas. Additional focused botanical surveys, field data collection, and GPS mapping are needed along the carbon dioxide and natural gas pipeline routes (primarily Sites 1 through 5) following *Protocols for Surveying and Evaluating Impacts to Special Status Native Plant Populations and Natural Communities* (CDFG 2009).

Biological Resource	Impact/Proposed Mitigation
San Joaquin kit fox and American badger	**Direct impacts:** Loss of approximately 773 acres of allscale scrub/disturbed non-native grasslands and agricultural lands (**Biological Resources Table 5**) that provide foraging, denning, and dispersal values and promote movement opportunities and genetic exchange for San Joaquin kit fox between the Western Kern Core Recovery Area and adjacent satellite population in urban Bakersfield and Semitropic satellites farther north and east; fragmentation and degradation of habitat; increased risk of traffic collision and vehicle strikes from construction and operation traffic; crushing or entombing animals in burrows during construction. **Indirect impacts:** Disturbance from project noise including construction pile driving and lighting; habitat alteration from introduction and spread of weeds. **Mitigation:** Implementation of biological monitoring reporting, worker awareness program, in **BIO-1** through **BIO-6**; implementation of impact avoidance and minimization measures in **BIO-7** including preconstruction den surveys, den exclusion zone and monitoring during construction. Staff has outlined a compensatory habitat mitigation strategy for listed species in **BIO-20**.
Giant kangaroo rat, San Joaquin antelope squirrel, and Tipton kangaroo rat	**Direct:** Loss of approximately 192 acres of disturbed and natural lands (**Biological Resources Table 5**) that support potential small mammal burrowing habitat; fragmentation and degradation of occupied habitat; increased risk of traffic mortality from construction and operation traffic; crushing or entombing animals in burrows during construction. **Indirect:** Disturbance from project noise including construction pile driving and lighting; habitat alteration from introduction and spread of weeds. **Mitigation:** Implementation of biological monitoring reporting, worker awareness program, in **BIO-1** through **BIO-6**; implementation of **BIO-12** requiring the preparation of a Small Mammal Relocation Plan for preconstruction small mammal trapping and salvage; implementation of **BIO-13** including preconstruction giant kangaroo rat precinct survey, mapping, trapping and relocation from active construction areas; implementation of **BIO-14** including a Tipton kangaroo rat, San Joaquin antelope squirrel preconstruction small mammal burrow survey, mapping, trapping and relocation from active construction areas. Staff has outlined a compensatory habitat mitigation strategy for these listed upland species in **BIO-20**.

Biological Resource	Impact/Proposed Mitigation
Blunt-nosed leopard lizard and other reptiles	**Direct impacts:** Permanent and temporary loss of approximately 192 acres of disturbed natural lands (**Biological Resources Table 5**) which provide small mammal burrow habitat for blunt-nosed leopard lizard; increased risk of take of a California Fully Protected species (no-take species) from project construction and operation traffic; crushing or entombing animals in burrows during construction. **Indirect impacts:** Disturbance from project noise and lighting; habitat alteration from introduction and spread of weeds. **Mitigation:** Implementation of impact avoidance and minimization measures in **BIO-6;** focused surveys for blunt-nosed leopard lizard prior to ground-disturbing activities in **BIO-8**; requirements to prepare and implement a BNLL Impact Avoidance and Minimization Plan in **BIO-8**. Staff has outlined a compensatory habitat mitigation strategy for listed species in **BIO-20**.
Western Spadefoot Toad	**Direct impacts:** Grading of potential aquatic breeding sites and upland refugia habitat during construction; crushing or entombing animals in upland burrows during construction. **Indirect impacts**: Impacts to water quality from stormwater runoff into potential breeding ponds that are adjacent to construction areas; introduction of invasive species and habitat alteration; disruption of breeding and habitat use from project noise and lighting. **Mitigation:** Impact avoidance and minimization in **BIO-6** and avoidance of all identified potential breeding habitat in **BIO-16.**
Swainson's hawk	**Direct:** Permanent loss of approximately 571 acres of alfalfa and other low-growing row crops (**Biological Resources Table 5**) that provide foraging habitat for Swainson's hawk; disturbance of nesting and foraging activities for nesting pairs during construction of the plant site and linear facilities; potential loss or decline of nest trees due to groundwater drawdown and decreased water supply to tree's root system. **Indirect impacts:** Disturbance of nesting activities from operations; degradation and fragmentation of remaining adjacent habitat from edge effects. **Mitigation:** Impact avoidance and minimization measures in **BIO-6**; pre-construction nest surveys and implementation of non-disturbance buffers around nest trees in **BIO-9**. Staff has outlined a compensatory habitat mitigation strategy for listed species in **BIO-20**. More data is needed regarding the source of water supply and the effects of groundwater drawdown to nest trees.
Western burrowing owl and other MBTA protected migratory birds	**Direct:** Direct impacts to approximately 192 acres of allscale scrub and disturbed, non-native grassland habitat which provide nest and forage values to burrowing owl and other MBTA-protected birds; loss of several hundred acres of agricultural lands that may provide forage opportunities; potential loss of eggs and young; disturbance of nesting and foraging activities of nesting pairs near the plant site and linear facilities during construction; potential impacts to wildlife exposed to high concentrations of selenium from

Biological Resource	Impact/Proposed Mitigation
	operation of retention ponds; bioaccumulation of selenium by foraging waterbirds from ingestion of a variety of organisms used as food resources. **Indirect impacts:** Disturbance of nesting activities from construction and operation activities; degradation and fragmentation of remaining adjacent habitat from edge effects. **Mitigation:** Implementation of impact avoidance and minimization measures in **BIO-6**; pre-construction nesting bird surveys for MBTA-protected species in **BIO-10** and requirement to net and monitor retention ponds for avian mortality; performance of focused burrowing owl surveys in **BIO-11;** requirements to prepare a Burrowing Owl Monitoring and Mitigation Plan in **BIO-11.** Staff has outlined a compensatory habitat mitigation strategy for listed species in **BIO-20**.

Overview of Vegetation Impacts and Mitigation Measures

The permanent and temporary loss of allscale scrub and agricultural lands are expected to partially displace home ranges and reduce carrying capacity for a number of special-status wildlife species including, but not limited to: San Joaquin kit fox, blunt-nosed leopard lizard, western spadefoot toad, American badger, Tipton kangaroo rat, giant kangaroo rat, San Joaquin antelope squirrel, short-nosed kangaroo rat, San Joaquin pocket mouse, western burrowing owl, Swainson's hawk, other birds and raptors protected by the Migratory Bird Treaty Act and various California Fish and Game Codes, in addition to commonly occurring small mammals, reptiles, and amphibians. Allscale scrub and intermixed non-native grasslands also provide habitat for a number of special-status plant species and native habitats. All of the above species utilize habitats in the project area consisting of intermixed agriculture lands, disturbed, non-native grasslands and allscrub scrub in western Kern County for forage, cover, and wildlife movement particularly when they adjoin higher quality habitat such as the preserve lands of the Kern Water Bank, Tule Elk State Reserve, Lokern Natural Area, and Buttonwillow Ecological Reserve (**Biological Resources Figure 1**).

Construction[3] of HECA would result in permanent and temporary impacts to vegetation communities occupied by special-status and common plant and wildlife species. Construction of the project site and linear facilities would permanently impact approximately 453 and 44 acres of habitat, respectively (**Biological Resources Table 7**). Construction of the IGCC facility itself would result in the loss of 453 acres of agricultural lands used for forage, dispersal, and cover by small and large mammals, foraging raptors, and other wildlife. Permanent impacts would result from the construction of linear facility infrastructure such as transmission line pole structural bases, the new railroad spur right-of-way, metering stations, valve boxes, and five groundwater wells for the proposed well field. This permanent loss of habitat values

[3] For the purposes of this staff assessment, project-related construction activities are defined as any pre-construction, construction, or operational activities conducted for the project site or linear facilities including any flagging/surveying to delineate pipeline or transmission line routes, access routes, or storage areas; grading, trenching, and backfilling of pipeline segments, any truck or delivery routes; and power plant site construction or ongoing maintenance activities of the power plant site and linear facilities.

could ultimately contribute to larger ecosystem impacts such as decreased wildlife movement and genetic exchange and an overall reduction in the project area’s capacity to support these species.

Biological Resources Table 7
Summary of Permanent Habitat Impacts (Acres) by Facility Type[4]

Habitat Type	Project Site	Construction Staging Area	Railroad spur and laydown	Transmission Line/PG&E Switchyard/ Potable Water Pipeline	Carbon dioxide pipeline[5]	Processed Water Pipeline and well field	Natural Gas Pipeline	**Total**
Allscale scrub/natural vegetation	0	0	0	0	0.11	0	0	0.11
Orchards	0	0	4.5	0.01	0	0	0	4.51
Alfalfa	118.0	0	5.3	3.29	0	1.15	0	127.74
Other row crop	317.3	0	16.2	0	0	0	0.23	333.73
Disturbed/Developed	17.7	0	12.4	0.85	0	0	0	30.95
Total	453.0	0	38.4	4.15	0.11	1.15	0.23	**497.04**

[4] From Table A56-1 (Revised Table 5.2-6), Area of Habitats and Existing Land Use Types within Project area and rounded to the nearest tenth of an acre (URS 2013b).

[5] From URS 2012a and OEHI 2012b.

Construction of HECA (including staging areas) and the linear facilities would temporarily impact approximately 91 and 185 acres of habitat, respectively (**Biological Resources Table 8)**. Temporary impacts would primarily result during construction and installation of the buried pipelines (carbon dioxide, processed water, potable water, and natural gas). Depending on the level of maintenance and vehicle traffic required for each linear facility during operation, more significant impacts in the form of wildlife-vehicle mortality and decrease road crossing attempts could occur. Although the majority of project impacts to allscale scrub would be temporary, staff considers the temporal loss of this habitat to be a significant impact to special-status species, which would require mitigation. Allscale scrub habitat subject to temporary impacts should be considered for revegetation activities following the impacts from construction; however, linear facilities that would be subject to regular vehicular traffic and disturbance along maintenance roads or agricultural fields that would revert back to active cultivation following construction, may not be appropriate areas for revegetation.

BIOLOGICAL RESOURCES Table 8
Summary of Temporary Habitat Impacts (Acres) by Facility Type

Habitat Type	Project Site	Construction Staging Area	Railroad spur and laydown	Transmission Line/ PG&E Switchyard/ Potable Water Pipeline	Carbon dioxide pipeline	Processed Water Pipeline and well field	Natural Gas Pipeline	**Total**
Allscale scrub/natural vegetation	0	0	0	0	28.9	0	3.7	32.6
Orchards	0	0	1.1	0.7	0	2.0	0.6	4.4
Alfalfa	0	59.8	3.7	2.8	0	5.9	3.4	75.6
Other row crop	0	20.0	3.5	0.1	0	1.7	9.4	34.7
Disturbed/Developed	0	11.2	4.3	3.7	0	79.5	30.1	128.8
Total	0	91.0	12.6	7.3	28.9	89.1	47.2	**276.1**

The proposed carbon dioxide pipeline route, located on the lower flanks of the Elk Hills and immediately north of the Elk Hills Conservation Area, is the linear route that supports the most contiguous natural, non-farmland type of habitat in the project area. Therefore, it is staff's opinion that the proposed carbon dioxide pipeline route along the low-lying washes on the lower flanks of the Elk Hills represents the highest quality natural habitat and subsequently, a high potential impact area for biological resources. Within the EHOF, the carbon dioxide pipeline alignment follows established roads or an existing pipeline right-of-way for most of its length. OEHI would construct, own, operate, and maintain the entire length of the carbon dioxide pipeline (HECA 2012b). In addition, portions of the natural gas pipeline route also support areas of disturbed, natural allscale scrub, primarily Sites 1 through 5 as shown on **Biological Resources Figure 2**. Some of these sites represent similar habitat values as the nearby Buttonwillow Ecological Reserve, located north of the project site. The majority of the proposed natural gas pipeline would be installed in existing unpaved farm roads that occur along canals or between fields or disturbed areas along Highway 58.

Conducting focused pre-construction surveys for various plants and wildlife, installing exclusionary fencing or flashing in appropriate habitat areas, mapping and avoiding identified small burrows, and consistent construction monitoring would be sufficient to ensure that most special-status wildlife species (e.g., San Joaquin kit fox, American badger, San Joaquin antelope squirrel, giant kangaroo rat, Tipton kangaroo rat, Buena Vista Lake shrew, burrowing owl, other MBTA-protected nesting birds) as well as special-status plant species do not occur in active construction areas. Since HECA includes the construction of several new linear facilities, pre-construction clearance surveys would need to be phased to account for construction beginning in previously undisturbed or unsurveyed areas at different times and possibly different years. To account for the phasing of construction, staff has required the applicant to prepare species-specific monitoring and mitigation plans for blunt-nosed leopard lizard, Swainson's hawk, burrowing owl, and other upland small burrowing mammals. Since blunt-nosed leopard lizard, a California Fully Protected species, is known to occur in the project area and incidental take is prohibited by state law, additional take avoidance and minimization measures including site clearance and biological monitoring is required and has been incorporated into Condition of Certification **BIO-8**.

Staff has proposed several other conditions of certification to mitigate the project's effects to biological resources. Staff recommends that a Designated Biologist and Biological Monitors be assigned to ensure that impact avoidance and minimization measures for the protection of the sensitive biological resources are properly being implemented during construction. Selection of the Designated Biologist and Biological Monitor(s) is described in staff's proposed Conditions of Certification **BIO-1** (Designated Biologist Selection and Duties) and **BIO-2** (Biological Monitor Selection and Duties). The Designated Biologist and Biological Monitor(s) would be responsible, in part, for developing and implementing the Worker Environmental Awareness Program (WEAP) (Condition of Certification **BIO-4**), which is a mechanism for training the construction workers and site personnel on the protection of the biological resources during construction and would be repeated routinely throughout the lifetime operation of the project for new employees. Environmental awareness training for workers focused on routes to and from the project site as well as adherence to posted speed limits would help reduce traffic mortality to wildlife along roads that would be used by construction workers, power plant staff, vendors, feedstock trucks and any other project-related traffic. Staff’s Condition of Certification **BIO-5** requires the applicant to prepare and implement a Biological Resources Mitigation Implementation and Monitoring Plan (BRMIMP) that incorporates the mitigation and compliance measures required by local, state, and federal LORS regarding biological resources. Staff’s proposed Condition of Certification **BIO-6** (Impact Avoidance and Minimization Measures) describes general impact avoidance measures including project design measures and several construction best management practices (BMPs) to minimize the spread of noxious weeds, minimize noise and lighting impacts, and fugitive dust which would be incorporated into the project’s BRMIMP (**BIO-5**). The incorporation of all of these conditions, among others, would minimize the potential for impacts to sensitive species and habitat during construction and operation of the project.

PROJECT IMPACTS TO SPECIAL-STATUS SPECIES

San Joaquin Kit Fox and Other Mammals

During construction of the project, San Joaquin kit fox and other special-status mammals (American badger, Tipton kangaroo rat, giant kangaroo rat, San Joaquin antelope squirrel, short-nosed kangaroo rat, San Joaquin pocket mouse, and to a lesser extent Buena Vista lake shrew) may be killed or harmed during clearing, grading, and trenching activities or may become entrapped within open trenches and pipes. There is a low potential for Buena Vista Lake shrew to occur in and around wetland edges of irrigation canals especially during high rainfall years in which sufficient vegetative cover occurs; therefore, although this species has a low potential to occur in the project area, it is more likely to occur near wet, aquatic areas located along the West Side Canal and East Side Canal and could become crushed or entombed in burrows in these areas.

Construction and operation activities could result in direct mortality, injury, or harassment of individuals as a result of encounters with vehicles or heavy equipment. Other direct effects could include individual kit fox, badger, and small mammals being crushed or entombed in their burrows, collection or vandalism, disruption of breeding or social behaviors during construction or operation of facilities, habitat loss, and disturbance by noise or vibrations from the heavy equipment especially pile driving during construction to kangaroo rats. Some of these animals may be able to escape direct injury from project ground disturbing activities, but become displaced into adjacent areas making them vulnerable to increased predation, exposure, and stress due to lack of cover. Increased human activity and vehicle travel would occur from the construction and operational maintenance traffic along linear facilities that could disturb, injure, or kill individual kit fox, badgers, or small mammals. These species could also be affected by increased project traffic such as worker, feedstock delivery, and wastestream removal traffic during operation. Other indirect effects that could occur during operation of the project include disruption to habitat connectivity and regional movement in an area identified for core recovery of San Joaquin kit fox in the Recovery Plan (USFWS 1998).

The Recovery Plan identifies several threats to San Joaquin kit fox survival and reasons for decline including natural mortality factors (e.g., predation, starvation, flooding, disease, and drought) and man-induced mortality factors (shooting, trapping, poisoning, electrocution, roadkill). The primary threat to survival is loss and degradation of remaining habitat due to conversion to agricultural, industrial or other incompatible land uses leading to an overall decrease of carrying capacity of remaining habitat. In order to determine the project's potential for impacts to San Joaquin kit fox and other upland mammals, staff evaluated the threats to survival and causes for decline identified in the Recovery Plan and evaluated the project's potential to contribute to any of those factors.

Habitat Loss and Habitat Conversion

The permanent and temporary loss of allscale scrub habitat known to be occupied by American badger, San Joaquin kit fox, Tipton kangaroo rat, San Joaquin antelope squirrel, and giant kangaroo rat and potentially occupied by Buena Vista lake shrew could result in habitat displacement, disruption of breeding and foraging behaviors, and a decrease in landscape capacity to support these upland species. Throughout much of the San Joaquin kit fox's range, natural lands are often times bordered by agricultural fields. Although kit fox may not be able to occupy agricultural fields due to lack of den sites, kit fox may be able to cross agricultural croplands to travel to more suitable, natural habitats. Research has indicated that kit foxes occasionally travel up to 1.5 km (about one mile) into croplands (Cypher et al 2005), although concluded that due to the absence of dens that provide cover and escape habitat, kit fox are subject to an increase in predation while crossing croplands and may avoid croplands altogether. San Joaquin kit fox have been reported to inhabit the margins and fallow lands near irrigated row crops, orchards, and vineyards, and may forage occasionally within these agricultural areas (Cypher et al 2007).

Staff believes San Joaquin kit fox occur in the project area as transients moving between agricultural fields although, as indicated above, are likely limited by the absence of denning habitat in agricultural fields. Kit fox likely den and forage along linear facility footprints, especially linear facilities located along canals. Staff believes the project's impact to 773 acres of all agriculture, natural non-native grasslands, and disturbed lands is a significant loss of habitat in a San Joaquin kit fox core recovery area (**Biological Resources Table 5**). The permanent conversion of 453 acres of agricultural lands at the project site alone would be a significant loss of habitat value, since conversion of agricultural lands to an industrial power plant would be a non-compatible land use for kit fox (**Biological Resources Table 7**). This loss of habitat could also affect the ability of kit fox to meet its food, cover, movement, and reproductive requirements since kit fox are known to utilize croplands especially in areas where farmed fields connect to more suitable, natural lands for denning. Long-term, indirect effects could include habitat alteration by increasing shrub cover in disturbed areas along linear routes and canal corridors, which could increase depradation by coyotes on San Joaquin kit fox in higher shrub cover areas. However, since most linear routes are proposed for disturbed areas along canals, major roadway and railroad rights-of-way, and the potential for an increase in shrub cover is not expected to significantly increase the coyote population due to existing levels of disturbance.

Staff believes other mammal species including American badger, Tipton kangaroo rat, giant kangaroo rat, and San Joaquin antelope squirrel are less likely to occupy or utilize the agricultural lands in the project area, except for areas where the agricultural lands directly abut expansive natural, native habitat types (e.g. near the Kern Water Bank, Kern River Flood Control Channel, Tule Elk State Reserve, and Buttonwillow Ecological Reserve). Staff believes the project's impacts to approximately 192 acres of disturbed natural lands that provide small burrowing mammal habitat for giant kangaroo rat, Tipton kangaroo rat, San Joaquin antelope squirrel and other uplands species is a significant loss of habitat (**Biological Resources Table 5**). Buena Vista Lake shrew has a low potential to occur within construction rights-of-way along irrigation canals particularly during wet years when emergent vegetative cover for this species would be higher.

Temporary impacts to approximately 33 acres of natural allscale scrub habitat could displace home ranges and disrupt breeding and foraging behaviors of kit fox, giant kangaroo rat, Tipton kangaroo rat, American badger among other common and special-status wildlife species over the course of three and a half years, the estimated construction period. Since this impact would occur almost entirely along the carbon dioxide route (approximately 29 out of 33 acres), the greatest potential for impact to kit fox and other mammals species occurs along the carbon dioxide route (**Biological Resources Table 8**). Therefore, it is important that this linear route be revegetated to pre-project habitat conditions.

Traffic and Road Impacts

Roads have long been recognized for causing a number of environmental effects on wildlife including mammals, reptiles, and amphibians, as well as plant communities and ecosystem dynamics. Some effects are obvious and direct such as vehicle-related mortality, habitat loss, and habitat fragmentation from traffic and new road construction. Others are more subtle, long-term effects such as invasion of non-native plant species and habitat alteration, disturbance and stress from increased human encroachment, changes in prey availability and predator abundance, disrupted social ecology, habitat use, dispersal, and reduced productivity and genetic exchange (Bjurlin 2004). The following discussion of traffic and road impacts largely focuses on road mortality to San Joaquin kit fox due to the availability of data and literature throughout the range of this species; however, the effects of increased traffic can be applied broadly to other wildlife species.

Direct and indirect effects of roadways may be detectable over one kilometer (0.60 mile) resulting in a "road-effect zone." The number and type of roads passing through kit fox habitat areas play a major role in determining the impact that roadways and traffic would have on kit fox populations. Bjurlin et al (2005) studied urban San Joaquin kit fox mortality rates among other population parameters such as den use and location, movements, and spatial analysis in urban Bakersfield. This study concluded vehicle strikes are the single largest source of mortality for Bakersfield kit fox sub-population, an important factor for urbanized foxes. Of 156 kit fox carcasses collected between 1985 and 2004, 78 foxes were actively monitored with radiotelemetry collars (Bjurlin et al 2005). Of the 78 monitored foxes, 27 percent were found to be definite vehicle strikes, 16 percent were due to predation, and 28 percent were unknown cause of death but were not likely to have died of vehicle collision due to lack of broken bones or contusions.

Road type played a role in correlation with fox deaths in this study. Bjurlin et al (2005) also found few impacts of two-lane highways (e.g. Stockdale Highway, SR 119 and 58) on kit fox ecology in natural land areas outside of the highly urbanized Bakersfield area. This study also concluded as road width, traffic volumes and speeds increase, potential for direct impacts and vehicle fox-collision strike rate increases. From January 1998 to August 2004, out of the 18 retrieved kit fox carcasses that were actively being monitored with radiotelemetry collars at time of death, 83 percent of fox strikes occurred along arterial roads and significantly fewer strikes occurred along collector, local roads, and highways. Here, roads with four or more lanes accounted for about 78 percent of roadkill of all collared foxes and approximately 90 percent of roadkill was retrieved from roads with posted speed limits of 45 mph or greater (Bjurlin et al 2005). Arterial roads were defined as roads with one to three lanes in each direction, carried the majority of city traffic and connected local and collector road networks to state highway system, and with speed limit usually between 35 to 55 miles per hour. In contrast, in more natural areas outside of urbanized zones, predators remain the primary cause of mortality instead of vehicle collisions for both adult and juvenile foxes (Bjurlin 2004). Cypher et al (2005) found that predation (most often by coyotes and bobcats) accounted for 57 percent of San Joaquin kit fox deaths while vehicle strike accounted for only 9 percent of 222 kit fox deaths in rural, natural habitat areas.

However, the Waller probabilistic road kill method (2005) suggests that the lethality of linear transportation features (roadways, railways, etc) to wildlife are governed primarily by two factors, traffic volume and animal velocity (amount of time wildlife spends on the roadway in a crossing attempt). Waller et al (2005) also concluded that increasing the number of road lanes does not increase the probability of animals being struck, but it decreases the traffic volume in each lane thereby decreasing the probability of being struck in each lane; therefore, the probability of road kill is the same with a two-lane roadway as it would be with four lanes.

Increased wildlife roadkill has been a commonly expressed concern for this project. HECA would not result in the construction of any new roads although road improvements at some intersections have been identified; however, construction and operation would result in considerable amounts of increased traffic on several local and collector roads in a rural setting. Staff believes increased vehicle traffic from the project, especially non-peak traffic during dawn, dusk and nighttime hours, could result in a considerable increase in vehicle-fox strike mortality and all wildlife that occurs on or near roadways. Increased project traffic could affect kit fox movement and general wildlife movement in the following ways: decreased habitat amount and quality, increased road kill, fewer road crossing attempts, and reduced access to resources on opposite sides of roadways that could contribute to long-term population fragmentation into smaller, more vulnerable populations. Since kit fox are crepuscular in nature and mostly active during dawn, dusk, and nighttime hours, times during which construction worker traffic and truck deliveries could occur, the susceptibility of this species to vehicle strikes is greater.

Construction Traffic

Based on a peak monthly workforce need of 2,500 workers per day and average vehicle occupancy of 1.3 people per vehicle, it is estimated that an average of 2,460 daily vehicle trips (1,230 round trips) would result from construction worker traffic for the HECA project. Construction would generate an estimated 2,460 additional vehicle daily round trips along Highway 119, Interstate-5, Stockdale Highway, State Route 43 (Enos Lane), and Tupman Road for a period of approximately three and a half years. These totals include additional truck deliveries of soil fill and equipment materials estimated at 1,440 daily round trips during construction (HECA 2012b). The applicant estimated 656 of all daily construction trips would occur during peak morning hours (0700-0900) while 1,230 trips would occur during peak evening hours (1600-1800) since construction workers would likely be leaving the site in the afternoon or evening hours (HECA 2012b, Table 5.10-3, Anticipated Project Construction Trip Generation). Nighttime construction activities are not planned for this project and construction would mostly occur during normal daylight hours, although exceptions may be needed to meet the construction schedule (HECA 2012b), such as occasional concrete pours needed during night hours or that may require extension of work hours into night hours. The applicant has estimated that approximately 85 percent of construction traffic would occur during daylight and 15 percent during night hours (URS 2012a).

Construction traffic for HECA would primarily be via Stockdale Highway to Dairy Road for general truck deliveries and heavy haul loads. Regional construction traffic would arrive via Interstate 5, Tupman Road, and State Route 58. Rail deliveries of large pieces of equipment would be off-loaded and transported near Buttonwillow and hauled to the project site (HECA 2012b). Construction workers would travel to the project site via two primary routes dependent on the point of origin from the Metropolitan Bakersfield area: worker route 1 would be along westbound Stockdale Highway, southbound to Morris Road, westbound to Station Road into the project site; and worker route 2 would travel along westbound Highway 119 to northbound Tupman Road into the project site (HECA 2012b).

Operation Traffic

Operation of the project would result in the addition of traffic associated with employees, feedstock deliveries, and operation and maintenance (O&M) trips serving the project. There will be regular deliveries of feedstock (petroleum coke and coal) to sustain project operations. Under coal transportation alternative 1 (rail), it is estimated that approximately 532 vehicle round trips per day would occur during operation as O&M traffic and delivery trips of processed materials and feedstock (HECA 2012b, Table 5.10-4, Project Operations Trip Generation – Alt 1, Train Option). The applicant estimates that 176 trips would occur during morning peak hours and 220 trips would occur during peak evening hours. Nighttime operation traffic is expected to be minimal; the applicant has estimated that under alternative 1 (rail) approximately 80 and 20 percent of traffic would occur during the day and night, respectively. Under coal transportation alternative 2 (truck route), it is estimated that approximately 1,453 vehicle round trips per day would occur during operation as O&M traffic and delivery trips of processed materials and feedstock, 900 trips of which would be for feedstock delivery alone (HECA 2012b, Table 5.10-5, Project Operations Trip Generation – Alt 2, Truck

Option). The applicant estimates that 302 trips would occur during morning peak hours and 256 trips would occur during peak evening hours. Under alternative 2 (truck coal option), approximately 66 and 34 percent of traffic would occur during the day and night, respectively (URS 2012a).

Vehicle Mortality Strike Analysis

The applicant prepared an analysis looking at the potential for San Joaquin kit fox mortality due to vehicle strikes from project traffic. Since construction and operation traffic would pass through portions of the western Kern County Recovery Area, the Antelope Plain/Semitropic/Kern and Urban Bakersfield satellite populations, and habitat linkages throughout these recovery areas, the applicant first evaluated the project's contribution to baseline traffic levels along the primary roadways that construction and operation traffic would be using for the project (i.e. Interstate-5, Tupman Road, SR 46, SR 119, Stockdale Highway). State Route 58 was not identified as a worker construction route by the applicant, so data was not provided for this roadway. However, staff believes that workers would periodically utilize State Route 58. Using known San Joaquin kit fox mortality rates and traffic levels, the applicant then estimated a project-related road mortality (incidental take) amount for each roadway segment to kit fox over the course of 20 years for operation and three years for construction.

The applicant calculated construction-related incidental take to be 2.39 foxes over three years. Operation-related (employee traffic, material, feedstock delivery, etc) take under Alternative 1 (rail) and Alternative 2 (truck route) over the course of 20 years was estimated to be 11.57 foxes and 26.54 foxes, respectively (HECA 2012b). The applicant determined the baseline take estimate for the individual roadway segments using different sources and methods which staff believes make the calculation of incidental take non-comparable between methods. The applicant evaluated roadway segments along I-5, SR 46, SR 119, Tupman Road, and Stockdale Highway that would be utilized for construction and operation, but only evaluated the portion that overlapped with San Joaquin kit fox core recovery areas. Staff disagrees with this approach since kit fox occur outside of core recovery areas and incidental take of kit fox in the form of fox-vehicle collisions would undoubtedly occur beyond the boundaries of the core areas and the roadway segments that the applicant evaluated. The direct and indirect impacts of traffic to this species and all wildlife would extend beyond the finite boundaries of the core recovery areas as described above not only as take in the form of vehicle-fox strikes, but also as the loss of foraging opportunities, a reduction of crossing opportunities, habitat alteration, disturbance and stress, changes in prey availability, predator abundance, and habitat use. The applicant used Figure 9 in Bjurlin et al (2005) to determine a baseline take estimate along the select roadway segments that the project would be using. However, staff believes this figure should not be used as a standard for determining baseline take for the project, since Figure 9 in Bjurlin et al (2005) represents fox strikes in relation to fox-vehicle collisions along arterial and collector roads at intersections with other linear rights-of-way (canals, golf courses, other collector and arterial roads, highways, railroads). Lastly, staff believes operational take should be calculated over the life of the project, not 20 years as the applicant calculated. Staff believes it may be more appropriate to evaluate vehicle-fox mortality impacts considering the project's contribution to existing traffic volumes and intersection of proposed construction and operation routes with other types of linear right-of-ways.

Likewise, staff believes a more applicable method for determining wildlife incidental take would be to determine roadkill probability using Waller et al (2005) methods, which looks at traffic volumes and the time it takes an animal to cross the kill zone.

Regional Movement

As mentioned previously, the project is proposed for an area located within a core recovery area for San Joaquin kit fox, natural lands of western Kern County, which serves as a linkage point between other core areas and satellite populations. For small populations like these identified in the Recovery Plan (USFWS 1998), the effects of habitat fragmentation associated with transportation networks and risk of extinction from catastrophic events is greater for small populations. Therefore, movement of individuals between these metapopulations is critical for maintaining gene flow and avoiding inbreeding effects (Bjurlin et al 2005). For example, the Department of Water Resource's Kern Fan Element (Kern Water Bank) provides an important linkage as a corridor between the Kern River Parkway through Bakersfield and the western Kern County population. Connecting large blocks of isolated lands to larger, core population areas that are naturally more stable is an important element to San Joaquin kit fox recovery (USFWS 1998).

Another potential effect from increased construction and operation traffic is unwillingness for kit fox and other wildlife to cross roads or "road avoidance" if traffic is consistent enough on the same route and over a long period of time. Studies have shown road avoidance and decreased road crossings to be the case with San Joaquin kit fox. However, kit fox have appeared to adapt to urban areas such as Bakersfield and data on the movements of radio-collared animals show that kit foxes frequently cross roads and often do so in a habitual manner. The movements of radio-collared kit foxes in Kern County near I-5 were monitored and several fox utilized habitat in a 1.15 square mile area and most exhibited parallel movements and home range patterns; on only two occasions were foxes located on the opposite side of the highway from their primary area of use. A study of developed (oil fields) and undeveloped sites (Lokern Natural Area) in western Kern County concluded denning, foraging, and home ranges ranged from 1.36 to 6.66 square km (0.76 to 2.57 square mile) in undeveloped plots (Spiegel et al 1991). Bjurlin et al (2005) concluded the majority of crossings occurred on local roads in the metropolitan Bakersfield area but the majority of mortalities occurred on arterial and collector roads with higher traffic volumes indicating that low traffic volumes and slower speeds associated with local roads may decrease the danger to kit fox.

The study also showed that kit foxes did not appear to prefer or avoid dens that were in close proximity to major roadways in urban environments since natal dens were found within 20 meters form roadways in urban Bakersfield but in many cases, animals maintained territories that did not bring them in frequent contact with major roads. Of 327 kit fox dens used from 2001 to 2004, 68 percent of strikes on major roads occurred within two road widths of an intersection (Bjurlin et al 2005). In this same study, kit foxes died more often than expected by chance at intersections of roadways with other types of linear rights-of-way such as other local and collector roads and canals and strikes were often within one road width of the intersection. This is likely because species of the family Canidae (dogs, wolves, foxes, coyotes) use linear features for travel. This is important for HECA since several project worker routes occur along local and collector roads and intersections with canals occur in the project area, intersections where more strikes could occur since kit fox likely utilize canals for movement. In urban Bakersfield, kit fox have shown some preference for den sites with respect to adjacent land uses; of 471 dens assessed from 1997 to 2004, 36 percent were located along the banks of canals or along detention basins. Intersection improvement areas proposed along SR 119, SR 43, Stockdale Highway, Tupman Road, and Dairy Road could therefore endanger kit foxes that use roadside dens. For HECA, if traffic volumes remain large enough along particular roadways for a long enough period of time, kit fox could shift dens to sites that would not bring them in frequent contact with traffic or the roadways, or avoid crossing roadways in general. This could have long-term implications on kit fox movement in the immediate project area particularly along rural, local roads such as Station, Dairy, Tupman, and Morris roads among others where traffic volumes would be significantly increased during operation of the project.

Mitigation for San Joaquin Kit Fox and Small Upland Mammals

Direct impacts to San Joaquin kit fox and other mammals would occur from proposed project construction and operation including individual mortality from vehicles strikes, vegetation removal, loss of habitat, and displacement of individuals. Incorporation of staff's Conditions of Certification **BIO-1** through **BIO-6** would minimize the potential for construction impacts to kit fox and other burrowing small mammal species. The applicant has recommended impact avoidance and minimization measures to reduce the potential for direct and indirect impacts to San Joaquin kit fox and other wildlife, including combined terrestrial wildlife pre-construction surveys covering affected areas and a 200-foot survey buffer; den surveys and unoccupied den excavation; and combined ground disturbance monitoring for terrestrial wildlife. Staff has incorporated portions of these mitigation measures into staff's proposed Condition of Certification **BIO-7**, which requires that the applicant conduct focused den surveys prior to construction for San Joaquin kit fox and American badger, establish exclusion zones, and continue monitoring the activity of potential dens identified in construction areas. **BIO-7** also requires that the applicant follow the USFWS's *Standardized Recommendations for Protection of the San Joaquin Kit Fox Prior to or during Ground Disturbance* for avoiding impacts to this species (USFWS 2011). Staff's proposed Condition of Certification **BIO-12** requires that the applicant prepare and implement a Small Mammal Relocation Plan, which would include the identification of potential release sites, and monitoring and reporting of small mammals at release sites, among other trap and relocation details. Proposed Condtion of Certificaiton **BIO-13** requires the applicant to perform pre-construction precinct surveys and mapping for giant kangaroo rat and trap and relocate any giant kangaroo rats captured within construction areas in order to minimize take and mortality of this species during construction, in accordance with the Small Mammal Relocation Plan. In addition, proposed Condition of Certification **BIO-14** requires the applicant to perform a pre-construction small mammal burrow survey to better define the subsequent trapping area and relocate any trapped Tipton kangaroo rat and San Joaquin antelope squirrel in order to minimize take and mortality of these species during construction. Temporary loss of habitat values would occur during construction, grading, trenching, and backfilling for the various pipelines along linear facilities. After the completion of construction activities, the applicant would be required to restore the natural, relatively undisturbed allscale scrub habitat along linear facilities to pre-project conditions per staff's proposed Condition of Certification **BIO-18** (Revegetation Plan).

As discussed above, Buena Vista Lake shrew has a low potential to occur within construction rights-of-way along irrigation canals particularly during wet years when emergent vegetative cover for this species would be higher. Likewise, staff does not believe the project would significantly impact this species and mitigation specific to this species is not warranted; however, the implementation of **BIO-1** through **BIO-6, BIO-12, BIO-13,** and **BIO-14** in addition to the measures listed above would further reduce the potential for project impacts to Buena Vista Lake shrew.

Staff believes the project's increase in traffic volumes could have an effect on San Joaquin kit fox; however, additional vehicle-kit fox mortality and data analysis is required. Staff believes the project's impacts to approximately 773 acres of allscale scrub, agricultural lands, and disturbed habitats along canal roads that provide habitat to San Joaquin kit fox in a San Joaquin kit fox Core Recovery Area is a significant impact that requires mitigation. The project's impacts to approximately 192 acres of natural allscale scrub and other disturbed lands that support small mammal burrowing habitat is a significant habitat loss to giant kangaroo rat, San Joaquin antelope squirrel, and Tipton kangarro rat and is a significant impact that requires mitigation. Staff has proposed Condition of Certification **BIO-20** which requires the applicant to secure offisite compensatory mitigation lands that meet species habitat criteria for San Joaquin kit fox, giant kangaroo rat, Tipton kangaroo rat and San Joaquin antelope squirrel. Acquistion and preservation of offsite mitigation lands with a conservation easement would also permanently secure lands as habitat for American badger, San Joaquin pocket mouse, short-nosed kangaroo rat and other common and special-status mammals. In order for staff to prepare the FSA/FEIS, staff needs information on the applicant's mitigation proposal to offset the project's direct and indirect effects to these species. This proposal should be based on HECA's specific vehicle-fox mortality analysisand habitat loss in order to determine the amount of incidental take attributable to the project and ultimately the necessary mitigation to offset the project's impacts. With the incorporation of the above conditions of certification, the project's impacts to these species would be reduced; however, until additional data is provided regarding the project's impacts and overall mitigation strategy, staff cannot determine if the project's impacts to San Joaquin kit fox, giant kangaroo rat, Tipton kangaroo rat, and San Joaquin antelope squirrel would be reduced to below a level of significance in accordance with CEQA.

Blunt-nosed Leopard Lizard and Other Reptiles

The greatest threats to blunt-nosed leopard lizard (BNLL) survival include habitat disturbance, destruction, and habitat fragmentation. Construction of facilities related to oil and natural gas production, wells and pads, storage tanks, pipelines and access roads degrade habitat and cause direct mortality to BNLL. The displacement of BNLL and other species of lizards to adjacent lands due to loss or degradation of habitat may result in an inability to survive if the habitat is already occupied or unsuitable for colonization (USFWS 1998).

The potential for direct impacts from project construction activities to BNLL, coast horned lizard, and other reptiles includes individual mortality from vehicles and equipment on roadways, entrapment in construction-related trenches or pipes, buried in burrows by equipment, avoidance of certain habitats, modification to breeding and/or foraging behaviors, and reduced carrying capacity of natural scrub habitat and neighboring lands known to be occupied by BNLL. Regular vehicle traffic and off-road vehicle use are known to be a large source of mortality of blunt-nosed leopard lizard. Typically roads surround, occur in close proximity, and often bisect remaining natural habitat areas, which further increases the risk of mortality to BNLL from vehicles and fragments habitat (USFWS 1998). Other regional threats to survival of this species include livestock overgrazing that results in removal of herbaceous vegetation and shrub cover and destruction of rodent burrows used by lizards for shelter, pesticide use, and vehicle mortality. Unlike cultivation of row crops which precludes BNLL presence, low to moderate livestock may be beneficial since light grazing may help promote low, sparsely growing herbaceous cover which is favored by BNLL (USFWS 1998).

The project’s contribution of 2,460 and 1,453 daily vehicle trips during construction and operation under alternative 2 (coal delivery truck route option), respectively, would increase the potential risk of road mortality to BNLL and other reptiles. Consistently high traffic levels in natural habitat areas where BNLL is known to occur over long periods would cause fragmentation of habitat and reduction of movement, motility, and gene flow of this federally- and state-listed species that is also a California Fully Protected species. In particular, project traffic along the SR-58 northern extension of the natural gas pipeline, Stockdale highway, the transmission line/potable water facilities immediately north of the Tule Elk State Reserve, and carbon dioxide pipeline route south of the California Aqueduct, all proposed in and around allscale scrub habitat, are the project facilities that pose the largest threats to habitat loss and potential for direct road mortality to BNLL. Staff believes the project’s direct loss of approximately 192 acres of natural allscale scrub and disturbed lands which provide small mammal burrow habitat for blunt-nosed leopard lizard is a signicant impact to this species. The construction of the carbon dioxide pipeline represents the greatest risk, habitat loss, and potential for take and impacts to BNLL. Sites 1 through 5 along the natural gas pipeline route also represent potential BNLL habitat although this species has not been found to occupy these sites following protocol-level surveys performed by the applicant (**Biological Resources Figure 2**). In addition, operation and maintenance activities along the carbon dioxide pipeline route, an area immediately south of the EHOF could result in take of BNLL primarily in the form of direct road mortality from project traffic.

Mitigation for BNLL and Other Reptiles

Direct impacts to BNLL would occur from HECA construction and operation including individual mortality from vehicles strikes, loss of habitat and fragmentation, and displacement of individuals. Incorporation of staff’s Conditions of Certification **BIO-1** through **BIO-6** would minimize the potential for construction impacts to BNLL, coast horned lizard, and other reptilian species. Staff has proposed Condition of Certification **BIO-8**, which requires the applicant to prepare a BNLL Impact Avoidance and Minimization Plan to further minimize the potential for take during construction and operation of the project. In particular, this plan would take into consideration the phasing of linear construction and how clearance surveys, exclusion fencing, and fence and burrow monitoring would also be phased in order to ensure BNLL remain clear of active construction areas. Condition of Certification **BIO-8** also requires that various BNLL impact avoidance measures be incorporated including scheduling surface ground disturbing during the BNLL active season (approximately April 15 to October 15) to the greatest extent practicable, in particular along the carbon dioxide pipeline route and within Sites 1 through 5 along the natural gas pipeline route where this species is mostly likely to be encountered, minor shifts in proposed pipeline alignments in order to avoid potentially occupied small mammal burrows, presence of biological monitor(s), and strategic installation of exclusion fence flashing to preclude BNLL presence in construction areas. Staff's proposed Conditions of Certification **BIO-8** and **BIO-20** require the applicant to secure off-site mitigation lands that meet habitat criteria of BNLL as compensatory mitigation to offset the loss of BNLL habitat.

Blunt-nosed leopard lizard is a California Fully Protected species under California Fish and Game Code Section 5050, and therefore incidental take of the species cannot be permitted as defined by Section 86 of the Fish and Game Code. Therefore, take avoidance and minimization measures must be implemented by the applicant throughout construction and operation (as determined in the subsequently prepared BNLL Impact Avoidance and Minimization Plan per **BIO-8**) to ensure take does not occur. Staff concludes that even with the implementation of the identified take avoidance and minimization measures, incidental take of BNLL would likely occur over the life of the project. Since avoiding take of this species cannot be guaranteed for the life of the project, HECA may not comply with California Fish and Game Code Section 5050 and CESA.

Staff considers the project's impacts to BNLL to be significant and unavoidable impacts under CEQA which require mitigation. For BNLL, CDFW and USFWS typically require compensatory mitigation for a project's impacts to habitat loss that is determined significant under CEQA. Staff notes that any impacts due to habitat loss of BNLL even if mitigated as required under CEQA, may violate CESA and the California Fish and Game Code Section 5050 due to the species' status as a California Fully Protected species and the likelihood of take of this species; therefore, it is unclear whether the project will comply with these LORS.

Giant Garter Snake: Impacts and Mitigation

As discussed previously, giant garter snake has a low potential to occur in the project area due to presumed extirpation from the southern-most portion of the San Joaquin Valley, lack of known occurrences and lack of essential habitat components in the project area. However, staff recommends the implementation of impact avoidance and minimization measures during construction activities along any of the project's linear facilty routes proposed along canals, primarily the railroad spur and 15-mile brackish water pipeline to further minimize the potential for impacts to this species during construction. Likewise, staff has incorporated wildlife agency guidance on this species and construction avoidance measures into Condition of Certification **BIO-15**. With the implementation of this measure, the potential for impacts to giant garter snake would be reduced to less than significant levels.

Western Spadefoot Toad: Impacts and Mitigation

The applicant indicates that western spadefoot tadpoles were found in a seasonal depression between the West Side Canal/Outlet Canal and California Aqueduct during 2009 surveys. Western spadefoot toads are historically known from the Central Valley including the southern San Joaquin Valley with a few extant records remaining and can persist in seasonal wetlands and ponds with emergent vegetation that typically do not inundate long enough to support non-native bullfrogs, crayfish, or other non-native predators of tadpoles. Western spadefoot toad is a California Species of Concern that is declining throughout its range primarily due to habitat loss and agricultural conversion of grasslands. Potential impacts that could occur to this species include terrestrial and aquatic habitat loss and direct mortality of individuals during project grading, vegetation clearing, and pipeline trenching for the project's linear facilities as well as disruption of breeding behaviors, disturbance by noise or vibrations from equipment, and introduction of weeds and exotic plant species that can displace native seasonal wetland vegetation.

Staff believes the depressional seasonal wetland areas and upland areas that were identified between the West Side Canal and California Aqueduct could potentially support spadefoot toads and be impacted during project construction. In addition, several small, disturbed mostly unvegetated seasonal wetlands that were identified along State Route 58 could represent habitat for this species and be impacted during construction and grading for the natural gas pipeline. The applicant indicated that during times of increased rainfall, the depressions identified along the State Route 58 natural gas linear inundate and form shallow pools of water that persist for at least 10 to12 days during the growing season and the best evidence for the length of ponding in the shallow depressions was the presence of mature Lindahl's fairy shrimp (*Branchinecta lindahli*) observed during the March 2012 surveys (URS 2013c); however, given that these shallow depressions are mostly unvegetated, the habitat suitability for western spadefoot toad is reduced. Lindahl's fairy shrimp is a non-listed vernal pool crustacean that is common in arid regions of California in turbid and clear-water short-lived pools and live in seasonal depressions that typically last from 5 to 30 or more days before drying (Eriksen and Belk 1999).

The applicant did not provide a habitat assessment, GPS'ed mapped location of the single occupied seasonal pond, or quantified acreage of potential habitat of this species within the project area, nor did the applicant propose any specific mitigation measures or impact avoidance and minimization measures for western spadefoot toad. Staff believes additional baseline field data is needed on the occurrence of other suitable habitat areas in the project area. In preparation of the FSA/FEIS, staff requests that the applicant perform an upland refugia and aquatic habitat assessment(s) preferably during the wet season (defined as October 15 to April 15 of any given year) and following sufficient winter or spring rains in order to identify potential depressional areas and upland refugia that may provide habitat for western spadefoot toad. All linear facility construction rights-of-way should be subject to the habitat assessment. All potential ponding areas should be identified and mapped with a GPS unit and information to be collected at each GPS'ed potential breeding area includes, at a minimum: the specific numbering system of each potential breeding area, presence of tadpoles and species (if any), habitat community, microhabitat features, observed plant species, observed wildlife species including invertebrates, water temperature, approximate depth and surface area, and level of disturbance.

Staff believes that with the project's potential for impacts to potential breeding habitat of this species with its limited range in the southern San Joaquin Valley and at least one identified occurrence of this species in the project area, significant impacts to this species could occur and mitigation is required. Following performance of the western spadefoot toad habitat assessment, any potential habitat areas would be identified and mapped. In order to reduce the potential for effects to this species and habitat areas during construction, staff has proposed Condition of Certification **BIO-16**, which requires the project owner to install fencing and avoid all identified potential breeding wetland depressions and upland areas within a minimum 100 foot buffer from construction activities, specifically the single depressional area in which spadefoot toad was observed between the West Side Canal and California Aqueduct. With the implementation of Condition of Certification **BIO-16** the potential for impacts to western spadefoot toad and potential wetland breeding depressions would be reduced; however, until additional data is provided regarding the occurrence of additional habitat areas, staff cannot determine if the project's impacts to western spadefoot toad would be reduced to below a level of significance.

Swainson's Hawk: Impacts and Mitigation

During protocol-level surveys performed for this species, 12 active raptor nests were found within the survey area, six of which were confirmed Swainson's hawk nests (URS 2012a, Figure A45-2). All six Swainson's hawk nests appear to be within a 0.25 mile of either the project site or a proposed linear facility and therefore could be affected by construction noise or other construction disturbances during the nesting season. Swainson's hawk nest numbers 05, 06, 19, and 21 occur within immediate proximity (less than 0.25-mile) to the 15-mile processed water pipeline; nest #29 occurs within immediate proximity (less than 0.25-mile) of the natural gas pipeline route along Highway 58; and nest #22 is located approximately one mile due east of the project site in the Tule Elk State Reserve (URS 2012a, Figure A45-2). The applicant estimates that construction of the project would span a 42-month period and that construction of the railroad spur under (coal delivery option #1) would begin early in the construction period so that materials and equipment could be delivered to the project site via the proposed rail line; construction of the project's linear facilities each would require approximately six months to construct (HECA 2012a).

The potential for direct impacts to Swainson's hawks include the loss of nest sites, eggs, and/or young; loss or decline of nest trees, abandonment of active nests; permanent loss of foraging habitat; and disturbance of nesting and foraging activities of hawk pairs. Indirect impacts to Swainson's hawks during construction and operation can include increased road kill hazards, and loss of prey items and food sources due to a decreased number of fossorial mammals. Five of the Swainson's hawk nests found during 2012 surveys occur along the 15-mile brackish water pipeline route and staff believes groundwater drawdown around the well field may result in loss or gradual decline in health of these nest trees. In addition, the project would result in the loss of approximately 571 acres of alfalfa and other low-growing row crops potentially used as foraging habitat for this species (**Biological Resources Table 5**).

Impacts to Nest Trees

Six confirmed Swainson's hawk nests and up to six other confirmed raptor nests (great-horned owl and red-tailed hawk) were found in the same survey area during 2012. Tree species identified during Swainson's hawk nest surveys that are being utilized by several raptors and common ravens (*Corvus corvax*) for nesting include willow (*Salix* sp.), tamarisk (*Tamarisk chinensis*), Fremont cottonwood (*Populus fremontii*), fruitless mulberry (*Morus alba*), and eucalyptus (*Eucalyptus* sp.). Many man-made structures such as power poles and a grain silo also provide nesting sites. Staff estimates up to 13 nest trees with either potential or confirmed nests occur within approximately two miles of the applicant's proposed groundwater well field (URS 2012a, Figure A45-2). The majority of these nest trees occur along canal levees of large named canals including the KRFCC and West Side Canal and other smaller unnamed agricultural canals and ditches and are likely supplied to some extent by irrigation runoff that accumulates in irrigation canals.

Most woody vegetation of lower elevation southwest riparian ecosystems are believed to be dominated by phreatophytic species, that rely heavily on alluvial groundwater. Native tree species such as Fremont cottonwood and black willow (*Salix gooddingii*), and non-native tamarisk dominate these lower-elevation riparian habitats in the southwest. Fremont cottonwood is considered a facultative phreatophyte, a plant species that utilizes moisture from groundwater for a portion of their water requirements but can also acquire water from other soil sources. Cottonwoods typically occur in areas with depth to groundwater of less than 5 meters whereas black willow is an obligate phreatophyte that is more shallowly rooted than cottonwoods. Tamarisk is also considered facultative phreatophyte but is much more drought tolerant than the other two native species (Horton et al 2001). A study that evaluated two riparian riverine sites in Arizona, concluded that an increase in depth to groundwater caused a reduction in shoot water potential and increased canopy dieback and mortality in both willows and cottonwoods. Likewise, both species experienced an increased canopy dieback and mortality when depth to groundwater increased above an apparent threshold of 2.5 to 3.0 meter. In this same study, tamarisk was more tolerant of water stress imposed by deeper groundwater depths and Fremont cottonwood was more tolerant of deeper groundwater sources than willows. Horton et al (2001) also concluded that some regulation of surface water flows may benefit mature riparian forests since in this case, riparian trees were in better physiological condition when depths to groundwater ranged between 3.5 to 4.0 meters (approximately 10 to 12 feet) and riparian trees showed signs of decline once groundwater depths fell below 3 meters. Another study that looked at the effects on riparian vegetation from removing water supply and effluent generated by wastewater treatment plants to the Salinas River concluded that it was essential that the existing water table not be lowered beyond the root zone of approximately 10 feet of willows and cottonwoods (Warner and Hendrix 1984). The depth to groundwater in the area of the well field ranges from 25 to 30 feet (BVW 2010a) and staff estimates that the identified nest trees in the two-mile radius around the well field could experience a groundwater drawdown ranging from four to 12 feet over the course of the 25-year licensing of the project.

Since the majority of nest trees in the proposed well field area occur along canal roads of the KRFCC and West Side Canal and the estimated depth to groundwater is 25 to 30 feet in this area, well below the estimated depth of water use by cottonwoods and willows, staff concludes the trees along these canals are supported to some extent by groundwater but also perched subsurface flows. Depth to groundwater in the project area is estimated to range from 20 to 130 feet below ground surface (BVW 2010a). Staff believes the majority of water supported in irrigation ditches between agricultural fields is primarily irrigation source runoff during the growing season and to a lesser extent, stormwater runoff during the rainy season from Kern River overflow since the majority of stormwater is diverted into other flood control channels farther east of the HECA project before reaching the project area and KRFCC. For alfalfa, the primary crop in the project area, the harvest and irrigation windows typically parallel each other with generally four monthly harvests beginning in May to August with irrigation typically following each harvest (USDA website ref). During an October 2012 site visit, portions of the West Side Canal supported sporadic, shallowly ponded water and hydrophytic vegetation (i.e. salt grass, *Distichlis spicata*) was observed in some areas which suggests that these areas may inundate with irrigation runoff for various periods during the growing season. For a full discussion of surface water and groundwater existing conditions in the project area, see the **Soil & Surface Water** and **Water Supply** sections of this PSA/DEIS.

Although water supply to the root system of nest trees in the project area are believed to be sourced by irrigation runoff in agricultural canals, more definitive analysis is needed on the baseline groundwater levels and water source of the nest trees that occur in the project area. If water drawdown is consistent enough over the course of several years, staff believes the decrease in water supply to the tree's root system could result in gradual decline and eventually nest tree failure. If the long-term drawdown of water resulted in nest tree failure or mortality such as canopy dieback, limb failure or other health or structural indicators due to the project's groundwater pumping, this could constitute incidental take of Swainson's hawk under CESA, which would require take authorization and mitigation for loss of Swainson's hawk nest habitat. Given Swainson's hawk high site fidelity with nest sites, lack of suitable raptor nesting habitat in the project area, staff concludes the project could result in a reduction of nesting habitat, which is a significant impact that would require mitigation.

Foraging Habitat

Staff also believes the loss of approximately 571 acres of agricultural lands including alfalfa, wheat, onion fields, and other crop types that provide forage value is a significant loss of foraging habitat for this species (**Biological Resources Table 5**). Nest #22 is within the Tule Elk Reserve and within one mile from the IGCC project site; construction of the IGCC facility alone would result in loss of 453 acres of Swainson's hawk forage habitat. The CDFW guidance on habitat compensation for this species specifies that to mitigate for the loss of foraging habitat, Habitat Management (HM) lands (agricultural lands or other suitable habitats which provide forage habitat) should be provided by the applicant based on the distance of the project facilities (< 1 mile, between 1 and 5 miles, or between 5 and 10 miles) to active nests trees:

- projects within one mile of an active nest should provide 1 acre of HM land for each acre impacted (1:1 ratio) if at least 10 percent of the lands are secured by fee title acquisition for active management of habitat and remaining 90 percent of lands protected by a conservation easement; OR

0.5 acre of HM land for each acre impacted (0.5:1) if 100 percent of lands are met by fee title acquisition or a conservation easement which allows for active management of habitat for prey production.

- projects between one and five miles from an active nest should provide 0.75 acre of HM lands for each acre impacted (0.75:1). All HM lands may be protected through fee title or conservation easement of suitable foraging habitat.
- projects between five and 10 miles from an active nest should provide 0.50 acre of HM lands for each acre impacted (0.50:1). All HM lands may be protected through fee title or conservation easement of suitable foraging habitat.

Swainson's Hawk Mitigation

The applicant has recommended impact avoidance and minimization measures to reduce the potential for impacts to Swainson's hawks, including bird pre-construction surveys within 200 feet of the project disturbance areas, bird nesting activity surveys; and bird nest protection. The applicant has also proposed Swainson's hawk avoidance and minimization measures following the *Recommended Timing and Methodology for Swainson's Hawk Nesting Surveys in the California's Central Valley* (Swainson's Hawk Technical Advisory Committee 2000) as well as predatory bird minimization measures including the removal of predatory bird nests (HECA 2012b). Since several Swainson's hawk nests were confirmed active during 2012 surveys, staff believes that 200 feet would not be a large enough distance to avoid construction impacts to an active Swainson's hawk nest. California Department of Fish and Wildlife's guidance on this species calls for a buffer area of 0.25-mile between an active nest and any new intensive disturbances such as heavy equipment operation during construction or other project-related activities that may cause nest abandonment or premature fledging between March 1st through August 15th; the nest avoidance buffer should be increased to 0.50 mile in nesting areas outside of urban areas (CDFG 1994).

In Condition of Certification **BIO-9** (Swainson's Hawk Impact Avoidance Measures), the applicant would be required to conduct focused, preconstruction surveys within 0.50-mile of all project facilities and a minimum construction avoidance buffer of 0.50 mile around any active Swainson's hawk nests following the recommended survey protocol for this species (Swainson's Hawks Technical Advisory Committee 2000). This impact avoidance buffer could be reduced during the nesting season by the project's Designated Biologist and compliance project manager based on consultation with CDFW along with monitoring of the nest site for signs of stress or disturbance by the project's Designated Biologist.

Staff understands that the construction of all project facilities would not occur simultaneously and it is not feasible for HECA including all linear facilities to be constructed entirely outside of the nesting season. Therefore, staff has included a requirement in Condition of Certification **BIO-9** for the applicant to prepare a Swainson's

Hawk Monitoring and Mitigation Plan that would account for the phasing of construction and need to phase preconstruction surveys. To the extent possible, construction activities would be timed to occur outside of the nesting season of Swainson's hawk, approximately March 1 through August 15 of each construction year. Due to the occurrence of at least five active raptor nests, three of which are Swainson's hawk, along the 15-mile long processed water pipeline, the start of construction on this linear facility outside of the Swainson's hawk nesting season and the implementation of a minimum 0.50-mile buffer is particularly critical to minimize impacts to these nests during construction of this facility. In addition, incorporation of staff's Conditions of Certification **BIO-1** through **BIO-6**, which require monitoring and reporting of nest sites by biological monitors during construction, worker awareness training, and other impact avoidance measures, would help in minimizing impacts to Swainson's hawks.

Given the occurrence of at least six known active Swainson's hawk nests in the project area including linear facilities, presence of suitable foraging agricultural lands and estimated impacts to 571 acres of foraging habitat loss, staff believes habitat mitigation lands that meet foraging habitat criteria by Swainson's hawk should be acquired. Staff's proposed Conditions of Certification **BIO-9** and **BIO-20** require the applicant to secure off-site mitigation lands as compensatory mitigation to offset project impacts to species such as Swainson's hawk. With the incorporation of the above conditions of certification, the project's impacts to Swainson's hawk would be reduced; however, until additional data is provided regarding the project's impacts and overall mitigation strategy, staff cannot determine if the project's impacts to Swainson's hawk habitat would be reduced to below a level of significance. In order for staff to prepare a FSA/FEIS, the applicant must provide a mitigation proposal to offset the project's effects to nest and forage habitat loss for this species as well as additional data on the water supply source and effects of groundwater pumping to nest trees.Until further analysis and consultation with CDFW is performed on the project's potential for impacts to Swainson's hawk nest trees and potential for take, it is unknown whether the project would comply with MBTA, CESA, and Fish and Game Code Section 3503.

Western Burrowing Owl: Impacts and Mitigation

Western burrowing owls and recent sign has been observed immediately north of the project site, southeast of the transmission line/potable water route and project site, and along the natural gas pipeline route. Adults and owlets were observed west of the natural gas alignment along Brandt Road during 2012 and at least six burrowing owls have been observed at one time during July 2012 at Tule Elk State Reserve and appear to be part of the same owl family group (URS 2012a). Focused protocol-level surveys were not performed for burrowing owl and observations of this species presence in the project footprint were combined with other biological surveys (i.e. BNLL, Swainson's hawk and wetland delineation surveys). Therefore, staff does not have information on which pairs or groups of owls are in fact breeding in the project area. The home range of burrowing owls has been reported to range from 280 in irrigated lands of Imperial Valley to 600 acres and may be much larger in non-irrigated grassland areas such as the Carrizo Plain (CDFG 2012b). The mean home range for 11 male burrowing owls in 1998 and 22 males in 1999 was 177 ha (437 acres) and 189 hectares (467 acres), respectively, at Naval Air Station in Lemoore, California which is located south of

Fresno (Bloom 2003). Based on telemetry results, foraging generally occurred within a 600-meter radius around the nest burrow (roughly 300 acres) although home range of burrowing owls can widely range and is not well understood (CDFG 2008). Moreover, diurnal home range for owls can be 150 feet on both sides of burrow while nocturnal home range can be much larger, for example one square mile per owl pair, and several owls can overlap in that one square mile (Bloom pers. comm.). Male burrowing owls often move greater than 1,000 meters when foraging in the breeding season and home ranges can often times overlap (Bloom 2003). Burrowing owls also show relatively high site fidelity and returned to successful nest sites between nesting years. For example, one study concluded adult males and females nesting in formerly used nest sites at 75 percent and 63 percent rates, respectively, and more commonly owls at least return to the same nest area without necessarily reusing the same burrow (CDFG 2012b).

Since burrowing owls were observed in generally the same area following 2011 and 2012 field surveys and given the best available scientific data available on home range and burrow use, the owls observed are likely resident owls or first-year fledglings or family groups that have not entirely dispersed and have returned to the area to nest. The burrows or culverts at which the owls were observed are likely being used for nesting or as satellite burrows which typically occur within 75 meters of nest burrows, year-round cover or roosting, or a combination of any of these. Staff has concluded that burrows and owl habitat occurs along linear facilities that are confirmed to either support owls and/or support fossorial animals with existing burrows and therefore could support owls and area adjacent to other suitable owl habitat.

An assessment of impacts to burrowing owl should evaluate the type and extent of disturbance, duration and timing of disturbance, sensitivity of the affected owls and visibility of the disturbance, among other environmental factors (CDFG 2012b). The potential for direct impacts to burrowing owls include loss of habitat used for nesting, forage, wintering, and dispersal; loss of nest and satellite burrows; disruption of breeding behaviors during the nesting season; and direct mortality to individual birds. Burrowing owls being ground-dwelling species are more susceptible to being directly crushed or displaced during construction activities. In addition, burrowing owls and other raptors would experience a decrease in prey and food sources due to a decreased number of fossorial mammals from grading and habitat loss.

Construction of the IGCC power plant and linear facilities is estimated to occur over a 42-month window and trenching of the linear facilities, the majority of which will be buried pipelines, would be phased and installed in sections; generally, each linear facility is estimated to take six months to construct. Once the IGCC is constructed, owls in the project area would experience a permanent increased expenditure of energy in order to move around the future power plant and may need to disperse or forage greater distances to other suitable owl habitat, especially since there is a large acreage of alfalfa and other row crops surrounding the project site. Operational noise is likely to permanently impact owls that are likely sensitive to industrial noise levels. These impacts in turn may result in the abandonment of some burrow sites in close proximity to the proposed IGCC power plant or creation of new territories in other suitable habitat areas with low or sparse vegetation and burrowing mammal presence. Nonetheless, since the project occurs in a rural setting and subject to routine traffic along rural roads and agricultural activities and noise levels, burrowing owls have likely habituated to ambient noise levels but would be impacted by increased noise and vibration during project construction and operation. The length of time that habitat would be unavailable to owls for construction of the linear facilities is approximately six months and therefore any owls in the vicinity would be subject to temporary impacts of noise, light, and vibrations, all or a portion of which could occur during the burrowing owl nest season (February 1 to August 31).

Burrowing Owl Mitigation

There is much debate among state, federal, local, and private entities over the most practicable and successful relocation methods for burrowing owl and whether relocation should be considered at all. The California Fish and Game Code Section 1002 does not allow the capture and relocation of burrowing owls unless the effort is associated within the context of scientific research or a Natural Community Conservation Plan (NCCP) conservation strategy (CDFG 2012b). Burrow exclusion or closure (also known as passive relocation) is a technique using one-way doors in burrow openings during the non-breeding season to temporarily exclude owls from burrows and then collapsing the burrow once it has been determined that the owl has vacated the burrow by monitoring or scoping. One reason passive relocation has been criticized as a relocation method is because relocated or displaced owls are tenacious about returning to their familiar burrows and are inclined to move back to the impact site if the impact site is still visible to the owl and/or if the impact site is not completely graded (Bloom pers. comm.). Burrowing owls are put at increased risk when they are introduced to a new environment. No documentation is available to statistically evaluate the success of passive relocation in southern California. Reports elsewhere (Trulio 1995, 1997) do not provide long term analyses associated with passive relocation efforts to determine if passively relocated burrowing owls are present in the area after one or more years. The lack of documented success of passive translocations raises concerns regarding the fate of evicted owls. The demographic consequences of passive relocation and eviction of burrowing owls on an ecosystem level have not been studied and the long-term effects are poorly understood. Therefore, all possible impact avoidance and minimization measures should be implemented and exclusion and burrow collapse can only be recommended as a last option in order to avoid take of burrowing owls (CDFG 2012b).

The previous standard for providing burrowing owl mitigation of 6.5 acres per breeding owl pair is no longer recommended by CDFW because it does not adequately compensate for habitat loss since 6.5 acres was a minimum construction avoidance buffer area around a burrow that was thought to be required by owls (CDFG 2008). Presently, CDFW agency guidance recommends that projects impacting owls and owl habitat should mitigate all significant direct and cumulative impacts to nesting, foraging, wintering, and dispersal habitat during breeding and non-breeding seasons. Land acquisition as project mitigation should be based on the number of acres of all suitable habitat destroyed, with consideration of the number of owls present, duration of occupancy by owls and habitat use of the suitable habitat (CDFG 2008). Acquisition of the appropriate acreage of mitigation lands and determining under which circumstances passive relocation should be considered as a last option for take avoidance, should both take into consideration the foraging distance, average home range of breeding and non-breeding owls, various uses of burrows, and land uses of adjacent lands when determining suitability of those lands to support owls and fossorial mammals.

Construction of the project would result in direct loss of burrowing owl breeding, wintering, and dispersal habitat including all natural, allscale scrub habitat and all developed/disturbed acreage occurring along canals and between agricultural fields. Staff has conservatively estimated that the project would result in direct impacts to approximately 192 acres of burrowing owl habitat (**Biological Resources Table 5**). However, additional indirect and cumulative effects to burrowing owls and owl habitat loss may occur. Indirect effects could include impacts to normal breeding behaviors from project noise, light, vibrations, or alteration of vegetation communities, In addition, staff considers a portion of adjacent habitat lands that would be subject to indirect project effects to be habitat loss for burrowing owl as well. Short or sparsely vegetated areas along the KRFCC and West Side Canal of the proposed processed water pipeline are expected to support burrow or dispersal habitat between adjacent breeding or wintering habitat areas. Depending on the level of farming and crop rotation, crop fields that are left fallow for more than one season likely provide suitable burrowing owl habitat as well. Staff considers these effects to be significant which require mitigation.

The CDFW's current guidance on this species outlines a number of impact avoidance and minimization measures which staff has incorporated into Condition of Certification **BIO-11** (Burrowing Owl Impact Avoidance, and Minimization) including avoiding disturbance of occupied burrows during the nesting period of February 1 through August 31st, avoiding the direct destruction of burrows, implementing a worker environmental awareness program, making burrows to be avoided visible with flagging, eliminating small mammal control in the burrowing owl-occupied areas, among others (CDFG 2012b). Staff's proposed Condition of Certification **BIO-11** also requires the applicant to prepare and implement a Burrowing Owl Monitoring and Mitigation Plan that would incorporate CDFW's (CDFG 2012b) most recent mitigation and impact avoidance guidance for this species. In addition, staff's proposed Conditions of Certification **BIO-11** and **BIO-20** require the applicant to secure off-site mitigation lands that meet habitat criteria for burrowing owl as compensatory mitigation for this species. With the incorporation of the above conditions of certification, the project's impacts to burrowing owl would be reduced; however, until additional data is provided regarding the project's impacts and overall mitigation strategy, staff cannot determine if the project's impacts to burrowing owl would be reduced to below a level of significance.

Other MBTA Birds: Impacts and Mitigation

The Audubon Society has classified 145 Important Bird Areas (IBA) that provide millions of acres of essential habitat for breeding, wintering, and migrating birds including 12 IBAs in Kern County. The project area is located due east of the Buena Vista Lake Bed IBA (Jones et al 2008). The Buena Vista Lake Bed IBA in association with the mosaic of thousands of acres of managed wetlands, freshwater marsh, riparian thickets, grassland, and alkali sink habitats in the areas approximately one to six miles north, south, and east of the project area provide ample habitat opportunities for resident and migrating birds. Several bird species protected by the Migratory Bird Treaty Act (MBTA) and California Fish and Game Codes Section 3503 and 3513 are known to occur in the project area and were observed during various field surveys including many species of songbirds, raptors, and over-wintering shorebirds that utilize agricultural lands as migratory stopover sites. Specifically, the following species have been observed: American kestrel, Cooper's hawk, California horned lark, long-billed curlew, great egret (*Ardea abla*), northern harrier (*Circus cyaneus*), sharp-shinned hawk (*Accipiter striatus*), red-shouldered hawk (*Buteo lineatus*), merlin (*Falco sparverius*), California quail (*Callipepla californica*), Wilson's snipe (*Gallinago delicata*), greater yellowlegs (*Tringa melanoleuca*), lesser yellowlegs (*Tringa flavipes*), killdeer (*Charadrius vociferus*), mourning dove (*Zenaida macroura*), greater roadrunner (*Geococcyx californianus*), thrasher (*Toxostoma* spp.), great-horned owl (*Bubo virginianus*), loggerhead shrike, common raven, rock wren (*Salpinctes obsoletus*), cliff swallow (*Petrochelidon pyrrhonata*), northern rough-winged swallow (*Stelgidopteryx serripennis*), barn swallow (*Hirundo rustica*), Brewer's sparrow (*Spizella breweri*), phoebe (*Sayornis* spp.), white-crowned sparrow (*Zonotrichia leucophrys*), American pipit (*Anthus rubescens*), Bullock's oriole (*Icterus bullockii*), western meadowlark (*Sturnella neglecta*), red-winged blackbird (*Agelaius phoeniceus*), and several other species of warblers, sparrows, finches, and blackbirds (HECA 2012b). In addition, during protocol-level Swainson's hawk surveys, 19 active Swainson's hawk nests and 13 other raptor nests (great-horned owl, red-tailed hawk, and red-shouldered hawk) were found in the project area (URS 2012a, Figure A45-2) and therefore all of these species have been confirmed to nest and forage in the immediate project area. Golden eagles are not known to nest in the project area; however, golden eagles have been observed by local birders and Audubon groups as a transient during migration season (URS 2012c). The various songbird and shorebird species listed above could potentially be impacted from the project due to loss of habitat used for nesting, forage, wintering, and dispersal; loss of nest sites; disruption of breeding behaviors during the nesting season due to construction or operation noise and vibration; and direct mortality to individual birds.

The Central Valley is one of the most important regions in western North America for migratory and wintering bird species. Large expansive acreage of flooded farmlands, managed wetlands, agricultural fields especially rice, and agricultural evaporation ponds provide essential habitat for several species of migratory and wintering shorebirds and songbirds throughout the Sacramento and San Joaquin valleys. Agricultural lands naturally flood during winter months from runoff from primary river systems; many species of birds use the vast acreage of flooded farmlands as migratory stopover sites or wintering cover grounds. Species vary their seasonal, geographic, and habitat use of the Central Valley, primarily in response to changes in water availability from rainfall or management practices of agricultural lands and latitudinal variation in habitat availability mediates, in part, by climate (Shuford et al 1998). For example, in the record rainfall year between 1994 to1995, shorebird numbers increased 74 percent between November and January, primarily from coast-to-interior movements of the dunlin (*Calidris alpina*) and long-billed dowitcher (*Limnodromus scolopaceus)* and local habitat shifts of killdeer (*Charadrius vociferus*)(Shuford et al 1998). These species utilize habitats that occur in the project area such as saltbush scrub, agricultural croplands and farmed fields, stock ponds and flooded seasonal and perennial marshes including the Tule Elk State Reserve and Kern Water Bank as habitat for nesting, foraging, wintering, or as migratory stop-over sites during migration.

The project's potential for impacts to nesting birds is a significant impact under CEQA that requires mitigation. Staff has proposed Condition of Certification **BIO-10** (Mitigation for other MBTA-protected Birds) which requires that the applicant perform pre-construction surveys for birds protected by MBTA and California Fish and Game Codes, establish protective buffers around identified nests, and construction monitoring of nests within construction areas and within 200 foot survey buffer. This measure would apply if any construction activities would occur anytime during the nesting season (February 1 through August 31) during any construction year or start of construction in a previously undisturbed area in order to identify nests that may have begun during the interim. In addition, the applicant has proposed mitigation measures to avoid and minimize impacts to nesting birds, portions of which have been incorporated into staff's proposed Condition of Certification **BIO-6** (Impact Avoidance and Minimization Measures) which requires that construction activities that would result in noise levels greater than 60 decibels be conducted outside of the peak nesting bird season (February 15th to June 15th of any given year).

The loss of bird nests, eggs, or young is regulated by the MBTA and California Fish and Game Code Section 3503 and 3503.5 all of which protect active nests and its contents. In addition and as explained previously, the project's potential for loss of nest tree sites or a decline in nest tree health to the point of reducing successful nesting attempts by nesting birds due to groundwater pumping may constitutue take under MBTA and California Fish and Game Code Section 3503 and 3503.5, and further analysis is required. With the incorporation of the above conditions of certification, the project's impacts to other bird species protected under MBTA and Fish and Game Code Section 3503 and 3503.5 would be reduced; however, until additional data is provided regarding the water supply source and effects of groundwater pumping to nest trees, staff cannot determine if the project complies with these LORS.

Special-status Plant Species

As described previously, seven special-status plant species are known to occur on EHOF as a result of long-term monitoring of the Elk Hills Conservation Area:

- cottony buckwheat (CNPS List 4.2);
- Hoover's eriastrum (CNPS List 4.2);
- gypsum-loving larkspur (CNPS List 4.2);
- Lost Hills crownscale (CNPS List 1B.2);
- Tejon poppy (CNPS List 1B.1);
- oil nest straw (CNPS List 1B.1); and
- San Joaquin bluecurls (CNPS List 4.2).

The 2001 monitoring year marked the last year of comprehensive floristic surveys and consequently, Hoover's eriastrum is the only special-status plants species that is regularly surveyed and monitored at the EHOF. Annual monitoring of changes in Hoover's eriastrum density relative to other vegetative parameters has been conducted on six permanent reference plots distributed throughout Elk Hills since 1993 (Western Kern Environmental Consulting 2012). Two of these species, oil nest straw and

Hoover's eriastrum, have been found in the current carbon dioxide pipeline alignment. These plant species were observed during a single survey performed by OEHI on April 14, 2011 and the number of individual plants observed or a figure showing their location along the pipeline were not provided by the applicant. Additional surveys are needed and additional location data is needed for the observed populations of oil nest straw and Hoover's eriastrum plant as well as the occurrences of other plant species listed above in order to determine the impacts of the project on special-status plants. All species listed above have a high likelihood of occurring within the carbon dioxide pipeline alignment and to a lesser extent plant species identified in **Biological Resources Table 3**.

An occurrence of an additional CNPS List 3.2 plant species, vernal barley (*Hordeum intercedens*), was documented during wetland delineation surveys performed at the northern end of the natural gas pipeline route near Site 1; vernal barley was estimated to comprise approximately 40 percent of the absolute vegetative cover in the low-lying areas where it was observed and it is expected that similar low-lying areas may support this species (URS 2012a). Vernal barley is described as occurring in coastal dune scrub, vernal pools, and valley and foothill grasslands from approximately sea level to 3,000 feet elevation (CNPS 2013). The Consortium of California Herbarium lists 145 records of this species most of which occur in San Diego, Los Angeles, Riverside, Orange, and Ventura counties and one record from Kern County (south of SR 119 and east of I-5 in mixed annual grassland/chenopod scrub habitat during 1995, CCH 2010). As a CNPS List 3.2 plant species, this species is considered fairly endangered in California and staff considers this species locally rare since it is not commonly known from Kern County. Therefore, project impacts to this species would be significant.

No other special-status plant species have been observed within any other project linear alignment; however, sufficient focused botanical surveys have not been conducted due to lack of site access or insufficient rainfall years. Plant surveys were conducted on March 27 through 30th, 2012 in portions of the project area that are not currently farmed although these surveys were performed in conjunction with wetland delineation surveys and not following the standard plant survey protocol (CDFG 2009). Sites 1, 2, 3 and 5 located along the natural gas pipeline route were not surveyed due to property access restrictions and only portions of Site 4 and non-farmed areas along the railroad spur were surveyed in March 2012 (URS 2012a). This incidental observation of CNPS List 3.2 plant species, vernal barley, near Site 1 of the natural gas pipeline indicates that these sites and other linear facilities have the potential to support additional rare plant species and focused botanical surveys following protocol (CDFG 2009) are warranted.

Construction and Operation Impacts to Special-status Plants

Individual plants could be crushed or damaged by vehicle traffic, equipment or destroyed by grading, pipeline trenching, or other site preparation work. Seedbanks of these plants could also be destroyed or buried. Indirect effects include population fragmentation and disruption of gene flow; potential impacts to pollinators; increased risk of fire; herbicide drift; and disruption of photosynthesis and other metabolic processes from fugitive dust during construction and operation of the project. These special-status plant species could also be directly and indirectly affected by changes in hydrology due to re-contouring or redirecting of natural drainage flow or direct removal of irrigation channels or drainages. This is primarily a concern along the carbon dioxide pipeline route located south of the California Aqueduct where ephemeral drainages may occur. Since the applicant has not provided a Streambed Alteration Agreement application or provided information on the occurrence of drainages in the area of the proposed carbon dioxide pipeline alignment, staff cannot determine if these types of indirect effects to rare plants would occur. Additionally, wildfires (caused by construction or downed transmission lines) are rare but do occur and exotic species often frequent burned areas following a wildfire. Other impacts that occur from the project during construction and operation could occur to surrounding vegetation communities from grading activities creating air-borne, fugitive dust, sedimentation, and erosion, which can lead to compaction and decline of surrounding vegetation.

Hoover's Eriastrum

Hoover's eriastrum was federally listed as threatened in 1990 and has subsequently been removed from the Federal Endangered Species Act threatened species list as a result of many new occurrences between 1986 and 1997. Prior to 1986, this species was known from only 19 sites in four counties primarily from low-elevation, hillier intermixed annual grassland and saltbush scrub regions of the western San Joaquin Valley floor. Hoover's eriastrum has since been discovered in San Benito and Kings counties and in numerous additional locations of the four original counties. Presently, most of the occurrences are from four metapopulations including: 1) Kettleman Hills in Fresno and Kings counties; 2) Carrizo Plain-Temblor Range region of Santa Barbara and San Luis Obispo counties; 3) Lokern-Elk Hills-Coles Levee – Lost Hills region of western Kern County; and 4) Antelope Plain-Semitropic area in Kern County (USFWS 1998). Presently, Hoover's eriastrum is a CNPS List 4.2 plant species indicating it is of limited distribution and on a CNPS's Watch-list. This species continues to be threatened primarily by urban development and agricultural conversion. Hoover's eriastrum was observed during a single survey performed along the proposed carbon dioxide pipeline alignment on April 14, 2011 but a map showing the locations or population size estimate was not provided.

The Recovery Plan (USFWS 1998) indicates that since Hoover's eriastrum occurs on hillier slopes many of which are oil fields, that petroleum production does not pose a threat in most cases but could be detrimental if larger areas of occupied habitat were disturbed. Recovery strategies for this species includes protecting existing populations of a minimum size of 40 acres from incompatible uses assuming habitat conversion on the Kern Valley floor will continue, protecting unoccupied suitable habitat with buffers to allow for annual population fluctuations between years, and long-term monitoring, habitat management, and reporting.

Oil Nest Straw

Oil nest straw is a CNPS List 1B.1 species indicating it is seriously threatened in California with a high degree of threat (CNPS 2013). In addition, it is globally ranked as G2 indicating it is imperiled (6 to 20 element occurrences or 1,000 to 3,000 individuals in existence). In petroleum-producing areas, this species occurs on flatlands and hillier slopes generally from 200 to 1,000 feet elevation. Historically, there were five known populations of oil nest straw, four of which were in Kern County in the vicinity of

Bakersfield, McKittrick, and Taft (USFWS 1998). Oil neststraw is currently only known from Elk Hills and Coles Levee Preserve; the status of other oil-producing areas in western Kern County are unknown and undocumented. On Elk Hills, this species has been on 61 sections since floristic surveys began in 1995 (Quad Knopf 2001) and was found to be most prevalent in the northwestern and southeastern portions of the EHOF. The Elk Hill's oil neststraw population represents a single metapopulation (USFWS 1998). There are ten records of this species in the Consortium of California Herbaria, eight of which are from Kern County and two of which are records from the Naval Petroleum Reserve in Elk Hills (CCH 2010). Given this species' high degree of threat in California and known occurrences in the Elk Hills region, staff considers this species to be regionally rare and restricted in its geographic range, a portion of which occurs in the project area on the EHOF. Therefore, a substantial loss or impact to an oil nest straw population from construction and operation of the HECA project could be a significant impact to this species since its geographic range is restricted in California and threats to existence are high. The conservation strategy identified in the Recovery Plan (USFWS 1998) for this species includes protecting at least five distinct populations of the five extant occurrences presently known of this species. The metapopulation of oil neststraw at Elk Hills represents one of the required five populations for protection and to prevent extinction or extirpation of the species.

Staff needs additional botanical survey data for the carbon dioxide pipeline alignment in order to determine the level of impact of the project on this locally rare plant species that occurs on Elk Hills. Because the Elk Hills metapopulation is one of five known remaining populations, the plants identified during April 2012 surveys along the carbon dioxide route must be avoided during grading and construction of the pipeline route. Without further information of this occurrence and others along the pipeline route as well as special-status plant species occurrences along the natural gas pipeline route (Sites 1 through 5), staff cannot determine the project's impacts or compliance with LORS for this biological resource.

Special-status Plant Mitigation

The applicant has proposed several impact avoidance and minimization measures for special-status plant species (HECA 2012b). Staff believes that the successful implementation of the applicant's proposal to avoid impacts to special-status plants would depend on the applicant's incorporation of CDFW's rare plant survey protocols (CDFG 2009) and the applicant's ability to identify all locations for special-status plant species prior to project disturbance.

Staff's proposed Condition of Certification **BIO-17** requires the applicant to prepare a Revegetation Plan which would include a discussion of revegetation methods and goals taking into consideration a phased construction schedule of linear routes; performance standards and timeline for meeting success criteria; methods for salvaging the seed bank of annual species, storing topsoil, and preserving germplasm for use in revegetation areas; methods for controlling invasive weeds and weed management measures in revegetation areas; contingency parameters if success criteria are not met; and a long-term monitoring and reporting schedule during construction and operation. Establishing the goals in the Revegetation Plan is of utmost importance since shrub cover and percent ground cover can influence the presence of wildlife prey and predator abundance. Since dense shrub areas can attract kit fox predators such as coyotes, it is preferred that areas subject to revegetation be planted with low-growing herbaceous grassland species which is suitable habitat for kangaroo rat, ground squirrels, and other small mammals, a good prey base and essential habitat element for San Joaquin kit fox, burrowing owl, and other wildlife. A habitat reclamation study for endangered species performed at the EHOF evaluated revegetation success on disturbed sites for the purpose of reducing erosion and restoring carrying capacity of habitat for endangered species and their prey (Hinshaw et al 1999). In this study, revegetation was considered successful when a site's vegetative cover at the end of a growing season was greater than 70 percent of the average cover observed at reference sites and after five years, 47 percent of revegetation sites met this criterion. After the first two years of monitoring, annual grasses comprised most of the cover and after four years, shrubs comprised most of the plant cover. Lagomorphs and small rodent populations stabilized by the second year and use of the reclaimed sites by kit fox, coyotes, and bobcats slightly increase three to four years following treatment. Since reclaimed sites appeared to favor kit fox predators (such as coyotes and bobcats) once more shrubs became established and given the high costs of revegetation and monitoring of the study, the effectiveness of habitat reclamation for endangered species at EHOF was poor. In summary, if disturbed areas are going to be subject to revegetation for the HECA project, staff believes shrub density must be monitored and maintained at low enough levels as to not favor kit fox predators in revegteation areas.

The applicant has indicated temporary disturbance areas along Highway 58 associated with the natural gas pipeline including Site 1 and Sites 2 through 5 pending landowner approval would be subject to post-construction revegetation and monitoring activities (Biological Resources Figure 2, URS 2012c). Depending on the level of maintenance (vehicle traffic) required along linear facility maintenance roads and existing habitat disturbance levels, staff believes the following areas should also be considered for revegetation activities:

- Any entry and exit pits used for HDD that would not revert back to active farmland;
- Any portion of the buried pipelines (carbon dioxide, natural gas, processed water, potable water) that would not be used as a permanent maintenance road; and
- the carbon dioxide pipeline alignment since this facility would impact disturbed, natural allscale scrub lands.

In order to determine species-specific impacts of the project on special-status plants, additional focused botanical surveys, data, and mapped occurrences are needed along the carbon dioxide pipeline route and Sites 1 through 5 of the natural gas pipeline following CDFW's 2009 protocol (CDFG 2009) in order to identify the locations and number of plants that would be directly or indirectly impacted by the project. Staff's proposed Condition of Certification **BIO-17** (Special-status Plant Species Impact Avoidance Measures) requires the applicant to perform preconstruction focused botanical surveys prior to beginning work in suitable habitat areas that are previously undisturbed, identifying any populations in construction zones and on construction drawings as Environmentally Sensitive Area, and other site design modifications.

Implementation of staff's above listed conditions of certification would benefit all special-status plant species and sensitive vegetation communities by minimizing disturbance areas. Given the status of Hoover's eriastrum as a CNPS List 4.2 Watch-list, increasing but fluctuating trends on EHOF, and other known localities of this species on Coles Levee Preserve and Buttonwillow, staff believes the potential for impacts to Hoover's eriastrum would be reduced to less than significant levels with the incorporation of **BIO-4**, **BIO-5**, **BIO-6**, and **BIO-17**. Staff believes that with the incorporation of the above conditions of certification, impacts to most common and special-status plants would be reduced and minimized where possible; however, staff cannot determine if the project's impacts to oil neststraw, vernal barley, and potentially other special-status plants would be reduced to less than significant levels due to insufficient botanical baseline data on the occurrence of special-status plants in the project areas. Other special-status herbaceous annuals with a moderate to high likelihood to occur along project linear routes that could have been missed due to the lack of focused botanical surveys following agency protocol (CDFG 2009) include but are not limited to cottony buckwheat, Tejon poppy, and San Joaquin bluecurls.

PROJECT IMPACTS TO SENSITIVE VEGETATION COMMUNITIES

Staff believes that one CNDDB record for valley sink scrub occurs in the vicinity of the processed water pipeline and proposed well field. This record is described as roughly 325 acres in size and occurs northwest of Highway 58 near the KRFCC. The mapped area is characterized by *Atriplex spinifera*, *A. polycarpa*, *Suaeda moquini*i with non-native herbaceous grasses and forbs (CDFG 2012). In addition, small patchy sections of riparian habitat occur west of the proposed well field and processed water pipeline. Several Swainson's hawk, other hawk nests, and common raven nests that could be utilized by nesting raptors occur in these trees along the KRFCC and West Side Canal. If these patchy riparian and valley sink scrub habitats are supported by shallow groundwater or other sub-surface water flows through adjacent irrigation canals, continuous pumping for the project could cause a gradual decline of these nest trees and more analysis is required. Staff considers the potential long-term, indirect impacts to these vegetation communities a potentially significant CEQA impact due to a dramatic decrease in occurrence and range of these communities in the southern San Joaquin Valley.

Although water supply to the root system of nest trees and valley sink scrub in the project area are believed to be sourced by irrigation runoff in agricultural canals, more data and analysis is needed on the baseline groundwater levels and water use of these sensitive vegetation communities that occur in the project area. If water drawdown is consistent enough over the course of several years, staff believes the decrease in water supply to these vegetation communities could result in gradual decline, an alteration in biotic community structure or composition, or failure. In preparation of the FSA/FEIS, staff needs additional information on the baseline water supply and water use of sensitive vegetation communities in this area in order to determine the level of significance of project impacts to sensitive vegetation communities.

Impacts to Waters of the State and Waters of the United States

HECA conducted pre-survey investigations and field surveys, including a significant nexus determination for potential Waters of the United States. The estimated boundaries and areas of jurisdictional features within the project area were based on current regulations, written policies, and guidance from the Corps. The applicant delineated a total of 187.91 acres of water features in the project area, of which a total of 92.51 acres were delineated as waters of the U.S. including portions of the West Side Canal/Outlet Canal; Kern River Flood Control Channel; East Side Canal; California Aqueduct; several agricultural ditches, canals, and stock ponds that connect to these features; and depressional wetland areas (URS 2012a, URS 2013c). Since the Corps has not issued a Jurisdictional Determination for the project to date, the Corps' regulation of these delineated features under Clean Water Act Section 404 is unknown at this time. A 250-foot buffer from all project areas was used to define the potentially impacted areas. The KRFCC was identified as Waters of the U.S.- 54, of which approximately 87.88 acres could potentially be affected by the project. The estimated acreage reflects the portion of the KRFCC that is within the 250-foot buffer area of the project areas associated with the processed water pipeline and carbon dioxide pipeline. These features may also be subject to CDFW Fish and Game Code Section 1600 jurisdiction. The applicant has submitted a request for a Jurisdictional Determination to the Corps and a Section 1600 Notification of a Lake or Streambed Alteration Agreement application to CDFW (URS 2013c, 2013d); however, the extent of Corps and CDFW jurisdiction over the project is unknown at this time.

A depressional area that ponded water long enough to support western spadefoot toad tadpoles was identified between the Outlet Canal and California Aqueduct, which indicates depressional wetlands that support sufficient wetland hydrology occur in the project area. Sufficient wetland hydrology in a depressional area may also indicate that hydric soils and hydrophytic vegetation have become established over time in these depressional areas; however only the Corps can determine the occurrence of jurisdictional wetland or other Waters of the U.S. in the project area. Direct impacts that could occur to potential jurisdictional waters include inadvertent fill or grading during construction activities. Indirect impacts could occur during construction and operation of the project including contamination of nearby irrigation ditches, drainages, and other waterways from stormwater runoff, impacts to water quality from changes to hydrology or inadvertent release of drilling fluids during HDD activities, increased rates of erosion, and changes in vegetation community due to hydrological alterations, among others.

The applicant has proposed to avoid all potentially state and federally jurisdictional waters by using HDD underneath these features including the point where the carbon dioxide pipeline would cross under the California Aqueduct, Westside/Outlet Canal, and KRFCC (HECA 2012b). All entry and exit pits for HDD would be located outside of the identified potential waters of the U.S. HDD is a surface launched, guided, and steerable drilling system used for the trenchless installation of pipelines and avoids direct impacts to the water courses and other sensitive features such as highways, railroads, airport runways, and pipeline corridors by drilling underneath these features. The HDD process includes a drilling rig that would bore a horizontal hole under the water crossings. The depth of drilling and depth of cover varies depending on the physical and geotechnical parameter of the feature being drilled under; however, the minimum separation between the bottom of a canal channel and the top of the drilling pipe is 25 feet and the maximum depth for linear installations at proposed HDD crossings is 100 feet. Each entry pit for HDD would temporarily impact approximately 120 feet by 100 feet and HDD exit pits would be approximately 75 by 100 feet in size (URS 2012b). The applicant has indicated that depending on the canal specific hydrologic conditions at the time of the work, an assessment will consider whether HDD or conventional open cut methods would be used. When possible, crossings of canals would be performed when the canal is dry and not holding water (URS 2012b). CDFW has indicated that HDD activities under water conveyance features would require a California Fish and Game Code Section 1600 Streambed Alteration Agreement and preparation of a frac-out plan. During May 2013, the applicant submitted a draft HDD Plan (including a frac-out plan) for the proposed HDD activities in conjuction with the notification package to CDFW for a Lake or Streambed Alteration (URS 2013d). The applicant submitted a Jurisdictional Delineation report for the HECA project and a Nationwide Permit 33 Preconstruction Notification during March 2012 (URS 2013c) which staff has preliminarily reviewed and will completely review upon preparation of the FSA/FEIS. The applicant has requested authorization for the temporary fill of 0.20 acre of non-wetland Waters of the U.S.from the Corps under Nationwide Permit 33 (Temporary Construction Access, (HECA 2012b). For a complete discussion of the existing setting and project impacts to surface waters, see the **Soil & Surface Water** section of this PSA.

In order to minimize or avoid the potential for impacts to potentially jurisdictional waters during construction, staff has proposed Condition of Certification **BIO-19** which includes standard streambed impact avoidance measures that are typical of Lake or Streambed Alteration Agreements issued by CDFW and a requirement to update and finalize the draft HDD Plan that was previously submitted. The applicant has delineated potential state waters that occur within the project area (URS 2013d). Several braided ephemeral drainages are apparent upon review of aerial photography and the carbon dioxide pipeline route transverses these drainages. Staff believes these drainages may fall under California Fish and Game Code Section 1600 jurisdiction. OEHI has indicated they hold a 12-year site-wide streambed alteration maintenance agreement with CDFW as required by 1601 and 1603 of California Fish and Game Codes (OEHI 2013a); however, the applicant and OEHI have been unable to provide a copy of the maintenance agreement. Therefore, implementation of **BIO-19** would assist in minimizing impacts to state waters; however, staff needs additional information on the occurrence of potential waters of the state occurring along the proposed carbon dioxide pipeline route in order to determine the level of significance of project impacts to state waters. Implementation of **BIO-19** would minimize the impacts of the project to potential state waters as well as potential Waters of the U.S. However, until the Corps issues a Jurisdictional Determination for the project and CDFW determines the extent of 1600 jurisdiction over the project, staff cannot determine if project impacts to Waters of the U.S. and state waters would be reduced to less than significant levels.

Other Construction Impacts

Noise

Animals rely on hearing to avoid predators, obtain food, and communicate. Excessive construction noise could disrupt the behaviors of several special-status species by interfering with normal communication, potentially interfering with maintenance of contact between mated birds, obscuring warning and distress calls that signify predators and other threats, and affecting feeding behavior and protection of the young. Behavioral and physiological responses to noise and vibration have the potential to cause injury, energy loss (from movement away from noise source), a decrease in food intake, habitat avoidance and abandonment, and reproductive losses (Hunsaker 2001; National Park Service 1994). Alert distance refers to the distance between an animal and an activity when the animal becomes visibly alert. Flush initiation distance, also called flight distance, refers to the distance between the animal and an activity when the animal takes flight (Taylor and Knight 2003). The species-specific alert and flush initiation distances are unknown for the species most likely to be found nesting within the project area and likely vary considerably among species based on flock size, time of year, time of day, distance to refuge, and other unknown factors (Blumstein et. al 2002).

As discussed previously, a fenced tule elk herd occurs at the Tule Elk State Reserve located less than one mile east of the project site. The project would not result in any direct impacts to tule elk or habitat; however, potential indirect impacts could occur to this elk herd and all wildlife species during project construction, specifically unsilenced steam blows and pile driving, and operation; for elk, the potential for indirect noise impacts could occur more prominently during two sensitive time periods for tule elk, during the rut season (roughly June through November) and calving season (roughly March through July) which could result in a disruption of breeding behaviors (Pers. comm. California State Parks). The increased energy costs of movement, escape, and stress caused by frequent and unpredictable disturbance may be detrimental to elk calf growth (Kuck et al 1985). North American elk have also been known to become habituated to human activities and disturbance as evidenced in more urbanized area in the Rocky Mountains in parts of Montana. Avoidance and attraction are responses to negative stimuli or positive rewards. Habituation occurs when animals stop responding to repeated activities that are not accompanied by positive or negative reinforcement (Thompson and Henderson 1998). Likewise, if the human activity is predictable and harmless to elk and does not prove detrimental to their daily activities, elk can be readily domesticated and can habituate to human activity (Thompson and Henderson 1998).

Project construction activities would generally begin at 6:00 AM on a five- day week basis and would result in a short-term, temporary although relatively long-term (approximately 42 months) increase in the ambient noise level (HECA 2012b). Equipment used during the construction process will differ from phase to phase. In general, heavy equipment (bulldozers, dump trucks, and concrete mixers) will be used during excavation and concrete-pouring activities. Most other phases involve the delivery and erection of the equipment and building components. Studies have shown that noise levels over 60 A-weighted decibels (dBA) can affect the behavior of certain bird species (Dooling and Popper 2007).

For construction of the linear facilities, the loudest construction activities are associated with pile driving. Kangaroo rats are especially sensitive to loud construction noise and vibrations and OHV activity has been known to rupture the auditory bullae of kangaroo rats (pers comm., Julie Vance). Construction noise levels at 50 feet from the project site boundary to the nearest sensitive receptor are predicted to range from 60 dBA (pickup trucks) to 101 dBA (pile driving). Due to sound propagating, construction noise levels are expected to attenuate to a range of 40 to 81 at approximately 480 feet from the site boundary (HECA 2012b, Table 5.5-18, Individual Equipment Noise Levels Generated by Project Construction). Several sensitive receptors were evaluated for the noise analysis and staff is focusing on sites LT-2/ST-2 and ST-4, since these sites are located on the west and north side of the Tule Elk State Reserve, respectively. Baseline noise levels at LT-2/ST-2 and ST-4 are estimated to be 48 and 45 dBA, respectively. The highest site-average sound levels (89 to 91 dBA) are associated with foundation and site clearing phases of the construction (HECA 2012b). For the two sensitive receptor locations along the Tule Elk State Reserve listed above, construction of each linear facility was estimated to generate a range of 45 to 60 dBA of noise.

Construction of the transmission line would consist of installing footings, poles, insulators and hardware, and pulling conductors and shield wires. Construction of the transmission line may require pile driving although it is expected that any piles required for transmission line construction would be augured; however, if pile driving is needed to install power line poles, pile driving activity noise levels could range from 45 to 72 dBA along the transmission line route (HECA 2012b, Tables 5.5-22 through 5.5-25). Construction of the potable water/transmission line facility is the facility most likely to cause indirect impacts to tule elk and other wildlife since this facility would be located immediately north of the Tule Elk State Reserve. For a complete analysis of operational noise impacts, refer to the **Noise and Vibration** section of this PSA.

During the final construction phase, a method used to clean piping and testing called “steam blows” creates substantial noise. The intent of the steam blows is to heat and sweep the piping systems to remove any debris or fine particles that could damage the steam turbine generator or other equipment. Each steam blow is followed by a cool-down period. The heating and cooling cycles are expected to last 2 or 3 hours each, and will be performed several times daily over a period of 2 or 3 weeks. The applicant proposes to employ temporary silencing systems to minimize these short-term, temporary noise impacts during steam blows since typical steam blow silencing should be able to reduce noise levels by 20 dBA to 30 dBA at each receptor location (HECA 2012b); as a result, estimated silenced steam blow noise levels at LT-2/ST-2 would range from 62 to 72 dBA and would range from 58 to 68 dBA at ST-4 (HECA 2012b, Estimated Silenced Steam Blow Noise Levels). Staff concludes the potential for impacts to wildlife present at the Tule Elk State Reserve due to loud construction noise would be significant and mitigation is required. To minimize the impact of steam blows, pile driving, and other loud construction activities over 60 dBA, staff has incorporated into Condition of Certification **BIO-6** (Impact Avoidance and Minimization Measures) a requirement that if these activities are required, they must occur outside of the peak calving season (February 15th to June 15th) which also incorporates the peak nesting bird season.

Conducting focused wildlife surveys prior to the start of ground-disturbing activities per staff's proposed conditions of certification **BIO-7, BIO-8, BIO-9**, **BIO-10**, **BIO-11**, **BIO-12**, **BIO-13**, **BIO-14, BIO-15,** and **BIO-16** would ensure that no nesting birds, San Joaquin kit fox, American badger, blunt-nosed leopard lizard, listed small mammals, western spadefoot toad, giant garter snake or other special-status or common wildlife are present or in the immediate vicinity of the site during construction. Specifically, songbird nests will be identified within 200 feet of the project boundaries and a minimum construction avoidance buffer of 0.50 mile from active Swainson's hawk nests would be implemented per Conditions of Certification **BIO-9** and **BIO-10**. Staff believes that with the incorporation of these measures as well as **BIO-6**, the potential for indirect effects to the tule elk herd, nesting birds and other wildlife would be reduced to less than significant levels.

Noxious Weed Spread and Fugitive Dust

Construction activities and soil disturbance could introduce new noxious weeds to lands adjacent to the power plant site and linear facilities and could further spread exotic plant species already present in the vicinity. The spread of invasive plants is a major threat to biological resources because non-native plants can displace native plant communities, increase the threat of wildfire, and supplant wildlife foods that are important to herbivorous species. Bermuda grass (*Cynodon dactylon*), erodium, Mediterranean barley (*Hordeum marinum*), fescue (*Vulpia* spp.), Mediterranean grass, Russian thistle (*Salsola tragus*), red brome and many more exotic plant species are already present in the project area and are expected to increase as a result of construction- and operation-related disturbance. Following construction, exotic plant species are characteristically opportunistic and could occupy disturbed soils within areas that have recently been disturbed and spread into adjacent vegetation communities, primarily along linear transmission line and pipeline routes.

Disturbance of the soil's surface caused by construction equipment and other activities would result in increased wind erosion of the soil. Dust can have deleterious physiological effects on plants and may affect their productivity and nutritional qualities. The destruction of plants and soil crusts by dust exacerbates the erosion of the soil and accelerates the loss of nutrients (Okin et al. 2001). Soil erosion from construction activities and vehicle activity, which affects vegetation and soil properties, could have an adverse effect on many special-status plant and wildlife species that are known to occur in the project area.

Staff considers these impacts to be significant and require mitigation. Measures to implement during construction of the power plant site and linear facilities to control the spread of noxious weeds have also been incorporated into staff's proposed Condition of Certification **BIO-6** (Impact Avoidance and Minimization Measures) such as requiring that all construction vehicles and equipment be cleaned at truck wash facilities and inspected by a Biological Monitor before entering the project site or construction area, use of certified noxious weed-free straw or hay bales for erosion control, and use of manual, mechanical, and use of herbicides to control the spread of exotic weeds. Measures to control dust and soil erosion have also been incorporated into **BIO-6** such as applying non-toxic soil binders and establishing initial stabilized ground surfaces within 21 days following construction disturbance. It is important to note that any herbicide use for the project would need to conform to current USFWS policy at the time of use and would be determined during Section 7 consultation for the project; no use of any pesticide or herbicide would be permitted without prior consultation and approval from the USFWS. Moreover, staff has required that the project's WEAP (**BIO-4**) and BRMIMP (**BIO-5**) specifically include parameters to prevent the spread of noxious weeds during construction of the project. With the incorporation of these conditions of certification, the project's impacts to the spread of noxious weeds and fugitive dust and the effects on habitat alteration would be reduced to less than significant levels.

Other Operational Impacts

Potential operation-related impacts include impacts to birds due to collision with and/or electrocution by the transmission line and disturbance to wildlife due to increased noise and lighting.

Operational Noise

The project site would be located in a relatively open, non-habituated agricultural area. The western boundary of the Tule Elk State Reserve is approximately one mile east of the project site which staff considers a sensitive noise receptor. Excessive noise during operation of the project could disrupt breeding and calving behaviors of the tule elk herd. Also, loud operational noise could disrupt breeding and mating behaviors of nesting birds and other wildlife. The sum of the project's operational noise contribution and existing ambient noise at LT-2/ST-2 and ST-4 is expected to range from 30 to 37 dBA (HECA 2012b, Table 5.5-30 Summary of Project Contributions with Noise Control Features). These levels are below the typical studied threshold of 60dBA for indirect impacts to nesting birds and other wildlife. Therefore, staff concludes there will be no significant impacts to biological resources by increased operational noise and no additional biological resource mitigation is proposed. For a complete analysis of operational noise impacts, refer to the **Noise and Vibration** section of this PSA.

Avian Collision and Electrocution

The tallest structures and features associated with the construction of the power plant would include the following (measured as feet above grade): the gasification structure (305 feet), air separation column can (200 feet), AGR methanol wash column (235 feet), and the feedstock barn(160 feet) (HECA 2012b, Figure 2-6 Project Elevations). A proposed 2-mile electrical transmission line will interconnect the project site to a future PG&E switching station and the power generated by the project would be connected to the PG&E system by a new single-tower, 230-kV transmission line. This single-circuit line would connect to a new switchyard at the project site.

Birds are known to collide with transmission lines, exhaust stacks, and other structures, causing mortality to the birds. Bird collisions with power lines and structures generally occur when a power line or other structure transects a daily flight path used by a concentration of birds and these birds are traveling at reduced altitudes and encounter tall structures in their path (Brown 1993). Collision rates generally increase in low light conditions, during inclement weather, during strong winds, and during panic flushes when birds are startled by a disturbance or are fleeing danger. Collisions are more probable near wetlands, within valleys that are bisected by power lines, and within narrow passes where power lines run perpendicular to flight paths (APLIC 1996).

Raptors, and other large aerial perching birds, are susceptible to transmission line electrocution if they simultaneously contact two energized phase conductors or an energized conductor and grounded hardware. This happens most frequently when a bird attempts to perch on a transmission tower or pole with insufficient clearance between these energized elements. The majority of bird electrocutions are caused by lines that are energized at voltage levels between 1-kV and 60-kV, and “the likelihood of electrocutions occurring at voltages greater than 60-kV is low” because phase-to-phase and phase-to-ground clearances for lines greater than 60-kV are typically sufficient to prevent bird electrocution (APLIC 2006). The proposed HECA transmission line would be 230-kV; therefore, phase-to-phase and phase-to-ground clearances are expected to be sufficient to minimize bird electrocutions.

To avoid potential electrocution and collision from transmission lines, staff requires in Condition of Certification **BIO-6** (Impact Avoidance and Minimization Measures) that the transmission lines are constructed in accordance with Avian Powerline Interaction Committee (APLIC) guidelines specifically designed to reduce the risk of bird electrocution. Specifically, the phase conductors shall be separated by a minimum of 60 inches and bird perch diverters and/or specifically designed avian protection materials should be used to cover electrical equipment where adequate separation is not feasible (APLIC 2006). With implementation of this condition of certification, the potential for electrocution and collision impacts to birds would be reduced to less than significant levels.

Operation Lighting

Lighting plays a substantial role in collision risk because lights can attract nocturnal migrant songbirds and major bird kill events have been reported at lighted communications towers (Manville 2001) with most kills from towers higher than 300 to 500 feet (Kerlinger 2004). Many of the avian fatalities at communications towers and other tall structures have been associated with steady-burning, red incandescent L-810 lights used at communications towers that seem to attract birds (Gehring et al. 2009). Longcore et al. (2008) concluded that use of strobe or flashing lights on towers resulted in less bird aggregation, and, by extension, lower bird mortality, than use of steady-burning lights. Night lighting can also alter foraging and breeding behaviors of nocturnal mammals, reptiles, amphibians, and other wildlife. Existing night lighting in the area is scattered and generally limited to the few residences that occur in the project area. The few major sources of night lighting in the region include oil extraction operations in the Elk Hills and an existing fertilizer facility. Overall, the region is primarily dark with numerous light sources that while visible, do not tend to light the night sky significantly (HECA 2012b).

Lighting that is not required continuously during nighttime hours will be controlled with sensors or switches such that lighting will be on only when needed. In addition, structures and transmission towers will be treated to reduce sun reflectivity and reduce potential glint/glare and high-pressure sodium vapor fixtures will be used which produce low-intensity amber light during nighttime hours (HECA 2012b). The project's lighting system would provide power plant personnel with illumination in both normal and emergency conditions; the system would primarily consist of alternating current (AC) lighting and direct current (DC) lighting for activities or emergency egress required during an outage of the project's electrical system. The project's lighting would be designed to directionally orient, shield, and hood lighting to minimize off-site migration of light (HECA 2012b). While the project may slightly add to existing lighting, the project will not significantly contribute to ambient night lighting in the project area due to the design features discussed above. With the incorporation of these design measures into the project's lighting plan and implementation of staff's Condition of Certification **BIO-6** to minimize lighting impacts which would be monitored and reported on during construction, staff concludes there will be no significant impacts to wildlife from the night lighting associated with operation of the new facility.

Retention Ponds

To allow for stormwater drainage and reclaimed water testing, nine retention ponds are proposed within the project site; the ponds range in size from 0.26 acre to 3.07 acres and four would be lined (URS 2012b). The length of time the ponds would hold water varies, but for a 10-year stormwater flow scenario, basin water drawdown ranges from 1.8 to 28.7 days; however, the Kern County Engineering, Surveying, and Permit Services department has retention basin design standards which require that retention basins fully drain within 7 days (Kern County Development Standards, Division 4 Standards for Drainage, Chapter 8); therefore, the applicant would need to consult with Kern County on retention basin design if the basin would hold water beyond the 7 day requirement. For a complete discussion on retention pond design and county design requirements, see the **Soil & Surface Water** section of this PSA/DEIS.

Stormwater that is separated to collect for testing for contaminants and potential re-use, poses a threat to wildlife in the project area, particularly migrating or wintering waterfowl. A report for the San Joaquin Valley Drainage Implementation Program indicates that a variety of waterfowl and shorebirds can seasonally inhabit or utilize ponds for resting, foraging during migration, and nesting resulting in indirect impacts from high selenium or hyper-saline conditions and high total-dissolved-solids concentrations (EPTC 1999). Potential impacts to wildlife exposed to high concentrations of selenium from operation of evaporation ponds bioaccumulation of selenium by waterbirds from ingestion of a variety of organisms used as food resources such as macroinvertebrates, egg shells, and tissue; increased mortality; reduced reproductive success growth or condition, and exposure to elevated concentrations of water quality constituents including, but not limited to salts. Wildlife species inhabiting areas adjacent to the evaporation basins are susceptible to potential indirect adverse effects since several large mammals, raptors, and other predators may forage on wildlife that utilizes ponds providing a trophic pathway for exposure of these wildlife species to evaporation basin constituents (EPTC 1999). This report goes on to say that management of evaporation basins were regulated by waste discharge requirements in the past, until studies by USFWS revealed adverse impacts to wildlife occurring at evaporation basins in the Tulare Lake Basin which prompted CDFW to develop measures to reduce the impacts to wildlife consisting of the following measures:

minimum water depth of 2 feet, levee slopes as steep as practicable, vegetation control, no construction of exposed windbreaks, disease surveillance and control program, invertebrate sampling, and hazing (EPTC 1999).

Staff believes that allowing stormwater to pond in retention basins for extended periods longer than 24 hours, especially for the larger retention ponds could act as an attractant to waterfowl or shorebirds, given the high amounts of over-wintering and migrating birds that occur in the project area primarily during winter months. In order to minimize birds and other wildlife from entering the ponds and exposure to hypersaline waters and other contaminants, staff has incorporated into Condition of Certification **BIO-10** (Mitigation for other MBTA-protected Birds) a requirement for the applicant to apply netting over the retention ponds, monitor, and report monthly on the effectiveness of the exclusion netting.

Nitrogen Deposition

Atmospheric nitrogen (N) alters the structure and function of terrestrial ecosystems because nitrogen is often the limiting nutrient in many soils and ecosystems throughout California. Nitrogen oxides (NOx) and ammonia (NH_3) can be deposited directly to the ground or undergo chemical and phase transformation in the atmosphere and be deposited from tens to thousands of kilometers from the source (CEC 2007). Nitrogen-poor soils and nitrogen-sensitive plant communities are often more susceptible to detrimental effects of nitrogen saturation including decreased plant function due to leached nutrients from the soil or a decrease in symbiotic mycorrhizal fungi (CEC 2007). Mechanisms by which nitrogen deposition can lead to impacts on sensitive species include direct toxicity, changes in species composition among native plants, and enhancement of invasive species (Fenn et al. 2003; Weiss 2006a).

The major documented impact of N-deposition on California terrestrial biodiversity is to increase growth and dominance of invasive annual grasses in low biomass ecosystems primarily coastal sage scrub, serpentine grassland, and desert scrub and to a lesser extent vernal pools and sand dune ecosystems (CEC 2007).

In a research study on the *Impacts of Nitrogen Deposition on California Ecosystems and Biodiversity* (2007) prepared for the Energy Commission, several California natural communities were mapped and modeled using Forest Research and Protection (FRAP) to assess nitrogen deposition. The east side of the San Joaquin Valley and lower Sierra Nevada foothills receive from 5 to 9 kg of N per hectare per year; the west side of the San Joaquin Valley and adjacent slopes of the Inner Coast Ranges experience 3 to 4 kg of N per hectare per year (CEC 2007).

Staff uses a 6-mile radius to evaluate the direct nitrogen plume impacts of power plants. It is staff’s experience that by the time the plume has traveled this distance, in-plume concentrations become indistinguishable from background concentrations. Staff considers the sensitive biological resources that could be impacted by the nitrogen deposition plume within 6 miles of the project site the following: Tule Elk State Reserve and portions of the Kern Water Bank, Coles Levee Ecoystem Preserve, EHOF, and the Lokern Ecological Reserve (Biological Resources Figure 1). These natural areas are considered sensitive as described under the ‘Regional Setting’ subsection of this

PSA/DEIS. Staff believes that given the sources of NOx emissions from the proposed project, the project's nitrogen deposition plume could affect these areas and potentially others along linear facilities. Nitrogen deposition modeling has not been performed to date, although modeling will be performed in preparation of the FSA/FEIS. Therefore, the potential for the project to affect sensitive biological resources from nitrogen deposition are unknown at this time.

OEHI Component of HECA

The following section provides an analysis of the environmental effects of the OEHI component of HECA to biological resources in accordance with the California Environmental Quality Act. Where significant impacts have been identified, staff has provided recommended mitigation measures to the applicable permitting authorities in order to reduce an impact to biological resources to less than significant levels.

This environmental analysis has been prepared assuming the OEHI component would consist of the following:

- Construction of 720 proposed wells (309 injection wells and 411 production wells). OEHI has designed the project to utilize existing wells to the maximum extent feasible and it is estimated that 570 of the 720 wells necessary for the CO_2 EOR project would utilize pre-existing well locations. The remaining 150 wells would be new installations;
- Construction of a new CO_2 EOR processing facility which includes a central tank battery, water treatment plant, reinjection compression facility, and carbon dioxide recovery plant (approximately 60.61 acres of impact)(URS 2013b);
- Installation of an estimated total length of 652 miles of new pipelines, much of which would be located in existing pipeline corridors that are sited on disturbed acreage. Pipeline routes would range in right-of-way size from 40 to 59 feet wide; and
- Construction of an estimated 13 new CO_2 EOR satellite gathering stations estimated to range in size from 1.1 acres to 2.6 acres each (URS 2013b). Nine of the 13 satellite gathering stations are proposed for the southeastern portion of the EHOF in disturbed, high oil production areas (referred to hereafter as the nine proposed southeastern satellites). The four remaining satellites are proposed for lands on the northwestern flank of the EHOF (referred hereafter as the four proposed northwestern satellites) in areas of lower oil production in areas immediately adjacent to various mitigation parcels of the Elk Hills Conservation Area.

Results of Biological Field Surveys

OEHI has performed various wildlife and botanical surveys along the proposed carbon dioxide pipeline route, proposed EOR processing facility, and first three satellite locations. OEHI performed protocol-level blunt-nosed leopard lizard (BNLL) hatchling surveys between August 24, 2012 and September 14, 2012 along the proposed carbon dioxide pipeline route and proposed EOR processing facility within the southeastern section of Section 27 South and no BNLL were observed during these surveys.

However, 2 burrowing owls, 5 potential owl burrows, 11 giant kangaroo rat precincts, and 6 San Joaquin antelope squirrels were observed within the survey area during those surveys. Also, several hundred observations of side-blotched lizard (*Uta stansburiana*) were identified indicating the habitat is suitable for supporting reptiles such as BNLL. OEHI performed two additional reconnaissance-level biological surveys on December 4 and December 6, 2012 within the three test satellite locations that would be constructed during the demonstration period of the OEHI component during which loggerhead shrike was the only special-status species observed (OEHI 2013b).

Staff notes that the area surveyed during biological surveys did not cover the entire Phase 1 injection pattern for the three proposed satellite locations identified in OEHI's Class II Underground Injection Control (UIC) permit application provided to the Energy Commission, which identified a much broader area being impacted by injection wells and pipelines (OEHI 2012c). On the EHOF, these field surveys of the three satellite locations covered portions of Sections 35 South and 3G whereas the UIC Class II permit identified the Phase 1 injection area including the installation of injection wells, production pipelines, and injection pipelines covering the two above referenced sections as well as Sections 33 South, 34 South, 4G and 2G which were not surveyed. Consequently, staff does not consider these biological surveys complete or conclusive; however, the results do give an understanding of sensitive biological resources that occur in the Phase 1 injection areas.

Summary of 2011 Elk Hills Conservation Area Monitoring Survey Results

During 2011 monitoring of the Elk Hills Conservation Area by Western Kern Environmental Consulting (2012), San Joaquin kit fox were rarely identified along the Skyline Road during nighttime spotlight surveys and scent stations, a method used to attract animals to a scented area in order to look for footprints to indicate animal presence or absence in an area. Since Skyline Road bisects EHOF from east to west through high oil production areas, this may indicate that San Joaquin kit fox utilize high oil production areas for night movements. However, kit fox visitation was most frequently identified along the north flank scent station lines during spring and fall survey periods. Kit fox were observed frequently along the northern but more frequently along the southern flank Buena Vista Valley route and no natal dens were identified on the entire EHOF during 2011 monitoring.

The northern flank survey route recorded the greatest number of kangaroo rat observations with 217 sightings during the spring survey period; the most burrowing owl incidental observations were along the northern flank as well. San Joaquin antelope squirrel was the listed mammal most frequently encountered in high oil production areas; however, kangaroo rat species were the most frequently captured small mammals during small mammal trapping and during 2011 trapping efforts, short-nosed kangaroo rat was the most frequently trapped mammal. During the fall, the northwestern flank route had the highest recorded kangaroo rat observations with 23 sightings. Giant kangaroo rat was the most frequently identified species during the 2011 field surveys near the proposed four northwestern satellites. The highest number of active giant kangaroo rat precincts was recorded along the northwestern portion of Elk Hills and adjacent lands in Sections 11Z, 12Z 13Z, and 14Z where a total of 1,328 precincts were identified, immediately west of the proposed four northwestern satellites.

Most of the BNLL observations were along the southern Buena Vista Valley survey route. No BNLL were identified along the north flank driving route in 2011, although five BNLL were observed along the north flank during walking surveys. Hoover's eriastrum is the only special-status plant species that is routinely monitored in Elk Hills Conservation Area. Annual monitoring results indicate that the mean density of Hoover's eriastrum increased on three of six monitoring sites since last year, including Section 7R which is located within the area of the proposed four northwestern satellites.

Construction Impacts to Habitat and Special-status Species

Staff primarily reviewed OEHI's existing USFWS Biological Opinion, California Endangered Species Act Memorandum and Take Authorization including two amendments (URS 2012d, OEHI permitting documents) and Appendix A of the HECA project's Amended AFC (HECA 2012b, Appendix A), among other sources in determining the effects of the proposed project's actions. The following discussion provides an overview of the direct and indirect impacts to biological resources that are expected to occur with the development of the proposed project.

Construction of new wells, conversion of existing wells, and trenching and installation of over 650 miles of new pipeline within existing pipeline corridors would result in direct impacts to special-status plant and wildlife species and staff considers these impacts significant. During construction activities, individual kit foxes, blunt-nosed leopard lizards, and kangaroo rats may be directly injured or killed by vehicle strikes from construction-related traffic, through inadvertent crushing or entombment in collapsed dens or burrows, or entrapment in construction area trenches. During project grading and trenching activities kangaroo rat burrow systems, namely giant kangaroo rat precincts, could be destroyed, vegetative food sources removed, and soil conditions could become more compacted making it difficult for small mammals to burrow. Because BNLL inhabit washes, this species is more vulnerable to accidental wastewater discharges and oil spills. Individual plants and plant populations could be crushed or damaged by vehicle traffic or destroyed by grading, pipeline trenching, or other disturbances. Seed banks of special-status plants may be buried or otherwise destroyed. Other impacts that may occur during construction or operations include wildfires or contact with oil spills or sumps. Operational impacts to these same species include dust and direct mortality from routine vehicle maintenance traffic among other activities. Additionally, individual wildlife may be subject to impacts from increased levels of human disturbance, including increased noise and vibration. Some wildlife may be able to escape direct mortality or injury but may be displaced to adjacent areas making these animals vulnerable to increased predation, exposure, and stress through loss of cover sites.

In general, construction of the nine southeastern satellites are proposed for disturbed, high oil production areas where staff considers the overall biological value of habitat lands to be low, simply due to higher levels of disturbance from oil production; however, this does not preclude the occurrence of special-status plants and wildlife in these locations and in fact, several special-status wildlife species are known to occupy these areas. The four northwestern satellites are proposed for lands generally in lower oil production areas along the northwestern flank of the Elk Hills and provide much higher biological values to special-status plants and wildlife given their adjacency to Elk Hills

Conservation Areas and lower level of disturbance from oil production on the northern flank of Elk Hills. Based on a large number of precincts identified in the location of the four proposed northwestern satellites during 2011 monitoring surveys, staff believes giant kangaroo rat would likely be impacted by ground disturbance from the development of satellites in this area. However, staff recognizes that small mammal populations naturally fluctuate from year to year based on rainfall levels and vegetation growth. Kangaroo rats are especially sensitive to loud construction noise and vibrations and off-highway vehicle noise activity has been known to rupture the auditory bullae of kangaroo rats. Staff believes grading and drilling for new well casings would significantly impact the large number of kangaroo rat precincts and other ground-dwelling species presently identified in this area.

The four northwestern satellites are proposed for an area where a Hoover’s eriastrum population is known to occur. Following 2011 monitoring surveys, the density of Hoover’s eriastrum was 21.17 plants per square foot, a substantial increase in this population since this population’s density was zero following 2007 monitoring surveys. The Recovery Plan *(*USFWS 1998) indicates that since Hoover’s eriastrum occurs on hillier slopes many of which are oil fields, that petroleum production does not pose a threat in most cases but could be detrimental if larger areas of occupied habitat were disturbed and identifies a recovery strategy for this species of protecting existing populations of a minimum size of 40 acres from incompatible land uses. However, staff believes it is likely unfeasible to avoid or preserve a 40-acre portion of natural lands that supports Hoover’s eriastrum, given the site plan provided for the proposed four northwestern satellites. Oil nestraw was observed during April 2011 field surveys along the proposed carbon dioxide pipeline route indicating other special-status plant populations likely occur along the north flank. The Elk Hill’s oil neststraw population represents a single metapopulation and the Recovery Plan (USFWS 1998) identifies the metapopulation of oil neststraw at Elk Hills as one of the five populations that requires protection in order to prevent extinction or extirpation of the species.

OEHI has indicated the project would result in a total of approximately 261.6 acres of permanent disturbance and 1,447 acres of temporary disturbance upon construction of the entire OEHI component including the installation of 150 new wells, construction of 13 satellite stations, and new pipeline routes. OEHI has also indicated 570 existing wells would be converted for project use, but has not described or included acreage disturbances for this work associated with the proposed project. Staff believes this construction could result in substantial additional disturbance to natural lands and loss of habitat values and these impacts have not been included in the disturbance acreages. Each satellite gathering station is estimated to have a permanent surface footprint of 230 by 200 feet (approximately 1.056 acre each) including a surrounding 500-foot survey buffer (OEHI 2013b).

OEHI has indicated that construction of the first three satellites would impact 63.79 acres of disturbed ruderal habitat on EHOF during DOE’s demonstration period (URS 2013b). These impacts include 60.61 acres of impact from the estimated 1,200 feet by 2,200-foot CO_2 EOR facility and 3.17 acres of impact for construction of the 3 satellite gathering stations. However, this acreage conflicts with a larger area that is identified as the Phase 1 demonstration period in OEHI’s Class II UIC permit application which shows a broader disturbance area being impacted for injection and production pipelines.

Therefore, it is unknown whether 3.17 acres of impact for each satellite gathering station includes impacts associated with the construction of approximately 25 injection patterns including 34 offsetting production wells as well as injection and production pipelines represented in OEHI's Class II UIC permit application (OEHI 2012c). In summary, staff believes the permanent disturbance acreage identified in **Biological Resources Table 9** below does not include impacts and ground disturbance associated with the conversion of 570 existing wells.

Biological Resources Table 9:
Project Impacts to Natural Ruderal Lands[6]

Project Component	Project Quantity	Acres Disturbed	Type of Disturbance
New Well Installations (130' x 280' = 0.84 acres/well)	150	126	Permanent
Conversion of existing wells	570	Not provided	Permanent
CO2 EOR Processing Facility	1	101.8[7]	Permanent
CO2 EOR Satellite Stations (2.6 acres each)	13	33.8	Permanent
4-Inch Diameter Buried Pipelines (40 foot wide right of way)	777,057 linear feet	714	Temporary
6-Inch Diameter Buried Pipelines (59 foot wide right of way)	63,903 linear feet	87	Temporary
12-Inch Diameter Buried Pipelines (4 foot wide ' right of way)	261,019 linear feet	282	Temporary
16-Inch Diameter Buried Pipelines (47 foot wide right of way)	19,122 linear feet	21	Temporary
18-Inch Diameter Buried Pipelines (59 foot wide right of way)	54,852 linear feet	74	Temporary
26-Inch Diameter Buried Pipelines (59 foot wide right of way)	199,656 linear feet	270	Temporary
Total Permanent Disturbance = 261.6 Acres			
Total Temporary Disturbance = 1,447 Acres			

[6] These acreages were developed from HECA Amended AFC, Volume 2, Appendix A-1 (HECA 2012b).

[7] The acreage of the CO2 EOR processing facility (101.8 acres) provided in HECA 2012b conflicts with the acreage of the CO2 EOR processing facility (60.61 acres) provided in URS 2013b, Section 7 Biological Assessment, Table 6.

San Jouaqin Kit Fox Presence on EHOF

The remaining San Joaquin kit fox population is fragmented and constitutes a metapopulation of three large core populations and less than ten small sub-populations. The largest extant population of San Joaquin kit fox occurs from Elk Hills and the Buena Vista Valley in western Kern County and the Carrizo Plain Natural Area in San Luis Obispo County (USFWS 1998), one of the three large core populations identified in the Recovery Plan. Therefore, movement within and around Elk Hills and connection with other sub-populations in western Kern County is essential to promoting gene flow and preventing local extirpations to the greatest extent possible. Both developed sites including the Naval Petroleum Reserves in California (NPRC including NPR-1 and NPR-2) and oil fields around McKittrick, and undeveloped sites, primarily the Lokern Natural Area, have been subject to several long-term San Joaquin kit fox population studies. In a San Joaquin kit fox population dynamics study of a 216-square mile study area on NPRC from 1980 to 1995, kit fox abundance varied widely and ranged from 46 foxes in 1991 to 363 in 1994. Kit fox population dynamics appeared to vary closely related to the availability of primary prey species, rabbits (leporids) and kangaroo rats (Cypher et al 2000). Variation in prey availability, particularly kangaroo rats, produced significant and often rapid changes in kit fox abundance. Kit fox density and population growth on NPRC was strongly related to precipitation patterns although precipitation did not directly affect kit fox, but it more directly affected primary productivity by reducing food and cover of prey populations, which is typical in arid ecosystems like the southern San Joaquin Valley. Similar results were documented at Camp Roberts and on the Carrizo Plain where kit fox population declines were attributed to declining prey availability during periods of below-average precipitation (Cypher et al 2000).

Predators, mostly coyotes but also some bobcats (*Lynx rufus*), were the most frequent cause of adult and juvenile kit fox mortality on NPRC. Cypher et al (2000) concluded that although populations of coyotes and kit foxes on NPRC appeared to be inversely related in the early 1980s, populations of both species closely tracked each other from 1985 to 1995 indicating that other factors (such as food availability) was influencing each population. Interestingly, the Cypher et al study (2000) concluded that coyotes seem to predate on San Joaquin kit fox on NPRC as exploitative competition and not predation for food which was consistent with findings of an Energy Commission study that indicated that coyotes rarely consumed the foxes they killed and coyote attacks of kit foxes were more likely the result of competitive exclusion. The 15-year study performed by Cypher et al (2000) also concluded that oilfield activities also had minimal effects on the San Joaquin kit fox population. Relatively few foxes died as a direct result of oilfield activities on NPRC; of the 712 recovered dead kit foxes, 43 died from oilfield-related causes, 35 of the 43 were hit by vehicles on NPRC roads and the others either drowned or were entombed in oil facilities during the 15-year study period. This same study concluded that individual foxes on NPRC used an average of 11.8 dens each year and over 1,000 dens were found on NPRC; therefore, the availability of denning habitat did not appear to be a limiting factor. Cypher et al (2000) also concluded kit foxes were often observed around oilfield equipment and activities and when dens were found, dens were often times in man-made structures (pipes, culverts) on NPRC. Space use and den use patterns of kit foxes did not appear to be affected by oil activities; nightly movements and home range parameters were similar in developed and undeveloped areas of NPRC (Cypher et al 2000). Spiegel et al (1991) studied developed sites (oil fields) and undeveloped sites (Lokern Natural Area) in western Kern County denning, foraging, and concluded that home ranges ranged from 1.36 to 6.66 square km (0.76 to 2.57 square mile) in undeveloped plots. Nightly movements on the Elk Hills Naval Petroleum Reserve averaged 9.6 miles during the breeding season, which are much longer than the average nightly movement of 6.3 miles during the pup-rearing season and the pup-dispersal season, 6.5 miles (USFWS 1998). In general, kit foxes are able to adapt to oilfield activities, are able to persist in areas of development, and appear to be tolerant of human activity. This same study concluded that the most significant direct effect of oilfield activities to the San Joaquin kit fox population on EHOF is habitat loss due to facility construction, which reduces carrying capacity.

Impacts to San Joaquin Kit Fox

Staff believes that with the implementation of the OEHI component of HECA, the direct and indirect effects to San Joaquin kit fox along with the loss of an estimated 261 acres and 1,447 acres of permanent and temporary impacts to San Joaquin kit fox habitat, respectively, would significantly impact this species and mitigation is required. OEHI estimates that each year the OEHI component would create 36 wells, consisting of either new well installations or conversion of existing wells, for approximately 20 years (HECA 2012b, Appendix A). Staff believes this would result in a substantial long-term construction impact over the course of 20 years. As the project is phased and the location of satellites is determined for project UIC permitting, certain habitat areas would be unavailable for use by kit fox and all wildlife during construction depending on the locations of any new well and pipeline installations and well conversions. Phasing of the project over a 20-year construction window could substantially hinder the movement of the local Elk Hills kit fox population as well as regional movement between other sub-populations. This impact would be especially significant during the breeding and dispersal seasons and may affect nighttime foraging distances and dispersal patterns of adults and young of the year. As outlined above, studies indicate that the primary predictor of kit fox population trends is the abundance of prey (kangaroo rats and rabbits primarily) which in turn is driven by precipitation and therefore prey species abundance can vary considerably from year to year. Therefore, the OEHI components's effects to the Elk Hills small mammal populations would directly influence the San Joaquin kit fox population dynamic over the course of 20 years of construction.

The Cypher et al (2000) study concludes that long-term monitoring is essential to follow kit fox population variability and land management strategies should focus on land management activities that would conserve viable populations during unfavorable environmental conditions. The current biological permits require the long-term population monitoring of the Elk Hills Conservation Area as well as setting aside additional conservation lands prior to the impacts occurring. Staff has recommended mitigation measures to minimize the potential for significant impacts to special-status species as outlined in the “Recommended Mitigation Measures” section.

Operational Impacts

Greenhouse Gas Emissions and Potential for Carbon Dioxide Leaks

The following section discusses the potential for carbon dioxide leakage during operation of the OEHI component and effects of greenhouse gas emissions on soil and vegetation. Carbon capture and storage technology includes two basic approaches: 1) carbon dioxide gas is captured directly from large and stationary source points, and then transported through pipelines (such as the HECA power plant) and injected into geologic storage sites far below the ground surface known as carbon capture and storage (CCS), and 2) atmospheric carbon gas is biologically fixed by growing vegetation (e.g. forest trees, biomass crops, etc) and stored in aboveground and belowground plant parts, referred to as carbon sequestration (CS) (Patil 2012) and the CCS and CS processes complement each other. CCS technology is being increasingly considered as a mechanism that can contribute to reducing the carbon dioxide emissions over the next 50 years. Carbon dioxide is an odor less and non-toxic gas; however, exposure to high concentrations poses danger to human beings, animals, and the surrounding environment. Since typically in CCS systems the carbon dioxide is captured from large production sites and transported through pipelines over long distances, the first point of leakage would be pipeline failure, small leaks from joints or pipeline corrosion; therefore, pipelines require continuous surveillance and monitoring. The potential for leakage from geologic storage sites may occur from failure of the sealing cap of the injection well or migration of gas through geologic media. If there were slow yet large leaks, there are chances that a continuous release from CCS sites could go unnoticed since leaking carbon dioxide gas would quickly diffuse in the atmosphere. When it comes to the long-term safety of CCS technology, there are uncertainties on the long-term fate and safety of large volume of carbon dioxide gas to be injected into geologic formations (Patil 2012); however, with OEHI's sophisticated monitoring system in place as described below, the likelihood of a carbon dioxide leak occurring and going un-noticed is low.

OEHI has indicated the likelihood of carbon dioxide leakage from sequestering activities is low for a number of reasons. On July 23, 2010, OEHI submitted a Monitoring, Reporting, and Verifying Plan (MRV Plan, OEHI 2010) which provides details on how the wells and an existing sophisticated system of monitoring equipment would be centrally monitored and controlled. This monitoring system would include monitoring for CO_2 leakage and would offer an added level of monitoring to ensure early detection and control of potential leaks. The MRV Plan included several components for monitoring leakage of injected carbon dioxide such as risk assessment of leakage and determining sequestration volumes. Staff concludes that it is feasible to inject the projected amount of carbon dioxide over 20 years into the Stevens reservoir and the potential for carbon dioxide leakage from the OEHI component is low. Given the geologic lifetime of natural carbon dioxide domes, and many long-lasting carbon dioxide injection projects, it is likely that the carbon dioxide would be stored permanently in the EHOF. OEHI would intensively monitor injection and production wells for any sub-surface and surface carbon dioxide leakage in several ways. Staff further concludes that the injection pressures required for this project are below pressures required to fracture the formation and would not induce significant seismic events. For a complete analysis of the impacts of the proposed project, see the **Carbon Sequestration And Greenhouse Gas Emissions** section of this PSA/DEIS.

Although there is minimal potential for leakage of carbon dioxide along well casings, the OEHI component would still emit significant levels of carbon dioxide during various construction and operation activities. The OEHI component's greenhouse gas (GHG) emissions include the direct onsite emissions from EOR Processing Facility processes and the indirect onsite emissions from power consumption, as well as emissions from onsite ancillary and auxiliary equipment and from material and personnel transportation. The onsite emissions sources include the following sources:

- EOR Project Power Consumption (indirect)
- CO_2 Injection Heater
- Regeneration Gas Heater
- Triethlylene Glycol (TEG) Reboiler
- Amine Unit
- Central Tank Battery (CTB)
- Reinjection Compression Facility (RCF)
- Fire Pump Engines
- Piping Fugitives

As described in the **Carbon Sequestration And Greenhouse Gas Emissions** section of this PSA/DEIS, the offsite emission sources include material and worker transportation. Over 75 percent of the onsite GHG emission total is indirectly emitted that accounts for the OEHI component's power consumption. The OEHI component requires moving of the injection and production wells periodically, corresponding new or repurposed pipeline work, and new well drilling. Therefore, construction of this project is ongoing for the twenty-year life of the project. The annual average emissions of the OEHI component over the course of 20 years of construction is 4,330 metric tonne of carbon dioxide with over 99 percent of this coming from on-road and off-road combustion sources during construction. Operation of the proposed OEHI component would cause GHG emissions from a number of onsite and offsite sources including the EOR Project Power Consumption, CO_2 Injection Heater, Regeneration Gas Heater, Triethlylene Glycol (TEG) Reboiler, Amine Unit, Central Tank Battery (CTB) Flare, Reinjection Compression Facility (RCF) Flare, Fire Pump Engines, Piping Fugitives, and materials and employee vehicle trips. The annual average emissions of the OEHI component during operation is 339,976 metric tonne of carbon dioxide.

Effects of GHG Emissions on Soils and Vegetation

Atmospheric carbon is naturally exchanged between reservoirs and sinks (known as the carbon cycle) of which the terrestrial environment, generally vegetation and soils, are known to store, absorb, or sequester and eventually exchange carbon. A recent study in the Mojave Desert found that desert soil ecosystems represent a carbon sink possibly as a result of biotic crusts, vegetation, alkaline soils, or an increase in average precipitation (Campbell et al 2009). Existing vegetation, including above ground biomass and below ground plant roots that would be cleared for the installation of solar power plants and IGCC plants, including those like the HECA project would destroy biotic crusts (photosynthetic cyanobacteria, algae, lichens, and mosses), remove alkaline soils, and release any stored carbon that was in the soil (Campbell et al 2009).

Studies have shown that high carbon dioxide levels have changed the botanical composition of the world's grasslands, farms, and urban landscapes by increasing the growth, reproduction, and survival of some plant species more than others. One study reported that high carbon dioxide levels are favoring cool-season grasses over warm-season grasses and weedy shrub over native forage grasses, which are less suitable forage types for livestock grazing (USDA Agricultural Research Service 2009). This same report also concluded that high levels of carbon dioxide increase the water-use efficiency of plants and primarily benefit the development of weedy shrubs and cool-season grasses by partially closing the leaves' stomates and conserving water. Another study concluded similar results indicating that while carbon dioxide levels are the high, plant stomates shrink which cause less water release and lower evapotransporation rates, a direct warming trend and link to global warming (Carnegie Institution 2010). Two key causes of invasions of fast-growing weedy plants were found to occur, an escape from natural enemies and an increase in plant resources, which favor non-native species that have adapted to environments rich in nitrogen, water, and carbon dioxide; when these non-native plants from Europe end up in the United States, a resource-rich environment without natural enemies, they easily outcompete fast-growing native plants. In conclusion, fast-growing weeds are the type of plant most favored by global change (USDA Agricultural Research Service 2009).

An increase in soil carbon dioxide concentrations in near surface and below- ground canopies could have significant effects on the above-ground vegetation, soil-inhabiting micro-organism and organic matter by suppressing root respiration, altering plant water/nutrient uptake capacity and soil pH, and ultimately effecting the above-ground biomass and photosynthetic capacity of vegetation. A study at the Artificial Soil Gassing and Response Detection (ASGRD), an experimental field facility, was implemented where carbon dioxide was artificially injected into soil plots to simulate build up gas concentrations and its slow release to the soil surface into experimental, individual plots of pasture grass, commercial turf, and fallow lands and an equal number of control plots of each crop type (Patil 2012). The study concluded that even low levels of carbon dioxide gas injection (one to three liters) significantly increased the soil carbon dioxide concentrations in a very short period of time by displacing soil oxygen levels and adversely affected the growth of pasture, turf grass, and establishment of winter bean crop. This study also showed that different plant species tolerated soil carbon dioxide concentration levels and grasses tended to be more tolerant compared with beans and other broad-leaved species. The study also indicated that some of the more sensitive plant species (non-grassy species) could be used to grow along the path of CCS pipelines and monitored for growth and effects as an early detection warning system of leaks. A limitation of this short-term study was overall low injection rate and shallow depths of injections in comparison to the long-term injection schemes of CCS technology. Therefore, while the ASGARD site studies increased the industry's knowledge and understanding of the effects of below ground carbon dioxide leaks on soils, long-term studies to evaluate the potential long-term consequences on ecosystems are needed (Patil 2012).

Soils are mainly affected by pollutant emissions through leaching of particulate contaminants and removal of gases by precipitation, followed by surface deposition. The adsorption rate of soils is dependent on the distance from the source, the concentration of the pollutant, soil properties, hydrological situations, and meteorological conditions (HECA 2012j). The soil types at the EHOF include the Cajon, Elk Hills, Kettleman, Kimberlina, Lokern, and Bitterwater soil series and Excelsior soil variant. Except for the Lokern series, all soil series including the Excelsior soil variant are considered deep, moderately well drained coarse, loamy soils that formed on alluvial fans and low stream terraces; the Lokern series is classified similar to the above soils but is a somewhat more poorly drained soil (USDA 1988). Staff believes these soils are expected to have lower sorption capacities for carbon dioxide and other greenhouse gases since these soils are classified as well drained with high runoff. Staff concludes that although the potential for direct leaks of carbon dioxide are low along the proposed carbon dioxide pipeline and well casings, the project’s contribution to high levels of carbon dioxide during operation could significantly affect soil and vegetation over time. Staff believes that given the existing high level of disturbance of natural habitats on the EHOF and dominance of non-native plant species, any immediate effects of the OEHI’s component greenhouse gas air emissions would be minimal although the incremental effects of implementation of the OEHI component on soil and vegetation resources could be significant.

Staff’s Recommended Mitigation Measures

Presently, there are no adopted Habitat Conservation Plans or Natural Community Conservation Plans on the EHOF; however, OEHI presently implements an Endangered Species Mitigation Program in accordance with 1995 USFWS Biological Opinion, CESA 2081 Incidental Take Permits and addendums. The EHOF has already been the subject of Federal Endangered Species Act Section 7 consultation and is currently being operated in compliance with a 1995 Biological Opinion issued by the USFWS and a related 1997 Memorandum of Understanding (MOU) for a California Endangered Species Incidental Take Permit (CESA ITP) between OEHI and CDFW which has been amended twice and remains in effect until the year 2014 (URS 2012d). The earlier Section 7 consultation was undertaken in connection with the Supplemental Environmental Impact Statement/Program Environmental Impact Report for the federal government’s sale of the Naval Petroleum Reserve (OEHI 2012d). A key component of this program is the performance of pre-activity surveys prior to any ground disturbing activity. Other impact avoidance and minimization measures include but are not limited to, the presence of biological monitors during ground disturbance, a litter control program, speed limits in construction areas, avoiding and destruction of burrows including minor relocation of project facilities, and continued long-term monitoring of the Elk Hills Conservation Area. Compliance with the 1995 USFWS Biological Opinion and the 1997 CDFW MOU has been documented in annual and semi-annual monitoring reports submitted to USFWS since 1998 (URS 2013b).

OEHI reinitiated consultations with USFWS and CDFW in 2002 to support a 50-year Section 10 Habitat Conservation Plan (HCP) for all production operations at the EHOF. However, staff is unclear whether the 50-year permit would cover all future OEHI oil and gas activities including the work associated with the OEHI component of HECA and the 13 proposed satellite injection patterns. OEHI anticipates the new HCP being approved by the end of 2013. OEHI anticipates that the Biological Opinion and MOU would be replaced by new Section 10 and Section 2081 permits supported by the HCP at some point in the future. The CDFW is presently the lead agency for the CEQA document being prepared for issuance of the Section 10 HCP.

Staff understands that DOGGR would be the permitting authority over future development phases of the OEHI component of HECA; therefore, project-specific CEQA analyses would be conducted as future phasing of the OEHI component are submitted to DOGGR for permitting. Staff recommends that DOGGR and other subsequent permitting authorities of future phased components of the OEHI component adopt the conservation strategies and conservation measures identified in either the existing biological permits (URS 2012d, OEHI biological permitting documents) or as amended in the subsequently adopted OEHI Section 10 HCP and subsequent CEQA analyses.

CUMULATIVE IMPACTS

A project may result in a significant adverse cumulative impact where its effects are cumulatively considerable. "Cumulatively considerable" means that the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects (Cal. Code Regs., tit. 14, § 15130). Cumulative impacts must be addressed if the incremental effect of a project, combined with the effects of other projects is “cumulatively considerable” (14 Cal. Code Regs, § 15130(a)). Such incremental effects are to be “viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects” (14 Cal. Code Regs., § 15164(b)(1)). This cumulative impact analysis makes a broad, regional evaluation of the impacts of past, currently proposed, and future projects that threaten plant and wildlife communities within the southern San Joaquin Valley.

The size of the San Joaquin Valley floor below 500 feet elevation covers approximately 3.44 million acres. The valley extends westward up into the foothills to approximately 3,000 feet elevation and supports natural and man-altered plant communities. Four urban areas (Stockton, Modesto, Fresno, and Bakersfield) and eight smaller urban centers (Lodi, Tracy, Manteca, Turlock, Merced, Madera, Hanford-Lemoore, and Visalia) occupy the San Joaquin Valley floor. Less than 150,000 acres or 5 percent of the valley floor remains uncultivated with most of the undeveloped lands in the foothill regions. Significant portions of land not cultivated or urbanized has been developed for petroleum extraction, strip-mined for clay, or occupied by roads, canals, oil storage facilities, pipelines, or evaporation ponds (USFWS 1998). The southern San Joaquin Valley has experienced substantial losses of habitat and reduction of species due to past urban, industrial, and agricultural development. The San Joaquin Valley floor’s original natural lands have mostly been tilled or developed, so that by 1979 only 6.7 percent of the original natural lands south of Stanislaus County remained (USFWS 1998). Of over 5.2 million acres in the southern San Joaquin Valley region that were studied by the Energy Commission (including the Carrizo Plain Natural Area and most of the Tulare Basin below the woodland belts), approximately 800 acres of degraded wetlands were found in 1989 with over 100,000 acres of seasonal wetlands occurring farther north near Modesto and Merced (USFWS 1998).

Several multispecies Habitat Conservation Plans (HCP) are in various stages of plan development including the Metropolitan Bakersfield HCP (MBHCP Steering Committee 1994), San Joaquin County HCP (SJMSCP 2000), and the draft Kern County Valley Floor HCP (Garcia and Associates 2006). The Energy Commission has conducted two large-scale natural community and species survey efforts, the Southern San Joaquin Valley Ecosystem Protection Program (largely surveyed lands in the Tulare Basin) and quarter-sections surveys that were later conducted on the Carrizo Plain Natural Area; both of these programs collectively provided more extant biotic community and habitat distribution information than all others combined (USFWS 1998). Other habitat conservation efforts in the southern San Joaquin County include the following, but are not limited to: Carrizo Plain Natural Heritage Program; the Bureau of Land Management's Lokern Area of Critical Environmental Concern, the Center for Natural Land Management's (CNLM) Lokern Ecological Preserve in the Lokern Natural Area, several Energy Commission mitigation programs; CDFW mitigation program in Allensworth Natural Area; the endangered species habitat protection programs on Occidental of Elk Hills; Kern and Pixley National Wildlife Refuge programs; and several mitigation banks including Aera Energy's Coles Levee Ecosystem Preserve, the Kern Water Bank, and Chevron Lokern HCPs, all of which are located in Kern County. The Lokern Ecological Preserve is part of the larger, Lokern Natual Area (LNA) which includes over 40,000 acres of high-quality habitat for various imperiled wildlife and plant species of the San Joaquin Valley and is located west of the HECA project.

For the purposes of determining the geographical scope of this biological cumulative impact analysis, staff considered the portion of the planning area of the Recovery Plan (USFWS 1998) that occurs in Kern County in determining the project's cumulative impacts to biological resources since the majority, if not all, special-status plant and wildlife species impacted by HECA are covered species in the Recovery Plan. Generally, the planning area addressed in the Recovery Plan includes the San Joaquin Valley, Carrizo and Elk Horn Plains, and parts of the Cuyama, Salinas, Sacramento, and other valleys. Furthermore, since HECA is proposed for the southern-most portion of the Recovery Plan area and the species potentially impacted are valley floor to lower foothill species, staff utilized the Kern County Planning and Community Development Department's list of discretionary projects in determining the scope of projects that would likely be approved and/or constructed in the foreseeable future. Staff focused on development projects proposed on the valley-floor to lower elevation plain areas roughly between the Tehachapi Mountains to the east and the Temblor Range to the west.

Kern County has identified the following 25 solar projects as approved or proposed on the Kern County valley floor which staff has assumed would directly affect the same biological resources as HECA upon development:

- Chevron Energy Solutions (18 acres, Conditional Use Permit);
- Meadows Field Solar (9 acres, Conditional Use Permit);

- Renewable Technology Development (2 acres, Conditional Use Permit);
- Lost Hills Solar Project by NextLight – an application for a General Plan Amendment, cancellation of a Williamson's Act contract, and Conditional Use Permit for a photovoltaic (PV) solar facility on 370 acres of land located near Lost Hills, Kern County, California;
- Maricopa Sun Solar Complex Project by Maricopa Sun LLC – an application for a General Plan Amendment, Conditional Use Permit, Tentative Parcel Map, and cancellation of a Williamson Act contract on 6,046 acres for PV solar facilities and 2,000 acres for future solar facilities near Taft, California;
- SKIC Development Inc (321 acres, Conditional Use Permit);
- Lerdo Detention Facility Expansion Project by Kern County General Services (14 acres, Conditional Use Permit);
- RE Distributed Solar (47 acres, Conditional Use Permit);
- Elk Hills Solar by enXco (47 acres, Conditional Use Permit);
- Goose Lake Solar by enXco (94 acres, Conditional Use Permit);
- Smyrna Solar by enXco (125 acres, Conditional Use Permit);
- Cynergy Power (29 acres, Conditional Use Permit);
- RE Old River One and Two Solar Projects (105 acres, Conditional Use Permit);
- Valley Solar Projects by EnXco – an application for a Conditional Use Permit to serve four PV solar facilities on a total of 309 acres near Taft, Elk Hills, Dustin Acres and Arvin, California;
- Pioneer Green Solar (3 sites, 480 acres, Conditional Use Permit);
- SunGen Solar by LaPaloma (398 acres, Conditional Use Permit);
- FRV Orion Solar (265 acres, Conditional Use Permit and Williamson Act cancellation);
- Wasco-Chara (72 acres, Conditional Use Permit);
- Kern Solar Ranch Project (6,100 acres, zone change and Conditional Use Permit);
- Chaparral Solar (172 acres, Conditional Use Permit);
- Browning Road Solar (28 acres, Conditional Use Permit);
- Twisselman Solar (103 acres, Conditional Use Permit);
- Axio Power (Conditional Use Permit);
- Beacon PV Project;
- Pond-Poso Solar (35 acres, Conditional Use Permit); and
- Ignite Solar (40 acres, Conditional Use Permit)

In addition, staff reviewed the Kern County Planning Department's website and there are 14 projects with Notice of Preparations that staff consider reasonably foreseeable projects being developed in Kern County; however the occurrence of these projects on the Kern Valley floor is unknown (Kern County Planning and Community Development Department 2010):

- Caliente Sand and Gravel by Caliente Sand and Mineral;
- Desert Solar Project by EnXco – an application for two conditional use permits to operate a solar PV power generation plant proposed near California City, Kern County on a 1,270-acre site;
- Fremont Valley Preservation Project by AquaHelio Resources, LLC;
- FRV Orion Solar Project;
- High Desert Solar by Element Power;
- Kingbird Solar Project;
- Lehigh Alternative Fuels Project by Lehigh Southwest Cement Company;
- Monte Vista Solar Array by First Solar Inc. – an application for a zone change and Conditional Use Permit for construction of a PV solar facility on 1,040 acres near the community of Mojave, California;
- Nautilus Solar Energy Photovoltaic Project – an application for a zone change and Conditional Use Permit for a PV solar facility on approximately 150 acres near Rosamond and Mojave, California;
- Pioneer Green Energy Solar Project;
- Rising Tree Wind Farm Project;
- Rosamond Solar Array by First Solar, Inc – an application for a Specific Plan Amendment, Conditional Use Permit, and concurrent zone change for a PV solar facility on 1,177 acres near Rosamond, California;
- Solari Sand and Gravel Project by Granite Construction;
- Willow Spring Solar Array by First Solar, Inc – an application for a Specific Plan Amendment, Conditional Use Permit, and concurrent zone change for a PV solar facility on 1,400 acres near Rosamond, California.

Lastly, Kern County has the following list of project's with CEQA environmental documents in preparation that staff is considering active, currently proposed projects in the Kern County area; however the occurrence of these projects on the Kern Valley floor is unknown:

- Alta East Wind Project;
- Alta Infill II Wind Energy Project EIR;
- Alta-Oak Creek Mojave Project EIR;

- Antelope Valley Solar EIR proposed by Renewable Resource Group - an application for a Specific Plan Amendment, cancellation of a Williamson's Act contract, concurrent zone change, and Conditional Use Permit for a PV solar facility on a 5,400-acre site located near Rosamond, Kern County California;
- Avalon Wind Energy Project;
- Beech Avenue Industrial Park Project;
- Catalina Renewable Energy;
- Clean Harbors Hazardous Waste Disposal Facility;
- Clearvista Wind;
- Frazier Park Estates Recirculated;
- Greater Tehachapi Area Specific Plan;
- Kern River Valley Specific Plan;
- Liberty Energy Center Biofuels Gasification;
- Lower West Wind Energy;
- Mojave-Rosamond Recycling and Sanitary Landfill;
- Morgan Hills Wind Energy;
- North Sky River Wind Energy Project and Jawbone Wind Energy;
- Pacific Wind Energy;
- PdV Wind Energy;
- Reina Ranch;
- Ridgecrest Recycling and Sanitary Landfill;
- Rosamond Solar Project by SGS Antelope Valley – an application for a Specific Plan Amendment, Conditional Use Permit, and concurrent zone change for a PV solar facility on 960 acres Rosamond, California;
- Rosedale & Renfro Precise Development Plan;
- Soledad Mountain;
- Taft Sanitary Landfill; and
- Tejon Mountain Village

Implementation of all of the above listed projects, which is not intended to be a comprehensive list of proposed development, along with HECA would undoubtedly contribute to a significant cumulative effect to plants, wildlife, and other sensitive resources primarily in terms of habitat loss and fragmentation. The analysis of the contribution of HECA alone to a cumulative impact is complex. If the 25 proposed solar projects on the Kern Valley floor listed above were permitted and constructed, an estimated loss of approximately 15,230 acres of land would occur. The HECA project alone would result in the loss of approximately 773 acres of lands in an agricultural setting, amounting to approximately 5 percent of the total loss due to solar projects, which does not include the proposed wind and other non-energy projects proposed on this part of the Kern Valley floor. Several of the linear facilities are proposed along and near existing agricultural canals and irrigation ditches that the San Joaquin kit fox, in particular, is known to use for dispersal and movement; therefore, construction of these facilities could disrupt wildlife movement. Additionally, almost all of the PV solar facility plants in the above list involve the cancellation of a Williamson's Act contract indicating presently farmed agricultural fields would be lost to development, an incrementally significant loss of foraging habitat for Swainson's hawk. Staff believes implementation of the above projects would exacerbate threats to survival of upland species covered under the Recovery Plan. In order to determine if the project's contribution to the combined cumulative effect would be cumulatively considerable, additional data is needed regarding the project's effects of vehicle mortality to wildlife, habitat loss, and a comprehensive mitigation strategy. With the incorporation of Conditions of Certification **BIO-1** through **BIO-20** impacts to upland species would be reduced and minimized where possible; however, staff cannot determine if the project's contribution to cumulative impacts to upland species of the southern San Joaquin Valley would be cumulatively considereable without the submittal of this data.

DOE'S FINDINGS REGARDING DIRECT AND INDIRECT IMPACTS OF THE NO ACTION ALTERNATIVE

Under the No-Action Alternative, DOE would not provide financial assistance to the applicant for HECA. The applicant could still elect to construct and operate its project in the absence of financial assistance from DOE, but DOE believes this is unlikely. For the purposes of analysis in the PSA/DEIS, DOE assumes the project would not be constructed under the No-Action Alternative. Accordingly, the No-Action Alternative would have no impacts associated with this resource area.

COMPLIANCE WITH LORS

The project must comply with state and federal laws, ordinances, regulations, and standards (LORS) that address the protection of state and federally listed species and other sensitive species and habitats. The project's compliance with applicable LORS is summarized in **Biological Resources Table 10**. The Energy Commission has a one-stop permitting process for all thermal power plants rated 50 MW or more under the Warren-Alquist Act (Pub. Resources Code § 25500). Under the Warren-Alquist Act, the Energy Commission's license is "in-lieu of" other state, local, and regional permits (*ibid*.). Accordingly, staff has coordinated joint environmental review with CDFW and consulted with USFWS regarding compliance with federal LORS. The project's compliance with state and federal LORS is discussed in further detail following **Biological Resources Table 10.**

Biological Resources Table 10
Summary of HECA Project Compliance with LORS

Applicable LORS	Rationale for Compliance or Non-compliance
FEDERAL	
Endangered Species Act (Title 16, United States Code, section 1531 et seq., and Title 50, Code of Federal Regulations, part 17.1 et seq.)	The project has not demonstrated compliance with ESA at this time. The Department of Energy has re-initiated Section 7 ESA consultation and a revised Section 7 Biological Assessment has been submitted to the USFWS (**Biological Resources Appendix A**). Incorporation of staff's proposed Conditions of Certification **BIO-1** through **BIO-20** which require measures to avoid or mitigate impacts to federally listed species would aid in ensuring compliance with ESA; however, additional information is needed on the project's overall listed species mitigation strategy. Staff has inserted **BIO-20** as a placeholder for federally-listed species habitat compensation.
Migratory Bird Treaty Act (Title 16, United States Code, sections 703 through 711)	The project's compliance with MBTA is unknown at this time. Staff's proposed Conditions of Certification **BIO-9**, **BIO-10**, and **BIO-11** require the applicant to perform pre-construction surveys and identify nests for Swainson's hawk, burrowing owl and all nests of bird species protected by MBTA; however additional data is needed regarding the source of water supply and effects of groundwater pumping on raptor nest trees which may constitute take under MBTA.
Clean Water Act (Title 33, United States Code, sections 1251 through 1376, and Code of Federal Regulations, part 30, section 330.5(a)(26))	It is unclear whether the project complies with CWA at this time since the Corps has not issued a Jurisdictional Determination for the project. Staff's proposed Condition of Certification **BIO-19** would minimize the project impacts to potentially jurisidcitonal waters of the U.S.
STATE	
California Endangered Species Act of 1984 (Fish and Game Code, sections 2050 through 2098)	The project'scompliance with CESA is unknown at this time. Additional data and coordination with CDFW is needed on the project's potential impact to Swainson's hawk nest trees, a state-listed species, in terms of groundwater drawdown and nest tree decline, which may constitute take under CESA. Also, blunt-nosed leopard lizard is a state-listed species and since incidental take of this species cannot legally be granted nor can avoidance of take be guaranteed for the life of the project, HECA may not comply with CESA. Incorporation of staff's proposed Conditions of Certification **BIO-1** through **BIO-20** which require measures to avoid or mitigate impacts to state listed species would aid in ensuring compliance with CESA; however, additional information is needed on the project's overall listed species mitigation strategy. Staff has inserted **BIO-20** as a placeholder for state-listed species habitat compensation.

Applicable LORS	Rationale for Compliance or Non-compliance
Fully Protected Species (Fish and Game Code, sections 3511, 4700, 5050, and 5515)	It is unclear whether the project would complywith Fish and Game Code Section 5050 relating to Fully Protected Reptile and Amphibian Species (blunt-nosed leopard lizard) at this time. Staff concludes that even with the implementation of **BIO-1** through **BIO-20** including proposed take avoidance and minimization measures in **BIO-8**, incidental take of blunt-nosed leopard lizard would like occur over the life of the project; therefore, it is unclear whether the project would comply with FGC Section 5050.
Nest or Eggs (Fish and Game Code section 3503); Birds of Prey (Fish and Game Code section 3503.5); Migratory Birds (Fish and Game Code section 3513)	The project's compliance with Fish and Game Code Section 3503, 3503.5, and 3513 is unkonwn at this time. Additional data and coordination with CDFW is needed on the project's potential impact to raptor nest trees in terms of groundwater drawdown and nest tree decline which may constitute take under Fish and Game Codes 3503, 3503.5, and 3513. Staff's proposed Conditions of Certification **BIO-9**, **BIO-10**, and **BIO-11** require the applicant perform pre-construction surveys and identify nests for Swainson's hawk, burrowing owl and all nests of bird species protected by MBTA will minimize impacts.
Designated Ecological Reserves (Fish and Game Code section 1580 et seq.)	The project would not impact the Buttonwillow or Lokern Ecological Reserves; therefore, the project is compliant.
Streambed Alteration Agreement (Fish and Game Code sections 1600 et seq.)	It is unknown whether the project would comply with Fish and Game Code Section 1600 at this time since the extent of Section 1600 jurisdiction over the project has not been determined by CDFW. The applicant has submitted a Section 1600 Lake or Streambed Alteration Agreement application which staff has preliminarily reviewed. Staff has inserted **BIO-19** impact avoidance and minimization measures for potential state waters and **BIO-20** as a placeholder for mitigating project impacts to state waters.

FEDERAL LORS

ENDANGERED SPECIES ACT

Potential take of federally-listed species (i.e., federally endangered San Joaquin kit fox, federally endangered blunt-nosed leopard lizard, federally endangered giant kangaroo rat, federally endangered Tipton kangaroo rat, federally endangered Buena Vista Lake shrew) requires compliance with the federal Endangered Species Act (ESA; 16 USC §§ 1531 et seq.). "Take" of a federally listed wildlife species is prohibited without a permit, which may be obtained through consultation with USFWS under Section 10 of ESA by a private party or initiation of formal consultation under Section 7 of ESA by a federal agency. Since USFWS cannot issue incidental take coverage for federally-listed plants species, like Kern mallow, avoidance of special-status plant species is strongly encouraged.

HECA involves a federal nexus through the receipt of DOE federal funding; therefore, DOE is the federal agency initiating formal consultation with USFWS under Section 7 of ESA. A Section 7 Biological Assessment (BA) was submitted on March 6, 2013 for HECA including the OEHI component proposed on EHOF (**Biological Resources**

Appendix A). Following the conclusion of formal consultation, the USFWS would issue a Biological Opinion (BO) for the entire project, the conservation measures of which would be incorporated into the Energy Commission Decision through Condition of Certification **BIO-5** (Biological Resources Mitigation Implementation and Monitoring Plan). Compliance of the project with the Endangered Species Act cannot be determined at this point.

CLEAN WATER ACT

Potentially jurisdictional waters of the U.S. under Section 404 of the Clean Water Act occur within the project area including the Westside Canal/Outlet Canal, Kern River Flood Control Channel (KRFCC), California Aqueduct, the Kern River farther south of the project site, and several agricultural and irrigation ditches. The applicant has submitted a formal wetland delineation to the Corps and to date, the Corps has not issued a formal Jurisdictional Determination on the occurrence of Section 404 jurisdictional waters in the project area. The applicant identified a total of 92.51 acres of waters of the U.S. in the project area although the project awaits response from the Corps on the jurisidciton of these delineated features under Section 404. Therefore, compliance of the project with the Clean Water Act cannot be determined at this point.

STATE LORS

CALIFORNIA ENDANGERED SPECIES ACT

The California Endangered Species Act prohibits the "take" (defined as "to hunt, pursue, capture, or kill, or attempt to hunt, pursue, catch, capture, or kill") of state-listed species except as otherwise provided in state law. Staff is coordinating with the CDFW regarding the project's potential for take of state-listed species (i.e., state threatened Swainson's hawk, state threatened San Joaquin antelope ground squirrel, state threatened San Joaquin kit fox, state endangered Tipton kangaroo rat, state endangered and California Fully Protected blunt-nosed leopard lizard, and state endangered giant kangaroo rat) in order to incorporate any measures that would be required in an Incidental Take Permit under Section 2081 of the California Endangered Species Act into staff's conditions of certification, excluding blunt-nosed leopard lizard from the list above since incidental take of this species cannot be authorized. During May 2013, the applicant submitted an application for an Incidental Take Permit to CDFW and the Energy Commission (URS 2013d) although it is unknown whether the project complies with CESA at this time. Additional data and coordination with CDFW is needed on the project's potential impact to Swainson's hawk nest trees, a state-listed species, in terms of groundwater drawdown and nest tree decline, which may constitute take under CESA. Also, blunt-nosed leopard lizard is a state-listed species and since incidental take of this species cannot legally be granted nor can avoidance of take be guaranteed for the life of the project, the project may not comply with CESA.

CALIFORNIA FISH AND GAME CODE SECTION 1600

Similar to the state Incidental Take Permit, compliance with Fish and Game Code Section 1600 is achieved through the Energy Commission's in lieu authority. The applicant has submitted an application for a Lake or Streambed Alteration Agreement to staff and CDFW which staff has preliminarily reviewed. Staff believes ephemeral drainages occur along the proposed carbon dioxide pipeline route that may fall under Fish and Game Code 1600 jurisdiction. Until this information is submitted, compliance of the project with Section 1600 of the California Fish and Game Codes cannot be determined at this point.

CALIFORNIA FISH AND GAME CODE SECTION 5050

Staff concludes that even with the implementation of the identified take avoidance and minimization measures in Condition of Certification **BIO-8**, incidental take of BNLL would likely occur over the life of the project. Staff notes that any impacts to BNLL habitat loss even if mitigated as required under CEQA, the project may still violate the California Fish and Game Code Section 5050 and Section 86 which defines take due to the species' status as a California Fully Protected species since the avoidance of BNLL take cannot be guaranteed for the life of the project; therefore, it is unclear whether the project would comply with these LORS.

NOTEWORTHY PUBLIC BENEFITS

Construction and operation of the HECA Project would not result in any noteworthy public benefits with regard to biological resources.

CONCLUSIONS

Construction of the project would primarily impact agricultural lands and intermixed non-native grassland, allscale scrub habitats that provide habitat for a number of upland species covered under the U.S. Fish and Wildlife Service's *Recovery Plan for Upland Species of the San Joaquin Valley* (Recovery Plan, USFWS 1998). HECA would impact approximately 33 acres of allscale scrub habitat which would mostly occur along the carbon dioxide pipeline route. The proposed carbon dioxide pipeline route located on the lower flanks of the Elk Hills Oil Field and immediately north of the Elk Hills mitigation parcels, is the linear route that supports the most contiguous natural, non-farmland type of habitat in the project area and staff believes this linear route represents the highest quality natural habitat and poses the highest threat for construction impacts to upland species. In addition, five sites along the natural gas pipeline route also support areas of disturbed allscale scrub and some of these sites represent similar habitat values as the nearby Buttonwillow Ecological Reserve, located north of the project site. Approximately 740 acres of additional impacts would occur to various agricultural land types (alfalfa, orchards, row crops) and existing disturbed lands.

HECA is proposed for an area located in a San Joaquin kit fox Core Recovery Area known as natural lands of western Kern County, which include critical dispersal and connection points between the Elk Hills, Buena Vista Valley, and Lokern Natural Areas, and urban Bakersfield satellite populations of kit fox. The Recovery Plan states that the Carrizo Plain and western Kern County San Joaquin kit fox populations are important for kit fox recovery and preliminary population viability analyses indicate that the possibility of the extinction of this species dramatically increases if either the Carrizo

Plain or western Kern County populations are eliminated (USFWS 1998). Staff estimates the project's impacts to 773 acres of habitat represents a loss of denning and regional movement lands for San Joaquin kit fox. HECA would not result in the construction of any new roads; however, construction and operation would contribute considerable amounts of increased traffic on several local and collector roads that intersect with other irrigation canals that kit fox are known to use for movement. Staff believes increased vehicle traffic from the project, especially non-peak traffic during dawn, dusk and nighttime hours, could result in a considerable increase in direct vehicle-fox strike mortality and all wildlife that occurs on or near roadways. Staff has proposed Condition of Certification **BIO-7**, which requires that the applicant conduct focused den surveys prior to construction for San Joaquin kit fox and American badger, establish exclusion zones, and continue monitoring the activity of potential dens identified in active construction areas. Condition of Certification **BIO-7** also requires that the applicant follow the USFWS's *Standardized Recommendations for Protection of the San Joaquin Kit Fox Prior to or during Ground Disturbance* for avoiding impacts to this species (USFWS 2011). Staff's proposed Condition of Certification **BIO-12** requires that the applicant prepare an agency-approved Small Mammal Relocation Plan. In addition, staff has proposed Conditions of Certification **BIO-13** (giant kangaroo rat) and **BIO-14** (Tipton kangaroo rat and San Joaquin antelope squirrel), which require the applicant perform focused preconstruction surveys and mapping for giant kangaroo rat precincts and small mammal burrows, preconstruction trapping and relocation in order to minimize and avoid take of small burrowing mammals in active construction areas, and burrow excavation once burrows and precincts have been completely trapped and evaluated for small mammal presence.

Blunt-nosed leopard lizard is a California fully-protected species under California Fish and Game Code Section 5050 and therefore, incidental take of the species is not legally permitted as defined by Section 86 of the Fish and Game Code. This species is present at the Elk Hills Oil Field and has a high potential to occupy the proposed carbon dioxide pipeline route as well as disturbed allscale scrub areas along the natural gas pipeline. The construction of the project would impact approximately 192 acres of natural allscale scrub and disturbed lands which provide small mammal burrow habitat for blunt-nosed leopard lizard; this poses a threat to BNLL in the form of mortality from vehicles and equipment on roadways, entrapment in construction-related trenches or pipes, burial in burrows by equipment, avoidance of certain habitats, modification to breeding and/or foraging behaviors, reduced carrying capacity of natural scrub habitat and neighboring lands known to be occupied by BNLL. Staff has proposed Condition of Certification **BIO-8**, which requires that the applicant prepare a Blunt-nosed Leopard Lizard Impact Avoidance and Minimization Plan to further minimize the potential for take during construction and operation of the project; in particular, this plan would take into consideration the phasing of linear construction and how clearance surveys, exclusion fencing, and fence and burrow monitoring would also be phased in order to ensure blunt-nosed leopard lizards remain clear of active construction areas. Condition of Certification **BIO-8** also requires that various impact avoidance measures be incorporated including scheduling surface ground disturbing during the blunt-nosed leopard lizard's active season (approximately April 15 to October 15) to the greatest extent practicable, particularly in habitat areas where this species is mostly likely to be encountered, minor shifts in proposed pipeline alignments in order to avoid potentially occupied small mammal burrows, and presence of biological monitor(s) in active construction areas. Staff concludes that even with the implementation of staff's proposed take avoidance and minimization measures, incidental take of blunt-nosed leopard lizard would likely occur over the life of the project. Therefore, staff considers this impact significant and unavoidable under CEQA even with the incorporation of mitigation and the project may not comply with the California Endangered Species Act or California Fish and Game Code Section 5050 relating to Fully Protected Reptile and Amphibian Species since take avoidance cannot be guaranteed for the life of the project.

During protocol-level surveys performed for Swainson's hawk, 12 active raptor nests were found within the surveyarea, six of which were confirmed Swainson's hawk nests. All six Swainson's hawk nests appear to be within a 0.25 mile of either the project site or a proposed linear facility and therefore could be affected by construction noise or other construction disturbances during the nesting season. The majority of these nest trees occur along canal levees of the Kern River Flood Control Channel, West Side Canal and other smaller unnamed agricultural canals and ditches and are likely supplied to some extent by irrigation runoff that accumulates in irrigation canals as well as groundwater. In addition, valley sink scrub, a sensitive vegetation community identified by the California Natural Diversity Database, potentially occurs in these same areas in association with the Kern River Flood Control Channel. Staff believes that a more definitive analysis is needed on the water source of the nest trees that occur in the project area and pre- and post-project groundwater drawdown around the proposed well field. Staff also believes the loss of approximately 571 acres of agricultural lands including alfalfa, wheat, onion fields, and other low-growing crop types that provide forage value is a significant loss of foraging habitat for Swainson's hawk. More definitive analysis is needed on the baseline groundwater levels and water source of the nest trees and sensitive vegetation communities that occur in the project area. Staff's proposed Condition of Certification **BIO-9** (Swainson's Hawk Impact Avoidance Measures) requires that the applicant perform focused, preconstruction surveys within 0.50-mile of all project facilities and a minimum construction avoidance buffer of 0.50 mile must be implemented around any active Swainson's hawk nests following the recommended survey protocol for this species. Condition of Certification **BIO-9** also requires the applicant to prepare and implement a Swainson's Hawk Monitoring and Mitigation Plan which would account for a phased construction schedule and need to phase preconstruction surveys. With the incorporation of the above conditions of certification, the project's impacts to Swainson's hawk habitat would be reduced; however, until additional data is provided regarding the project's impacts and overall mitigation strategy, staff cannot determine if the project's impacts to Swainson's hawk habitat would be reduced to below a level of significance. If water drawdown from project groundwater pumping is consistent enough over the course of several years, staff believes the decrease in water supply to the tree's root system could result in gradual decline and eventually nest tree failure which may constitute take under the California Endangered Species Act, the Migratory Bird Treaty Act, and California Fish and Game Code 3503; therefore, it is unknown if HECA complies with these LORS at this time.

Staff has proposed several impact avoidance and minimization measures to reduce the potential for impacts to special-status plants and wildlife primarily during construction of the project. Specifically, staff has proposed Conditions of Certification **BIO-1** through **BIO-6** which would apply to all species that could be impacted by the project by requiring the applicant appoint a Designated Biologist and Biological Monitors for routine monitoring and reporting of the project during construction and implementation of a worker awareness training program. Conditions of Certification **BIO-7** through **BIO-17** are species-specific conditions, which in essence require the applicant perform focused, preconstruction surveys in suitable habitat areas, implement species- specific construction impact avoidance measures, and monitor for signs of disturbance during construction following wildlife agency protocols. These conditions also require the applicant to prepare species-specific mitigation and monitoring plans specifically for blunt-nosed leopard lizard, Swainson's hawk, burrowing owl, and listed small mammals (giant kangaroo rat, Tipton, San Joaquin antelope squirrel) outlining construction avoidance procedures and to take into account the phasing of the construction schedule along linear routes when implementing clearance surveys.

Energy Commssion staff, the California Department of Fish and Wildlife (CDFW), and U.S. Fish and Wildlife Service (USFWS) have determined that permanent protection and perpetual management of compensatory habitat is necessary and required in accordance with CEQA and biological laws, ordinances, regulations, and standards (LORS). This determination is based on factors including an assessment of the importance of the habitat in the project area and the extent to which project activities would impact the habitat. There remains much uncertainty regarding the applicant's overall compensatory mitigation proposal for the project. The applicant submitted a Section 7 Biological Assessment for HECA including the OEHI component of HECA on March 1, 2013 (Biological Resources Appendix A, URS 2013b). The applicant has proposed to mitigate for permanent and temporary habitat impacts to federally and state listed species at a 0.1:1 and 2.1:1 ratio, respectively, which staff believes would not suffice as adequate habitat compensation for project impacts to special-status species (HECA 2012b, URS 2013b). The applicant has also proposed to purchase habitat credits from the Kern Water Bank as mitigation for the project, which the wildlife agencies have indicated is not a feasible option for mitigating HECA's impacts to special-status wildlife species. During May 2013, the applicant submitted a Section 2081 Incidental Take Permit application which would contain a mitigation strategy for project impacts to state-listed wildlife species that staff has preliminarily reviewed. Staff has inserted Condition of Certification **BIO-20** (Compensatory Habitat Mitigation for Upland Species) as a placeholder. Staff will continue to work publicly with the applicant, CDFW, and USFWS in order to develop an appropriate mitigation strategy for HECA that is consistent with the goals and objectives of the *Recovery Plan for Upland Species of the San Joaquin Valley*. Additional conditions of certification, and modifications to currently proposed conditions of certification including Condition of Certification **BIO-20**, are likely to be necessary based on further consultation with the wildlife agencies and information provided by the applicant. With the implementation of staff's proposed Conditions of Certification **BIO-1** through **BIO-20**, impacts to special-status species would be reduced. However, without an adequate mitigation proposal, staff cannot make a determination whether the project would comply with laws, ordinances, regulations, or standards (LORS) or that project impacts to sensitive biological resources would be reduced to less than significant levels in accordance with CEQA.

OUTSTANDING INFORMATION REQUIRED FOR COMPLETION OF THE FSA/FEIS

The following is a list of information related to biological resources that the applicant must provide to staffin order to finalize preparation of the FSA/FEIS:

- Comprehensive mitigation strategy for project impacts to San Joaquin kit fox, giant kangaroo rat, Tipton kangaroo rat, San Joaquin antelope squirrel, blunt-nosed leopard lizard, Swainson's hawk, burrowing owl and HECA's incremental contribution to cumulative effects to these species that are covered in the *Recovery Plan of Upland Species of the San Joaquin Valley*. Specifically, identify which species and acreage the applicant is proposing to mitigate through purchase of mitigation credits from the Kern Water Bank and which species and acreages would be mitigated through offsite land acquisition. For offsite land acquisition, please identify the species-specific habitat critieria for offsite mitigation lands and cost estimates for determining security (eg. cost estimates for land acquisition, start-up actitivites and initial habitat improvements, funding during the three-year interim management period, and long-term management). Please also provide any preliminary discussions with land management entities for land acquisition and long-term habitat management for project impacts to listed species;
- Additional focused protocol-level botanical surveys (CDFG 2009) along all linear routes and additional baseline botanical data, primarily the proposed carbon dioxide pipeline route;
- Extent of CDFW Section 1600 jurisdiction and impacts to state waters (ephemeral drainages) in the project area, including all linear routes and ephemeral drainages that may occur along the proposed carbon dioxide pipeline route;
- Extent of U.S. Army Corps of Engineers Section 404 jurisdiction in the project area and impacts to Waters of the U.S.;
- Habitat mitigation strategy for habitat loss impacts from OEHI component of HECA at the Elk Hills Oik Field. Please identify whether species impacts including habitat loss for the OEHI component would be included under the Section 10 Habitat Conservation Plan currently under preparation or if habitat loss for the OEHI component of HECA would be mitigated under separate consultations with CDFW and USFWS;
- Western spadefoot toad habitat assessment along project linear routes including upland refugia and aquatic habitats preferably during the wet season (defined as October 15 to April 15 of any given year) and following sufficient winter or spring rains in order to identify potential depressional areas and upland refugia that may provide habitat for western spadefoot toad. All potential ponding areas should be identified and mapped with a GPS unit including the single pond where this species was identified previously. Information to be collected at each GPS'ed potential breeding area includes, but is not limited to: the specific numbering system of each potential breeding area, presence of tadpoles and species (if any), habitat community, microhabitat features, observed plant species, observed

wildlife species including invertebrates, water temperature, approximate depth and surface area, and level of disturbance;

- Vehicle-fox strike and incidental take analysis considering the project's contribution to existing traffic volumes and intersections of the proposed construction and operation routes with other linear right-of-ways that occur within and outside of San Joaquin kit fox core recovery areas. The applicant should calculate vehicle mortality rates to kit fox and other mammals over the life of the project; and
- Water supply analysis and the effects of groundwater pumping to the sensitive vegetation communities and raptor nest trees which occur in the project area. The applicant must provide an analysis of the baseline groundwater levels and water source of raptor nest trees and alkali sink scrub habitat along HECA's linear routes, primarily the natural gas pipeline, processed water pipeline, and well field.

PROPOSED CONDITIONS OF CERTIFICATION

For the purposes of staff's proposed conditions of certification, staff defines project disturbance areas encompassing all areas to be temporarily and permanently disturbed by the project, including the plant site, linear facilities, and areas disturbed by temporary access roads, fence installation, construction work lay-down and staging areas, parking, storage, or any other area resulting in disturbance to soil or vegetation. Since the Energy Commission's license is in-lieu of all state permits normally required, incidental take per the California Endangered Species Act (CESA) and California Fish and Game Codes could be granted for the following covered species in accordance with the conditions of certification in the Energy Commission's license: San Joaquin kit fox, giant kangaroo rat, San Joaquin antelope squirrel, Tipton's kangaroo rat, and Swainson's hawk. Blunt-nosed leopard lizard is a California Fully Protected species and incidental take, including capture, is prohibited under California Fish and Game Code Section 5050. Therefore this species is not a covered species and incidental take of this species will not be authorized or granted through the Energy Commission's license. No state listed plants are covered species nor could incidental take be authorized.

Staff has inserted Condition of Certification **BIO-20** (Compensatory Habitat Mitigation) as a placeholder, which would require the applicant to permanently protect and perpetually manage compensatory habitat. However, the estimate of the acreage required to provide for adequate compensation is unknown at this time and will be finalized upon preparation of the FSA/FEIS upon submittal of the data requested and further public consultation between the applicant, staff, CDFW, and USFWS. The need for compensatory mitigation is based on factors including an assessment of the importance of the habitat in the project area and the extent to which the project would impact the habitat.

DESIGNATED BIOLOGIST SELECTION AND DUTIES

BIO-1 The project owner shall assign at least one Designated Biologist to the project. The project owner shall submit the resume of the proposed

Designated Biologist, with at least three references and contact information, to the Energy Commission compliance project manager (CPM) for approval, in consultation with California Department of Fish and Wildlife (CDFW) and U.S. Fish and Wildlife (USFWS).

The Designated Biologist shall meet the following minimum qualifications:

1. Bachelor's degree in biological sciences, zoology, botany, ecology, or a closely related field;
2. Three years of experience in field biology or current certification of a nationally recognized biological society, such as The Ecological Society of America or The Wildlife Society;
3. Have at least one year of field experience with biological resources and demonstrate an understanding of field survey protocols for sensitive plant and wildlife species found in or near the project area; and
4. Meet all surveyor requirements specified in agency qualifications for performing protocol-level surveys as a Level II blunt-nosed leopard lizard researcher (CDFG 2004) and San Joaquin kit fox (USFWS 1999) qualified surveyor.

The project owner shall ensure that the Designated Biologist performs the following duties during any project mobilization activities, construction-related ground disturbance, site vegetation clearing, grading, boring or trenching activities. The Designated Biologist may be assisted by an approved Biological Monitor(s) but the Designated Biologist remains the main point of contact for the project owner and CPM. The Designated Biologist duties include the following, but are not limited to:

1. Advise the project owner's construction and operation managers on the implementation of the biological resources conditions of certification;
2. Consult on the preparation of the Biological Resources Mitigation Implementation and Monitoring Plan (BRMIMP) to be submitted by the project owner;
3. Be available to supervise, conduct, and coordinate mitigation, monitoring, and other biological resources compliance efforts, particularly in areas requiring avoidance or containing sensitive biological resources, such as special-status species or their habitat;
4. Ensure that the onsite blunt-nosed leopard lizard preconstruction surveying and monitoring crews at all times consist of no more than three Level I surveyors for every single Level II surveyor;
5. Clearly mark sensitive biological resource areas and inspect these areas at appropriate intervals for compliance with regulatory terms and conditions;
6. Inspect active construction areas including all open trenches where animals may have become trapped prior to construction commencing each day. At the end of the day, inspect for the installation of structures

that prevent entrapment or allow escape during periods of construction inactivity. Periodically inspect areas with high vehicle activity (e.g., parking lots) for animals in harm's way and relocated wildlife where appropriate;

7. Notify the project owner and the CPM of any non-compliance with any biological resources condition of certification;
8. Respond directly to inquiries of the CPM and Energy Commission Biological Resources staff regarding biological resource issues;
9. Maintain written records of the tasks specified above and those included in the BRMIMP. Summaries of these records shall be submitted in Monthly Compliance Reports and the Annual Compliance Report;
10. Train the Biological Monitors as appropriate, and ensure their familiarity with the BRMIMP, Worker Environmental Awareness Program (WEAP) training, and permits;
11. Maintain the ability to be in regular, direct communication with representatives of CDFW and USFWS as well as the CPM, including notifying these agencies of dead or injured listed species within 24 hours; and
12. Be onsite and available to perform or manage Biological Monitor survey crews during all pre-construction surveying and monitoring duties related to San Joaquin kit fox, giant kangaroo rat, San Joaquin antelope squirrel, Tipton's kangaroo rat, Swainson's hawk (collectively, Covered Species) in which incidental take in accordance with the California Endangered Species Act (CESA) and California Fish and Games Codes is authorized. Other non-covered species must be included in pre-construction surveys and monitored in accordance with applicable agency protocols, including blunt-nosed leopard lizard, burrowing owl, and special-status plants.

<u>Verification:</u> The project owner shall submit a resume including the specified information at least 60 days prior to the start of any project-related ground disturbance activities for review and approval to the CPM with copies to USFWS and CDFW. No ground-disturbing activities shall commence at the project site or along liner facilities until an approved Designated Biologist is available to be onsite. At least one approved, alternate Designated Biologist shall be identified and available to monitor if the primary Designated Biologist is unavailable.

If a Designated Biologist needs to be replaced, the specified information of the proposed replacement shall be submitted to the CPM with copies to USFWS and CDFW at least 10 working days prior to the termination or release of the preceding Designated Biologist. In an emergency, the project owner shall immediately notify the CPM to discuss the qualifications and approval of a short-term replacement while a permanent Designated Biologist is proposed to the CPM for consideration.

The Designated Biologist shall submit in the Monthly Compliance Report to the CPM copies of all written reports and summaries that document biological resources compliance activities. If actions may affect biological resources during operation a

Designated Biologist shall be available for monitoring and reporting. During project operation, the Designated Biologist shall submit record summaries in the Annual Compliance Report unless his/her duties cease, as approved by the CPM.

If a listed species is killed by project-related activities during construction, or if a listed species is otherwise found dead, the Designated Biologist shall immediately notify the CPM, USFWS Sacramento Field Office, and CDFW Central Region Office and provide information on the location, species and number of animals injured or killed. Following the initial notification, the project owner shall send the CPM, CDFW, and USFWS a written report within three (3) calendar days of the finding. The report shall include the date, time, location of the finding or incident, location of the carcass, and if possible provide a photograph, cause of death, and any other pertinent information.

BIOLOGICAL MONITOR QUALIFICATIONS AND DUTIES

BIO-2 The project owner's approved Designated Biologist shall submit the resume, at least three references, and contact information of the proposed Biological Monitors to the CPM for approval, based on consultation with CDFW and USFWS. The resume shall demonstrate to the satisfaction of the CPM the appropriate education and experience to accomplish the assigned biological resource tasks. The Biological Monitors shall assist the Designated Biologist in conducting surveys and in monitoring of mobilization, ground disturbance, grading, construction, operation, and closure activities; however, the Designated Biologist shall remain the contact for the project owner and the CPM.

Biological Monitor(s) training by the Designated Biologist shall include familiarity with these conditions of certification, the Biological Resources Mitigation Implementation and Monitoring Plan (BRMIMP), Worker Environmental Awareness Program (WEAP), and all permits.

Biological Monitors shall meet the following minimum qualifications:

1. Demonstrated field experience in the identification and life history of the San Joaquin kit fox. In addition, biologist(s) must be able to identify coyote, red fox, gray fox, and kit fox tracks and scat, and to have seen a kit fox in the wild, at a zoo, or as a museum mount;
2. Demonstrated field experience identifying burrowing owl burrows and other sign;
3. Demonstrated field experience in identifying San Joaquin antelope squirrel, giant kangaroo rat, Buena Vista Lake shrew, and Tipton kangaroo rat and sign;
4. Demonstrated field experience in identifying special-status plant species known to occur in the project area; and

4\. All approved Biological Monitors must at least meet the requirements to be a CDFW-approved Level I blunt-nosed leopard lizard (BNLL) surveyor (i.e. demonstrated the ability to distinguish BNLL from other common lizard species that may inhabit the area).

Verification: The project owner shall submit resumes including the specified information for review and approval by the CPM with copies to USFWS and CDFW at least 60 days prior to the start of any project-related site ground disturbing aactivities. The Designated Biologist shall submit a written statement to the CPM confirming that individual Biological Monitor(s) has been trained including the date when training was completed. If additional Biological Monitors are needed during construction the specified information shall be submitted to the CPM for approval at least 10 days prior to their first day of monitoring activities.

DESIGNATED BIOLOGIST AND BIOLOGICAL MONITOR AUTHORITY

BIO-3 The project owner's construction and operation manager(s) shall act on the advice of the Designated Biologist and Biological Monitors to ensure conformance with the biological resources conditions of certification.

The approved Designated Biologist and Biological Monitors shall have the authority to immediately stop any activity that is not in compliance with these conditions and/or order any reasonable measure to avoid take of an individual of a listed species. If required by the Designated Biologist and Biological Monitors the project owner's construction/operation manager shall halt all site mobilization, ground disturbance, grading, construction, and operation activities in areas specified by the Designated Biologist or Biological Monitor. The Designated Biologist or Biological Monitor shall:

1. Require a halt to all activities in any area when determined that there would be an unauthorized adverse impact to biological resources if the activities continued;
2. Inform the project owner and the construction/operation manager when to resume activities; and
3. Notify the CPM if there is a halt of any activities and advise the CPM of any corrective actions that have been taken or will be instituted as a result of the work stoppage.

If the Designated Biologist is unavailable for direct consultation, the Biological Monitor shall act on behalf of the Designated Biologist.

Verification: The project owner shall ensure that the Designated Biologist or Biological Monitor notifies via phone or email the CPM immediately (i.e. no later than the morning following the incident, or Monday morning in the case of a weekend) of any non-compliance or a halt of any site mobilization, ground disturbance, grading, construction, and operation activities. The project owner shall notify via phone or email the CPM of the circumstances and actions being taken to resolve the problem.

Whenever corrective action is taken by the project owner, a determination of success or failure will be made by the CPM after receipt of notice that corrective action is completed, or the project owner will be notified by the CPM that coordination with other agencies will require additional time before a determination can be made.

WORKER ENVIRONMENTAL AWARENESS PROGRAM

BIO-4 The project owner shall develop and implement a Worker Environmental Awareness Program (WEAP) in which each of its employees, as well as employees of contractors and subcontractors who work on the project site and all related linear facilities during site mobilization, ground disturbance, grading, construction, operation, and closure are informed about sensitive biological resources associated with the project prior to their working on-site.

The WEAP shall:

1. Be developed by or in consultation with the Designated Biologist, based on input from the CPM, CDFW, and USFWS and consist of an onsite or training center presentation in which supporting written material and electronic media is made available to all participants, including photographs of protected species. Interpretation shall be provided for non-English speaking workers and the same instructions shall be provided for any new workers prior to their working on-site;

2. Discuss the locations and types of sensitive biological resources on the project site and adjacent areas including Environmentally Sensitive Areas and their designation on construction drawings and present the reasons for protecting these resources and protective measures that are being implemented;

3. Discuss the biology and general behavior of special-status species, information about the distribution and habitat needs of special-status species, sensitivity of these species to human activities, impact avoidance and minimization measures to follow during construction, and legal protection and recovery efforts. Specifically, the WEAP shall include the requirement to inspect all areas underneath parked vehicles for blunt-nosed leopard lizard (BNLL) prior to vehicle operation during the active season for BNLL (April 15 to October 15) and reporting measures to implement if a BNLL is found in a construction area.
4. Place special emphasis on covered species as well as burrowing owl, blunt-nosed leopard lizard, and special-status plants including information on physical characteristics, distribution, behavior, ecology, sensitivity to human activities, legal protection, penalties for violations, reporting requirements, and protection measures. Specifically, the WEAP shall discuss that any contractor or employee who is responsible for inadvertently killing or injuring a kit fox shall immediately report the incident to the Designated Biologist and subsequent agency notification and reporting requirements;

5. Provide pictures of covered species as well as blunt-nosed leopard lizard, American badger, burrowing owl, Buena Vista Lake shrew, and rare plants (Hoover’s eriastrum, gypsum-loving larkspur, Lost Hills crownscale, oil nest straw, San Joaquin bluecurls, cottony buckwheat, Tejon poppy, Kern mallow) and provide information on sensitivity to human activities, legal

protection, reporting requirements, and how to identify construction avoidance zones (including Environmentally Sensitive Areas) for these species as marked by flagging, staking, or other means;

6. Include a discussion of fire prevention measures to be implemented by workers during project activities and request workers to: a) use designated smoking areas and dispose of cigarettes and cigars appropriately and not leave them on the ground or buried, b) keep vehicles on graveled or well-maintained roads at all times, unless performing prescribed construction activities, to prevent vehicle exhaust systems from coming in contact with roadside weeds, c) use and maintain approved spark arresters on all power equipment, and d) keep a fire extinguisher on hand at all times;

7. Present the meaning of various temporary and permanent habitat protection measures as necessary;

8. Discuss penalties for violation of applicable federal and state laws, ordinances, regulations, and standards (LORS); and

9. Identify whom to contact if there are further comments and questions about the material discussed in the program.

The WEAP shall include a training acknowledgment form to be signed by each worker indicating that they received training and shall abide by the guidelines. This file shall indicate the name and contact information for each worker that has attended the WEAP. This list must be available to the CPM, USFWS, and CDFW upon request. Upon completion of the program, the project owner shall provide all workers who have completed the WEAP a hardhat sticker that must be displayed on their hardhat.

The specific program can be administered by a competent individual(s) acceptable to the Designated Biologist and copies of the WEAP shall be maintained at the work site. The WEAP may also contain wallet-sized cards or a fact sheet handout containing this information for workers to carry on-site. Throughout the life of the project, the WEAP shall be repeated annually for permanent employees, and shall be routinely administered within one week of arrival to any new construction personnel, foremen, contractors, subcontractors, and other personnel potentially working within the project area. Upon completion of the orientation, employees shall sign a form stating that they attended the program and understand all protection measures. These forms shall be maintained by the project owner and shall be made available to the CPM, USFWS, and CDFW upon request.

<u>Verification:</u> At least 60 days prior to construction-related ground disturbance, the project owner shall provide the draft WEAP and all supporting written materials and electronic media prepared or reviewed by the Designated Biologist to the CPM for review and approval with a copy to CDFW and USFWS. At least 10 days prior to site and related facilities mobilization, the project owner shall submit two copies of the final approved WEAP and video to the CPM with copies to the CDFW and USFWS.

In the Monthly Compliance Report, the project owner shall provide the number of persons who have completed the training in the prior month and a running total of all persons who have completed the training to date. Training acknowledgement forms signed during construction shall be kept on file by the project owner for a period of at least six months after the start of commercial operation. During project operation, signed statements for operational personnel shall be kept on file for six months following the termination of an individual's employment.

BIOLOGICAL RESOURCES MITIGATION IMPLEMENTATION AND MONITORING PLAN

BIO-5 The project owner shall develop and implement a Biological Resources Mitigation Implementation and Monitoring Plan (BRMIMP) for HECA. The BRMIMP shall incorporate all impact avoidance and minimization measures outlined in any applicable species mitigation plans subsequently prepared in accordance with these biological conditions of certification.

The BRMIMP shall be prepared in consultation with the Designated Biologist and shall include the following:

1. All biological resources mitigation, monitoring, and compliance measures specified in the conditions of certification;
2. All biological resource mitigation, monitoring and compliance measures required in federal agency terms and conditions, including the USFWS Biological Opinion for the project;
3. All sensitive biological resources to be impacted, avoided, or mitigated by project construction, operation, and closure;
4. A detailed description of measures that shall be taken to avoid or mitigate temporary disturbances from construction activities;
5. All locations on a map, at an approved scale, of sensitive biological resource areas subject to disturbance and areas requiring temporary protection and avoidance during construction;
6. GIS analysis utilizing aerial photographs, at an approved scale, of all areas to be disturbed during project construction activities; include one set prior to any site or related facilities mobilization disturbance and one set subsequent to completion of project construction, each set showing the project site plan boundaries and facilities. Provide planned timing of aerial photography and a description of why times were chosen. Provide a final accounting of the before/after acreages and a determination of whether additional habitat compensation is necessary in the Construction Termination Report;
7. Duration for each type of monitoring and a description of monitoring methodologies and frequency;
8. All performance standards to be used to help decide if/when proposed mitigation is or is not successful;

9. A discussion of biological resources-related facility closure measures including a description of funding mechanism(s); and
10. A process for proposing plan modifications to the CPM (in consultation with appropriate agencies) for review and approval.

Verification: The project owner shall provide a draft of the BRMIMP at least 60 days prior to start of any project mobilization or ground disturbance associated with the power plant site or linear facilities. The CPM, in consultation with other appropriate agencies, will review and approve the draft BRMIMP. If the Biological Opinion has not yet been received when the BRMIMP is first submitted, the Biological Opinion shall be submitted to the CPM within five (5) days of its receipt, and the BRMIMP shall be revised or supplemented to reflect the permit condition within 10 days of its receipt by the project owner. Thirty days prior to any ground disturbing project activities, the final BRMIMP shall be submitted to the CPM with copies to USFWS and CDFW. No ground disturbance may occur prior to approval of the final BRMIMP by the CPM.

The project owner shall notify the CPM no less than five working days before implementing any modifications to the approved BRMIMP to obtain CPM approval. Any changes to the approved BRMIMP must also be approved by the CPM in consultation with CDFW and USFWS to ensure that no conflicts occur with other permit requirements.

Implementation of BRMIMP measures will be reported in the Monthly Compliance Reports by the Designated Biologist and written reports documenting monthly biological compliance measures will be included (i.e., survey results, construction activities that were monitored, species observed, etc). Within thirty (30) days after completion of project construction, the project owner shall provide to the CPM, for review and approval, a written construction termination report identifying which items of the BRMIMP have been completed, a summary of all modifications to mitigation measures made during project site mobilization, ground disturbance, grading, and construction phases, and which mitigation and monitoring items are still outstanding.

IMPACT AVOIDANCE AND MINIMIZATION MEASURES

BIO-6 The project owner shall undertake the following measures to manage the construction site and related facilities in a manner to avoid or minimize impacts to biological resources:

1. Limit Disturbance Area. The boundaries of all areas to be disturbed (including staging areas, access roads, and sites for temporary placement of spoils) shall be delineated with stakes and flagging prior to construction activities in consultation with the Designated Biologist. Spoils shall be stockpiled in disturbed areas lacking native vegetation and which do not provide habitat for special-status species. Parking areas, staging and disposal site locations shall similarly be located in areas without native vegetation or special-status species habitat. All disturbances, vehicles, and equipment shall be confined to the flagged areas.

2. Minimize Road Impacts. New and existing roads that are planned for construction, widening, or other improvements shall not extend beyond the flagged impact area as described above. All vehicles passing or turning around will do so within the planned impact area or in previously disturbed areas. Where new access is required outside of existing roads or the construction zone, the route will be clearly marked (i.e., flagged and/or staked) prior to the onset of construction.

3. Minimize Traffic Impacts. Vehicular traffic during project construction and operation shall be confined to existing routes of travel to and from the project site, and cross country vehicle and equipment use outside designated work areas shall be prohibited. The speed limit shall not exceed 20 miles per hour on paved roads within the project area (10-mph on dirt roads), on non-public maintenance roads along linear routes (pipelines, transmission line, etc).

4. Monitor During Construction. Following all species-specific pre-construction clearance surveys following the applicable agency-approved survey protocol, the Designated Biologist or Biological Monitor shall be present at the construction site during all project construction activities and in work areas (including the project site and linear facilities) that have potential to disturb soil, vegetation, and wildlife. The Designated Biologist or Biological Monitor shall follow the survey and monitoring protocol that exists for the individual listed species or if a formal survey protocol does not exist, a comparable agency-approved survey and monitoring protocol.

5. Minimize Impacts of Transmission Lines/Pipeline Alignments, Roads, and Staging Areas. Transmission lines, access roads, pulling sites, storage and parking areas, and construction staging areas (at power plant site and rail yard) shall be designed, installed, and maintained with the goal of minimizing impacts to native plant communities and sensitive biological resources. Transmission lines and all electrical components shall be designed, installed, and maintained in accordance with the Avian Power Line Interaction Committee's (APLIC's) *Suggested Practices for Avian Protection on Power Lines* (APLIC 2006) and *Mitigating Bird Collisions with Power Lines* (APLIC 2004) to reduce the likelihood of large bird electrocutions and collisions.

6. Vegetation Clearing. All vegetation clearing shall be performed outside of the bird nesting season (September 1 through January 31), to the maximum extent practicable, in order to clear vegetation prior to the active bird nesting season.

7. Avoid Use of Toxic Substances. Road surfacing and sealants as well as soil bonding and weighting agents used on unpaved surfaces shall be non-toxic to wildlife and plants. Pre-emergents and other herbicides with documented residual toxicity shall not be used. Herbicides shall be applied in conformance with federal, state, and local laws and according to the guidelines for wildlife-safe use of herbicides. Use of rodenticides

and herbicides in project areas should be restricted as outlined in further detail in **BIO-7**.

8. Minimize Lighting Impacts. Facility lighting shall be designed, installed, and maintained to prevent side casting of light towards wildlife habitat. Lighting shall be shielded, directional, and at the lowest intensity required for safety. Lighting shall be directed away from biologically sensitive areas.

9. Minimize Noise Impacts. A continuous low-pressure technique shall be used for steam blows, to the extent possible, in order to reduce noise levels in sensitive habitat proximate to the power plant site. To the extent feasible, loud construction activities (e.g. unsilenced high pressure steam blowing and pile driving associated with all project facilities or other noise greater than 60 dBA) shall be avoided during the peak elk calving and nesting bird season (February 15th to June15th when construction noise levels would be greater than 60 dBA (excluding noise from passing vehicles) in nesting bird habitat and within immediate proximity of the Tule Elk State Reserve including construction of the transmission line.

10. Avoid Wildlife Pitfalls and Prevent Inadvertent Entrapment of Wildlife. To prevent inadvertent entrapment of kit foxes or other animals, the Designated Biologist or Biological Monitor shall monitor for wildlife pitfalls. At the end of each work day, the Designated Biologist or Biological Monitor(s) shall ensure that all excavated, steep-walled holes or trenches more than two feet deep shall be covered by plywood or similar materials. If trenches cannot be closed, one or more escape ramps shall be installed of either earthen fill or wooden planks at a 3:1 slope ratio at the ends or installed every 200 feet along the trench, whichever distance is shorter. Before such holes or trenches are filled, they should be thoroughly inspected for trapped animals. In addition, all construction pipes, culverts, or similar structures with a diameter of 4 inches or greater that are stored at a construction site for one or more overnight periods shall be thoroughly inspected for kit fox before the pipe is subsequently buried, capped, or moved. If a kit fox is discovered inside a pipe, that section of pipe shall not be moved. However, if necessary and approved by the CPM in consultation with USFWS and CDFW, the pipe may be moved once to remove it from the path of construction activity, until the kit fox has escaped and under the direct supervision of the Designated Biologist or Biological Monitor.

11. Minimize Standing Water. Water applied to dirt roads and construction areas (trenches or spoil piles) for dust abatement shall use the minimal amount needed to meet safety and air quality standards. A Biological Monitor shall patrol these areas to ensure water does not puddle, flood small mammal burrows, and attract wildlife to the site and shall take appropriate action to reduce water application where necessary.

12. Minimize Spills of Hazardous Materials. All vehicles and equipment shall be maintained in proper working condition to minimize the potential for fugitive emissions of motor oil, antifreeze, hydraulic fluid, grease, or other

hazardous materials. The Designated Biologist shall be informed of any hazardous spills immediately. Hazardous spills shall be immediately cleaned up and the contaminated soil properly disposed of at a licensed facility. Servicing of construction equipment shall take place only at a designated area. Service/maintenance vehicles shall carry a bucket and pads to contain leaks or spills.

13. Dispose of Road-killed Animals. Road-killed animals or other carcasses detected on project maintenance roads along linear routes and within one mile of the project site shall be picked up immediately and delivered to the Biological Monitor or Designated Biologist. For listed species road kill, the Designated Biologist or Biological Monitor shall contact USFWS and CDFW within 24 hours of receipt of the carcass for guidance on disposal or storage and need for necropsy of the carcass. The Biological Monitor or Designated Biologist shall report the special-status species record as described in these biological conditions of certification.

14. Worker Guidelines. During construction, all trash and food-related waste shall be placed in self-closing containers and removed daily from the site. Workers shall not feed wildlife or bring pets to the project site. Except for law enforcement personnel, no workers or visitors to the site shall bring firearms or weapons.

15. Avoid Spread of Noxious Weeds. The project owner shall implement the following Best Management Practices during construction and operation to prevent the spread and propagation of noxious weeds into new habitats as a result of the project:

    a. Limit the size of any vegetation and/or ground disturbance to the absolute minimum and limit ingress and egress to defined routes;

    b. Prevent spread of non-native plants via vehicular sources by implementing Trackclean™ or other methods of vehicle cleaning for vehicles coming and going from construction sites;

    c. Construction equipment shall be cleaned prior to transport to the construction site. Prior to equipment entering the work area, the contractor will notify the Designated Biologist so that a Biological Monitor or environmental inspector can inspect the equipment to ensure they are free of any dirt or mud that could contain weed seeds, roots, or rhizomes. The tracks, feet, tires, and undercarriage will be carefully inspected, and special attention will be paid to axles, frame, cross members, motor mounts, underneath steps, running boards, and front bumper/brush guard assemblies. All equipment will be washed off-site in truck wash facilities located in Bakersfield or truck stop facilities off of I-5 or other local highways. An on-site cleaning station will only be set up to clean equipment before they enter the work area if absolutely necessary. The on-site station would be large, well-graveled, and access to additional traffic restricted. Cleaning stations would use either high pressure water or air to remove dirt and mud from equipment and vehicles and would be located away from any sensitive biological resources;

d. Implement Pesticide Use Best Management Practices. During construction and operation the project owner shall conduct pesticide management in accordance with standard Best Management Practices (BMPs). The BMPs shall include non-point source pollution control measures. The project owner shall use a licensed herbicide applicator and obtain recommendations for herbicide use from a licensed Pest Control Advisor. Use of rodenticides and herbicides in project areas shall be restricted and any herbicide use must be reviewed and authorized foruse by the CPM in consultation with the USFWS and CDFW prior to application. All uses of such compounds shall observe label and other restrictions mandated by the U.S. Environmental Protection Agency, California Department of Food and Agriculture, and other state and federal legislation. If rodent control must be conducted, only zinc phosphide shall be used and application is only allowed in the power plant buildings. Use of rodenticides and herbicides in the project area will not use chemicals and pesticides known to cause harm to non-target plants and wildlife;

e. Use only certified noxious weed-free straw, hay bales, straw waddles, and seed for erosion control and sediment barrier installations;

f. Avoid using invasive non-native species in landscaping plans and erosion control;

g. Cleared vegetation and salvaged topsoil will be stockpiled adjacent to the area from which they are stripped to eliminate the transport of soil borne noxious weed seeds, roots, or rhizomes;

h. Employing manual, mechanical, and chemical control methods as appropriate to target invasive plant species; and

i. Include information on the prevention of spreading weeds in the WEAP.

16. <u>Implement Erosion Control Measures</u>. Standard erosion control measures shall be implemented for all phases of construction and operation where sediment run-off from exposed slopes threatens to enter any identified waters of the U.S. or waters of the state. Sediment and other flow-restricting materials shall be moved to a location where they shall not be washed back into the stream. All disturbed soils and roads within the project site shall be stabilized to reduce erosion potential, both during and following construction. Areas of disturbed soils (access and staging areas) with slopes toward a drainage shall be stabilized to reduce erosion potential. These measures shall be incorporated into the final Drainage, Erosion, and Sedimentation Control Plan (DESCP) required

based on the draft DESCP (URS 2012b Attachment A116-1) under **SOILS-1**.

17. Monitor Ground Disturbing Activities Prior to Site Mobilization. If ground-disturbing activities are required prior to site mobilization, such as for geotechnical borings, grubbing or vegetation removal, ground water pump testing, or hazardous waste evaluations, the Designated Biologist or a Biological Monitor shall be present to monitor any actions that could disturb soil, vegetation, or wildlife.
18. Minimize Turbidity in Waterways. The Designated Biologist or Biological Monitor shall be present to monitor for indication of frac-outs and water turbidity during HDD activities beneath canals, or as otherwise required in the project's HDD Plan.
19. Control and Regulate Fugitive Dust. To reduce the potential for the transmission of fugitive dust the owner shall implement dust control measures **AQ-SC3, AQ-SC4, and AQ-SC2** the latter of which requires the preparation of an Air Quality Construction Mitigation Plan.

Verification: All mitigation measures and their implementation methods shall be included in the BRMIMP as described in **BIO-5** and implemented. Implementation of the measures shall be reported in the Monthly Compliance Reports by the Designated Biologist or Biological Monitor.

SAN JOAQUIN KIT FOX AND AMERICAN BADGER SURVEYS AND IMPACT AVOIDANCE MEASURES

BIO-7 Following USFWS's *Standardized Recommendations for Protection of the San Joaquin Kit Fox Prior to or During Ground Disturbance* (USFWS 2011), the project owner shall implement the following impact avoidance measures for San Joaquin kit fox and American badger:

1. Pre-construction Clearance Surveys. Each construction year or start of construction in a previously undisturbed area, the Designated Biologist shall perform a pre-construction survey for San Joaquin kit fox and American badger within all suitable habitat areas (i.e. saltbush scrub habitat, fallow agriculture lands, ruderal or barren lands, disturbed areas along canals, and all other areas not actively farmed) along linear facilities and the power plant site including a 200-foot buffer area or other CPM-approved survey buffer size based upon consultation with USFWS and CDFW . These surveys shall be conducted no less than 14 days and no more than 30 days prior to the beginning of ground disturbance and following federal survey protocol. The Designated Biologist or Biological Monitor shall systematically walk transects spaced 25 feet apart through all suitable habitat areas searching for kit fox/badger dens and sign. The status of dens (known, atypical, potential, natal/pupping) shall be determined and mapped with a GPS unit during the pre-construction surveys. All identified dens will be classified in accordance with USFWS's *Standardized Recommendations for Protection of the San Joaquin Kit Fox*

Prior to or during Ground Disturbance (USFWS 2011). The project owner shall submit a letter report summarizing the results of focused surveys including a figure showing any current den locations.

2. Den Exclusion Zones. Per USFWS 2011 impact avoidance guidelines, the project owner shall avoid dens identified during preconstruction surveys; the construction exclusion zone implemented around each kit fox den or badger den measured outward from the general cluster of den entrances. No disturbance to dens shall occur within the exclusion zone and Biological Monitors shall be present to monitor construction work closely around all potential dens and buffers. The minimum exclusion radius from construction activities is:

    - Potential and atypical den: exclusion zone of 50 feet or other CPM-approved exclusion zone based on consultation with CDFW and USFWS. Placement of 4 to 5 flagged stakes approximately 50 feet from the den entrances to identify the den location; fencing is not required.
    - Known den: exclusion zone of 100 feet with flagging or other CPM-approved exclusion zone based on consultation with CDFW and USFWS.
    - Natal/pupping den: the CDFW, USFWS to be consulted on appropriate exclusion zone distance or per the project's Biological Opinion.

3. Den Monitoring and Destruction of Unoccupied Dens. The Designated Biologist shall monitor all potential dens sites for evidence of kit fox activity. If potential kit fox dens of adequate size (generally 5 to 8 inches diameter) are found within the construction zone or within 200 feet of proposed work areas, the following den monitoring protocol shall be followed:

    a. Each potential den shall be assigned a number, marked with flagging in the field, and mapped with a GPS unit.

    b. All potential dens will be monitored for at least five consecutive days from the time of the observation to allow any resident animal to move to another den during its normal activity. Dens shall be monitored using a tracking medium and infrared camers. Tracking medium (usually gypsum powder) shall be evenly spread at the entrance to each potential den. The powder shall be inspected each morning between the hours of 0500 and 1000 for five consecutive days for tracks that might indicate kit fox or badger activity. Fresh gypsum powder shall be spread at the entrances during the monitoring phase to maintain a suitable tracking surface. In addition to tracking medium, each potential den shall be outfitted and monitored with an infrared camera station. Infrared cameras shall be checked and photos shall be downloaded daily.

After five consecutive days of negative findings of sign (tracks, scat, prey remains or matter vegetation in vicinity of den) and no kit fox or badger activity has been found on camera, the den shall be determined unoccupied and may then be excavated manually under the direction of the Designated Biologist. If the unoccupied den occurs within the 200-foot survey buffer area and not within the construction footprint, the den entrance shall be temporarily blocked with vegetation or loosely packed soil and not excavated or collapsed.

If kit fox or badger activity is observed at any point during the five-day monitoring period, the den-monitoring period shall re-start again for an additional five days. Once the Designated Biologist has determined that the potential den is not occupied by either a kit fox, badger, or other listed or special-status mammal, dens shall be fully excavated by hand, backfilled with soil, and compacted to prevent animals from entering it or using it, under the direction of the Designated Biologist. Natal or pupping dens shall not be destroyed, excavated, or disturbed until it has been determined that kit fox pups are independently foraging, are no longer dependent on the adults or family group, and all adults and pups have vacated the den. If at any point during excavation a kit fox or badger are discovered inside the den, the excavation activity shall cease immediately, USFWS, CDFW, and the CPM shall be notified, and monitoring of the den as described above shall resume.

4. <u>Other avoidance and minimization measures to be implemented during construction and operation</u> (per USFWS 2011 or more current agency San Joaquin kit fox guidance).

   a. Project-related vehicles shall observe a 20-mph speed limit on all paved roads in all non-public project areas (10-mph on dirt roads), except on county roads and state and federal highways. Off-road traffic outside of designated project areas shall be prohibited. Nighttime construction and truck deliveries shall be minimized to the extent possible and is prohibited along the carbon dioxide pipeline route; however, when it does occur, speed limits shall be reduced to 10 mph on project roadways.

   b. Any contractor or employee who is responsible for inadvertently killing or injuring a kit fox shall immediately report the incident to the Designated Biologist. If at any time an accidental death, injury, or entrapment of kit fox is discovered, the USFWS Sacramento Fish and Wildlife Office and CDFW Central Regional Office shall be notified in writing within three working days at the following location:

      Sacramento Fish and Wildlife Office

Endangered Species Division
2800 Cottage Way, Suite W2605
Sacramento, California 95825-1846
(916) 414-6620

California Department of Fish and Wildlife
Central Region
1234 East Shaw Ave.
Fresno CA 93710
(559) 243-4005

c. As described in **BIO-16**, all areas subject to temporary ground disturbances, including storage and staging areas, temporary roads, pipeline corridors, etc. shall be revegetated to promote restoration of the area to pre-project conditions. Appropriate methods and plant species used to revegetate such areas shall conform with the Revegetation Plan per **BIO-16**.

d.The Designated Biologist shall be the main point of contact source for any employee or contractor who might inadvertently kill or injure a kit fox or who finds a dead, injured or entrapped individual; the Designated Biologist and approved Biological Monitors shall be identified during the WEAP training and the Designated Biologist and list of approved Biological Monitors names and contact information shall be provided to USFWS.

e.The Designated Biologist(s) shall submit all observations of San Joaquin kit fox to CDFW's California Natural Diversity Database CNDDB within 60 calendar days of the observation and the Designated Biologist(s) shall include copies of the submitted forms with the next Monthly Compliance Report h.Reasonable effort shall be made to avoid damage and destruction of potential dens or burrows occupied by kit fox or other wildlife such as minimizing grading and disturbance to the minimal area required and minor re-location of project facility and pipeline routes.

5. <u>Compensatory Mitigation for San Joaquin Kit Fox.</u> Compensatory habitat shall be acquired for San Joaquin kit fox that meets selection criteria as mitigation for this species. Compensation lands shall be acquired as specified in **BIO-20** including requirements for the acquisition, initial habitat improvement, protection, and funding for long-term maintenance and management.

<u>Verification</u>: All San Joaquin kit fox and badger impact avoidance and minimization measures shall be incorporated into the BRMIMP as required under Condition of Certification **BIO-5.**

All kit fox/badger sign and den monitoring activities shall be reported in Monthly Compliance Reports including any copies of CNDDB reports that were submitted to CDFW within 60 days of the new sighting summarizing the results of any pre-construction clearance surveys for San Joaquin kit fox and American badger and the results of den monitoring activities. The Monthly Compliance Report shall include a map showing the location of all identified dens and exclusion zones.

Within 30 days of completing initial ground-disturbing preconstruction surveys or start of construction in a previously undisturbed area along a linear route, the project owner shall submit a letter report summarizing the results of the surveys to the CPM, CDFW, and USFWS, including a figure of potential dens and all den monitoring locations and buffers.

If a natal/pupping kit fox den is found in the construction area or within 200 feet of the proposed work areas, the Designated Biologist shall provide written notification to USFWS, CDFW, and CPM (within 24 hours of the finding).

If at any time a trapped injured, or deceased San Joaquin kit fox is discovered in the project area, the project owner shall notify the USFWS Sacramento Fish and Wildlife Office and CDFW Central Region office in writing within three working days with a notification copy to the CPM.

BLUNT-NOSED LEOPARD LIZARD TAKE AVOIDANCE AND MINIMIZATION MEASURES

BIO-8: The project owner shall implement the following as take and impact avoidance measures to blunt-nosed leopard lizard (BNLL) during construction and operation of the project.

1. Prepare a BNLL Impact Avoidance and Minimization Plan. The project owner shall prepare a BNLL Impact Avoidance and Minimization Plan outlining measures to implement during construction and operation of the project in order to avoid incidental take of this species as defined by Section 86 of the Fish and Game Code. Any modifications to the approved plan shall only take place after approval from the CPM, based on consultation with USFWS and CDFW. The plan shall discuss construction schedule details such as phasing preconstruction clearance and monitoring while taking into consideration that the power plant and linear facilities would likely be constructed in stages. In addition the plan shall include: plan purpose and goals; all construction impact avoidance measures (e.g. exclusion fencing and burrow monitoring) to ensure BNLL remain outside of the construction work areas; and long-term take avoidance measures and monitoring and reporting requirements to implement during project operation.
2. Pre-construction Surveys and Reporting. For each construction year or start of construction in a previously undisturbed area, the project owner shall conduct focused surveys for BNLL during the active period for this species following CDFW's *Approved Survey Methodology for the Blunt-nosed Leopard Lizard* (CDFG 2004). Suitable BNLL habitat areas are defined as all saltbush scrub and grassland habitat and disturbed, ruderal grassland areas that

contain the required habitat elements such as small mammal burrows, including streambeds, washes, and roads along all linear facility routes where BNLL has previously been observed. The project owner shall submit a letter report summarizing the results of focused surveys (CDFG 2004) including a figure showing any current BNLL observations.

The Designated Biologist(s) shall submit all observations of BNLL to CDFW's CNDDB within 60 calendar days of the observation and the Designated Biologist(s) shall include copies of the submitted forms with the next Monthly Compliance Report.

3. Qualifications of Surveyors. An acceptable BNLL survey crew shall consist of no more than three Level I researchers for every Level II researcher as defined in the *Approved Survey Methodology for the Blunt-nosed Leopard Lizard* (CDFG 2004). The names and affiliations of all researchers shall be recorded for each survey day.

   Level I: Researcher has demonstrated the ability to distinguish BNLL from other common lizard species that may inhabit the area;

   OR

   Level II: Researcher has demonstrated the ability to distinguish BNLL from other common lizard species that may inhabit the area and has participated in at least 50 survey days for BNLL (or 25 survey days and a BNLL identification course recognized by/acceptable to CDFW). Researcher has also made at least one confirmed field sighting of a BNLL.

4. Take Avoidance Measures. The Designated Biologist shall oversee implementation of all construction take avoidance measures outlined in the approved BNLL Impact Avoidance and Minimization Plan. The following shall be implemented during construction and incorporated into the Plan:

   a. The project owner shall conduct an initial BNLL burrow survey. Burrows that may be used by BNLL shall be avoided to the maximum extent feasible including minor re-location of project facilities including pipeline alignments.

   b. To the extent practicable and feasible, initial surface disturbance within suitable habitat and locations where BNLL have been observed before (i.e. Sites 1 through 5 along natural gas pipeline route, carbon dioxide pipeline, among others, **BIOLOGICAL RESOURCES Figure 2**), shall be scheduled during the active BNLL season (April 15 to October 15) to allow BNLL to escape.

   c. Initial surface disturbance activities that occur during the active BNLL season shall be monitored by the Designated Biologist. Subsequent to initial surface disturbance activities during the BNLL active season, Biological Monitors will not be required to be present during activities. If a BNLL is observed, it will be left alone and allowed to leave on its own and shall not be relocated.

d. In areas where BNLL have been observed or where burrows have been identified, temporary exclusion fencing shall be installed in a linear manner and shall not encircle any burrows. Fencings shall be a minimum 32-guage, 610mm aluminum sheeting, flashing, or other solid, rigid, non-climbing material and shall be staked at 2.5-meter intervals, with stakes facing the construction area. The fencing shall be buried at least 150mm (0.50 foot) below ground and extend at least 460 mm (1.5 feet) above ground. Any variance from these fence specifications requires approval from the CPM based on consultation with CDFW and USFWS. Vegetation will be trimmed as needed to prevent BNLL from climbing the exclusion fence. Once construction has completed in an area with exclusion fencing, the fencing shall be removed.

e. During the active season, areas underneath parked vehicles shall be inspected for BNLL prior to vehicle operation and if BNLL are observed under vehicles, the vehicle cannot be moved until BNLL has moved on its own.

5. <u>Compensatory Mitigation for Blunt-Nosed Leopard Lizard.</u> Compensatory habitat shall be acquired for BNLL that meets selection criteria as mitigation for this species. Compensation lands shall be acquired as specified in **BIO-20** including requirements for the acquisition, initial habitat improvement, protection, and funding for long-term maintenance and management.

<u>Verification</u>: At least 60 calendar days prior to the start of any project ground-disturbing activities, the project owner shall submit a draft BNLL Impact Avoidance and Minimization Plan to the CPM, USFWS, and CDFW for review and comments. At least 30 calendar days prior to the start of construction, the project owner shall submit a final BNLL Impact Avoidance and Minimization Plan that incorporates agency comments and input. The final plan shall be reviewed and approved by the CPM based on consultation with CDFW and USFWS. Any modifications to the final plan shall be made only after review and approval by the CPM, in consultation with USFWS and CDFW.

These blunt-nosed leopard lizard impact avoidance and minimization measures shall be incorporated into the BRMIMP as required under Condition of Certification **BIO-5**. A summary of all ongoing impact avoidance measures and results of all monitoring activities during construction and operation shall be included in the Monthly Compliance Reports along with a figure showing the location of any BNLL observations.

All BNLL observations shall be reported to the CNDDB within 60 days of the sightings with copies of the CNNDB submittal forms included in Monthly Compliance Reports.

For each construction year and/or start of construction in a previously undisturbed area along a linear facility route, the project owner shall submit a technical report to the CPM, USFWS, and CDFW, within 30 days following the completion of surveys summarizing the results of the focused BNLL survey.

SWAINSON'S HAWK IMPACT AVOIDANCE MEASURES

BIO-9 The project owner shall implement the following measures to minimize the potential for incidental take and impacts to Swainson's hawk during construction and operation of the project.

1. Prepare a Swainson's Hawk Monitoring and Mitigation Plan. The project owner shall prepare a Swainson's Hawk Monitoring and Mitigation Plan outlining measures to implement during construction and operation of the project in order to avoid incidental take of this species. Any modifications to the approved plan shall only take place after approval from the CPM, based on consultation with USFWS and CDFW. The approved plan shall discuss construction schedule details such as phasing preconstruction clearance and monitoring while taking into consideration that the power plant and linear facilities would likely be constructed in stages. In addition the plan shall include: plan purpose and goals; pre-construction surveys and construction impact avoidance and minimization measures including nest buffers; nest monitoring methods to employ in order to gauge disturbance levels to nests and occupants during construction; long-term take avoidance measures to implement during project operation; and long-term monitoring and reporting of Swainson's hawk impact avoidance measures during commercial operation.

2. Preconstruction Surveys. Prior to the start of any project-related ground disturbance activities, the project owner shall conduct focused, preconstruction surveys for Swainson's hawk nests. The goal of the nesting surveys shall be to identify the location of nest sites and to establish an adequate protective buffer zone around the nest tree. If any ground-disturbing activities are scheduled to begin during the nesting bird season (February 1 to August 31), the surveyors shall perform surveys in accordance with the following guidelines:

    a. Surveys shall cover all potential nesting within the project site and along all linear facilities including a 0.50-mile survey radius (Swainson's Hawk Technical Advisory Committee 2000) or other survey boundary approved by the CPM based on consultation with CDFW. Surveys shall be conducted from one hour before sunrise to two hours after sunrise and shall conclude by 1030 at the latest. All nest trees identified in Figure A45-2, Swainson's Hawk Observations Near the Project Area (URS 2012a) shall be subject to preconstruction surveys and any other suitable nest trees located within a 0.50-mile radius around the project site and along linear routes.

b. At least two pre-construction surveys shall be conducted, separated by a minimum 10-day interval. One of the surveys shall be conducted within a 14-day period preceding the initiation of any project-related ground disturbing activity. If more than 30 days lapses between the second nesting bird survey and the start of construction, additional survey(s) shall be performed.

3. <u>Nest Buffers from Construction Activities</u>. In accordance with CDFW's *Staff Report Regarding Mitigation for Impacts to Swainson's Hawks (Buteo swainsoni) in the Central Valley of California* (CDFG 1994), no new intensive disturbances or project-related activities which may cause nest abandonment or forced fledging shall be initiated within 0.50 mile of an active nest or other CPM-approved nest avoidance buffer size based on consultation with CDFW between March 1 to September 15 of any construction year. If construction or other project–related activities, which may cause nest abandonment or forced fledgling are necessary within the 0.50-mile buffer zone, the Designated Biologist or Biological Monitor shall monitor the nest site in accordance with the approved Swainson's Hawk Impact Avoidance and Minimization Plan.

4. <u>Compensatory Mitigation for Loss of Swainson's Hawk Foraging Habitat.</u> Compensatory habitat shall be acquired for Swainson's hawk that meets selection criteria as mitigation for this species. Compensation lands shall be acquired as specified in **BIO-20** including requirements for the acquisition, initial habitat improvement, protection, and funding for long-term maintenance and management. Lands under an existing Williamson Act contract shall not be considered suitable mitigation lands for Swainson's hawks.

<u>Verification</u>: At least 60 calendar days prior to the start of any project ground-disturbing activities, the project owner shall submit a draft Swainson's Hawk Monitoring and Mitigation Plan to the CPM and CDFW for review and comments. At least 30 calendar days prior to the start of construction, the project owner shall submit a final Swainson's Hawk Monitoring and Mitigation Plan that incorporates agency comments and input. The final plan shall be reviewed and approved by the CPM based on consultation with CDFW. Any modifications to the final plan shall be made only after review and approval by the CPM, in consultation with CDFW.

These impact avoidance and minimization measures shall be incorporated into the BRMIMP as required under Condition of Certification **BIO-5**. A summary of all ongoing impact avoidance and results of all monitoring activities during construction and operation shall be included in the Monthly Compliance Reports, including a figure showing all nests and nest monitoring locations. All Swainson's hawk observations shall be reported to the CNDDB within 60 days of the sightings with copies of the CNNDB submittal forms included in Monthly Compliance Reports.

Within 30 days following the completion of preconstruction nest surveys for Swainson's hawk, the project owner shall submit a technical report summarizing the results of the preconstruction surveys to the CPM with a copy to CDFW. If an active Swainson's hawk nest is found within the approved survey area of the project site, the Designated Biologist shall notify the CPM and CDFW in writing within two business days.

MITIGATION FOR MIGRATORY BIRD TREATY ACT AND CALIFORNIA FISH AND GAME CODE PROTECTED AVIAN SPECIES

BIO-10 The project owner shall implement the following measures in order to minimize the potential for impacts to nesting birds protected by the Migratory Bird Treaty Act and California Fish and Game Code Sections 3503 (regarding unlawful "take," possession or needless destruction of the nest or eggs of any bird), 3503.5 (regarding the "take," possession or destruction of any birds-of-prey or their nests or eggs), and 3513 (regarding unlawful "take" of any migratory nongame bird):

1. Preconstruction Nest Surveys and Construction Avoidance Buffers. For each construction year or prior to the start of construction in a new project area, the Designated Biologist and/or Biological Monitor(s) shall perform pre-construction nest surveys if any construction activities would occur anytime during the nesting season (February 1 through August 31). The Designated Biologist or Biological Monitor conducting the surveys shall be experienced bird surveyors familiar with standard nest-locating techniques such as those described in Martin and Geupel (1993). The goal of the nesting surveys shall be to identify the general location of the nest sites in order to establish a protective buffer zone around nest sites.

a. Surveys shall be conducted prior to construction and shall cover all potential nesting habitat in the project site and linear facilities, including the construction footprint and a minimum 200-foot survey buffer. Songbird nest surveys shall be conducted no earlier than one hour before sunrise and within two hours following sunrise and shall conclude by 10:30 a.m.

b. At least two pre-construction surveys shall be conducted, separated by a minimum 10-day interval. One of the surveys shall be conducted within a 14-day period preceding initiation of construction activity. Additional follow-up surveys shall be required if periods of construction inactivity exceed 30 days.

No additional measures shall be implemented if active nests are more than the following distances from the nearest work site: (a) 500 feet for raptors, or (b) 250 feet for passerine birds. The specified buffer size may be reduced on a case-by-case basis if, based on compelling biological or ecological reasoning (e.g. the biology of the bird species, concealment of the nest site by topography, land use type, vegetation, and level of project activity) and as determined by the Designated Biologist, that implementation of a specified smaller buffer distance shall still avoid project-related “take” (as defined by Fish and Game Code Section 86) of adults, juveniles, chicks, or eggs associated with a particular nest. The nests shall be continually monitored for the duration of the nesting season by the Designated Biologist or Biological Monitor unless it has been determined that the young have fledged, are no longer dependent upon parental care, or construction ends (whichever occurs first). If the nesting birds show signs of distress with a reduced buffer size during project activities, the Designated Biologist shall I contact the CPM (in consultation with CDFW and USFWS) and reinstate the recommended buffers. Buffers shall not apply to construction related traffic using existing roads that is not limited to project-specific use (i.e., county roads, highways, farm roads, etc.). Non-listed species found building nests within the standard buffer zone after specific project activities begin shall be assumed tolerant of that specific project activity and the nest will be protected by the maximum buffer practicable. However, these nests should be regularly monitored for the duration of the nesting season until the Designated Biologist or Biological Monitor has determined that the young have fledged, are no longer dependent upon parental care, or construction ends (whichever occurs first). If the nesting birds show signs of distress with a reduced buffer size during project activities, the qualified wildlife biologist shall contact the CPM (in consultation with CDFW and USFWS) and reinstate the recommended buffers.

2. Retention Pond Netting. The project owner shall cover the retention ponds, prior to any ponds becoming operational, with 1.5-inch mesh netting designed to exclude birds and other wildlife from drinking or landing on the water of the ponds. Netting with mesh sizes other than 1.5-inches may be installed if approved by the CPM in consultation with CDFW and USFWS. The netted ponds shall be monitored regularly to verify that the netting remains intact, is fulfilling its function in excluding birds and other wildlife from the ponds, and does not pose an entanglement threat to birds and other wildlife. The ponds shall include a visual deterrent in addition to the netting, and the pond shall be designed such that the netting shall never contact the water.

a. Monthly Monitoring. The Designated Biologist or Biological Monitor shall regularly survey the ponds at least once per month starting with the first month of operation of the evaporation ponds. The purpose of the surveys shall be to determine if the netted ponds are effective in excluding birds, if the nets pose an entrapment hazard to birds and wildlife, and to assess the structural integrity of the nets. The monthly survey shall be conducted in one day for a minimum of two hours following sunrise (i.e., dawn), a minimum of one hour mid-day (i.e., 1100 to 1300), and a minimum of two hours preceding sunset (i.e., dusk) in order to provide an accurate assessment of bird and wildlife use of the ponds during all seasons. Surveyors shall be experienced with bird identification and survey techniques. Operations staff at the project site shall also report finding any dead birds or other wildlife at the evaporation ponds to the Designated Biologist within one day of the detection of the carcass. The Designated Biologists shall report any bird or other wildlife deaths or entanglements within two days of the discovery to the CPM, CDFW, and USFWS.

b. Dead or Entangled Birds. If dead or entangled birds are detected, the Designated Biologist shall take immediate action to correct the source of mortality or entanglement. The Designated Biologist shall make immediate efforts to contact and consult the CPM, CDFW, and USFWS by phone and electronic communications prior to taking remedial action upon detection of the problem, but the inability to reach these parties shall not delay taking action that would, in the judgment of the Designated Biologist, prevent further mortality of birds or other wildlife at the evaporation ponds.

c. Quarterly Monitoring. If after 12 consecutive monthly site visits no bird or wildlife deaths or entanglements are detected at the evaporation ponds by or reported to the Designated Biologist, monitoring, as described in paragraph 1, can be conducted on a quarterly basis.

d. Biannual Monitoring. If after 12 consecutive quarterly site visits no bird or wildlife deaths or entanglements are detected by or reported to the Designated Biologist and with approval from the CPM, USFWS and CDFW, future surveys may be reduced to two surveys per years, during the spring nesting season and during fall migration. If approved by the CPM, USFWS and CDFW, monitoring outside the nesting season may be conducted by the Environmental Compliance Manager.

e. Modification of Monitoring Program. CDFW or USFWS may submit a request for modifications to the evaporation pond monitoring program based on information acquired during monitoring, and may also suggest adaptive management measures to remedy any problems that are detected during monitoring or modifications if bird impacts are not observed. Modifications to the evaporation pond monitoring described above and implementation of adaptive management measures shall be made only after approval from the CPM, in consultation with USFWS and CDFG.

Verification: All mitigation measures and their implementation methods shall be included in the BRMIMP as required under Condition of Certification **BIO-5**. Implementation of the measures will be reported in the Monthly Compliance Reports by the Designated Biologist.

At the end of each nesting season during each construction year, the project owner shall submit a written report documenting any variance from the standard buffers to the CPM, USFWS, and CDFW that includes the species, location, reason for the buffer reduction, the name and contact information of the Designated Biologist who authorized the buffer reduction and conducted subsequent monitoring, the reduced avoidance buffer size, duration of buffer reduction, and outcome to the nest, egg, young, and adults. The report shall also summarize the results of the pre-construction nesting bird surveyand include the time, date, and duration of the survey; identity and qualifications of the surveyor (s); and a list of species observed. If active or suspected active nests are detected during the survey, the report shall include a map or aerial photo identifying the location of the nest or suspected nest location and implemented buffer.

No less than 30 days prior to operation of the retention ponds the project owner shall provide to the CPM as-built drawings and photographs of the ponds indicating that the bird exclusion netting has been installed. For the first year of operation the Designated Biologist shall submit quarterly reports to the CPM, CDFW, and USFWS describing the dates, durations and results of site visits conducted at the evaporation ponds. Thereafter the Designated Biologist shall submit annual monitoring reports with this information. The quarterly and annual reports shall fully describe any bird or wildlife death or entanglements detected during the site visits or at any other time, and shall describe actions taken to remedy these problems. The annual report shall be submitted to the CPM, CDFW, and USFWS no later than January 31st of every year for the life of the project.

BURROWING OWL IMPACT AVOIDANCE AND MINIMIZATION MEASURES

BIO-11 The project owner shall implement the following measures to avoid and minimize impacts to burrowing owls:

1. <u>Prepare a Burrowing Owl Monitoring and Mitigation Plan</u>. The project owner shall prepare and implement a Burrowing Owl Monitoring and Mitigation Plan that incorporates the most recent mitigation guidance on this species (CDFG 2012b). Any modifications to the approved plan shall only take place after approval from the CPM based on consultation with CDFW.

   At a minimum the plan shall include the following: plan purpose and goals; a discussion of take avoidance measures including preconstruction survey methods; burrow monitoring methods; a discussion of all impact avoidance and minimization measures to employ prior to implementing passive relocation and burrow eviction as a last option; a discussion of scenarios in which passive relocation would be necessary; identify and describe suitable relocation sites; potential use of artificial burrows if passive relocation is necessary; monitoring and management of relocation sites and any installed artificial burrows; and long-term monitoring and reporting requirements during operation.

2. <u>Pre-Construction Surveys</u>. For each construction year or prior to the start of ground disturbing activities in a previously undisturbed area, the Designated Biologist or Biological Monitor(s) shall conduct focused surveys for burrowing owls no more than 30 days prior to initiation of construction activities. Surveys shall be focused exclusively on detecting burrowing owls, and shall be conducted

from two hours before sunset to one hour after or from one hour before to two hours after sunrise. The survey area shall include the proposed construction areas and a surrounding 500-foot survey buffer.

3. Implement Impact Avoidance Measures. To the extent feasible, impacts to occupied burrows will be minimized during the nesting season, from February 1 through August 31 of any given year. If an active burrowing owl burrow is detected within the construction work zones or a 500-foot survey buffer, the following avoidance and minimization measures shall be implemented:

   a. Establish Non-Disturbance Buffer. If construction commences during the burrowing owl nesting season (February 1 through August 31), either buffer zones, visual screens, or other approved measures shall be implemented and based on site-specific conditions, the results of preconstruction owl surveys, and any follow up monitoring surveys of occupied burrows. Buffer sizes shall be determined based on the time of year and level of disturbance identified in the *Staff Report on Burrowing Owl Mitigation* (CDFG 2012b). Buffer sizes shall be installed in accordance with the approved Burrowing Owl Monitoring and Mitigation Plan with a minimum buffer size of 200 meters, or other CPM-approved buffer size, during the peak nesting season. Materials used to identify non-disturbance buffers shall not preclude access or disturb access of the burrow by owls. The non-disturbance buffer shall be identified as an “Environmentally Sensitive Area” in the construction area. Signs shall be posted in English and Spanish at the fence line indicating no entry or disturbance is permitted within the fenced buffer.

   b. Monitoring: If construction activities would occur within 500 feet of any identified occupied burrows during the nesting season (February 1 – August 31) the Designated Biologist or Biological Monitor shall monitor the occupied burrow in accordance with the approved Burrowing Owl Monitoring and Mitigation Plan to determine if these activities are adversely affecting burrowing owl nesting behaviors.

4. Compensatory Mitigation for Burrowing Owl. Compensatory habitat shall be acquired for burrowing owl that meets selection criteria as mitigation for this species. Compensation lands shall be acquired as specified in **BIO-20** including requirements for the acquisition, initial habitat improvement, protection, and funding for long-term maintenance and management.

Verification: At least 60 calendar days prior to the start of any project ground-disturbing activities, the project owner shall submit a draft Burrowing Owl Monitoring and Mitigation Plan to the CPM and CDFW for review and comment. At least 30 calendar days prior to the start of construction, the project owner shall submit a final Burrowing Owl Monitoring and Mitigation Plan that incorporates agency comments and input. The final plan shall be reviewed and approved by the CPM based on consultation with CDFW. Any modifications to the final plan shall be made only after review and approval by the CPM, in consultation with CDFW.

All mitigation measures and their implementation methods shall be included in the BRMIMP as required under Condition of Certification **BIO-5**. Implementation of the measures shall be reported in the Monthly Compliance Reports by the Designated Biologist.
These impact avoidance and minimization measures shall be incorporated into the BRMIMP as required under Condition of Certification **BIO-5**. A summary of all ongoing impact avoidance and results of all monitoring activities during construction shall be included in the Monthly Compliance Reports, including a figure showing all burrows and burrow monitoring locations. All burrowing owl observations shall be reported to the CNDDB within 60 days of the sightings with copies of the CNNDB submittal forms included in Monthly Compliance Reports.

Within 30 days following the completion of preconstruction nest surveys for burrowing owl in a new construction area, the project owner shall submit a letter report summarizing the results of the preconstruction surveys to the CPM with a copy to CDFW. If an active burrowing owl occupied burrow is found within the approved survey area of the project site, the Designated Biologist shall notify the CPM and CDFW in writing within two business days.

SMALL MAMMAL RELOCATION PLAN

BIO-12 The project owner shall prepare and implement a Small Mammal Relocation Plan for listed small mammals that will outline measures to avoid mortality of Tipton kangaroo rat, San Joaquin antelope squirrel, giant kangaroo rat, and other small mammals during construction and operation of the project. Relocation activities shall not proceed until the Small Mammal Relocation Plan has been approved in writing by the CPM, in consultation with USFWS and CDFW. Once the relocation plan is approved by the CPM, it may be used for all San Joaquin antelope squirrel, Tipton kangaroo rat, and giant kangaroo rat relocation activities for the duration of the project.

The approved plan shall discuss construction schedule details such as phasing pre-activity burrow surveys and trapping efforts while taking into consideration that the power plant and linear facilities would likely be constructed in stages. In addition the plan shall include: plan purpose and goals; measures to avoid take during construction including preconstruction surveys and trapping and relocation protocols; permitting requirements for those approved to handle listed small mammals; identification of potential release sites and minimum qualifications for such sites; monitoring and reporting of small mammals at release sites; and long-term take avoidance measures during commercial operation for listed small mammals.

Verification: At least 60 calendar days prior to the start of any project ground-disturbing activities, the project owner shall submit a draft Small Mammal Relocation Plan to the CPM, CDFW, and USFWS for review and comment. At least 30 calendar days prior to the start of construction, the project owner shall submit a final Small Mammal Relocation Plan that incorporates agency comments and input. The final plan shall be reviewed and approved by the CPM based on consultation with CDFW and USFWS. Any modifications to the final plan shall be made only after review and approval by the CPM, in consultation with CDFW and USFWS.

GIANT KANGAROO RAT IMPACT AVOIDANCE MEASURES

BIO-13 The project owner shall implement the following measures prior to ground disturbing activities to avoid and minimize impacts to burrowing mammals specifically giant kangaroo rat:

1. Giant Kangaroo Rat (GKR) Precinct Avoidance. GKR precincts shall be avoided to the maximum extent practicable. If earthwork (e.g., clearing, grubbing, blading, scraping, excavating, filling) must occur within GKR precincts, these areas shall be live trapped by the Designated Biologist prior to the initiation of ground-disturbing activities to minimize direct mortality. The Biological Monitors conducting the giant kangaroo rat precinct survey must have demonstrated experience in identifying sign of this species and specifically be approved by the CPM in consultation with CDFW and USFWS prior to conducting precinct surveys in suitable habitat areas.

   Daytime transects shall be conducted at 30 to 100 foot intervals and transect width will be adjusted based on vegetation height (USFWS 2007). The purpose of this survey is to identify precinct, giant kangaroo rat presence, and small mammal burrows that will be used to aid in defining the small mammal trapping area.

2. GKR Trapping and Burrow Excavation. Following the giant kangaroo rat precinct survey and prior to construction activities beginning in a previously undisturbed suitable habitat area, the Designated Biologist shall oversee small mammal trapping and relocation in accordance with the approved Small Mammal Relocation Plan. GKR shall be trapped and relocated to the CPM-approved release site identified in the approved Small Mammal Relocation Plan. Following live-trapping activities, any potential GKR burrows present within the portion of the project site to be disturbed by earthwork (e.g., clearing, grubbing, blading, scraping, excavating, filling) shall be fully excavated by hand by the Designated Biologist to allow any remaining GKR an opportunity to escape or be captured by hand as necessary (this condition does not apply to precincts that would be disturbed only by foot traffic or rubber-tired vehicle traffic). Any GKR encountered in the excavated burrows shall be relocated to the CPM-approved release site described in the approved Small Mammal Relocation Plan. Dormant or torpid GKR encountered shall also be collected and

moved to an artificial burrow installed at the approved release site. “Soft-release” methods in cages with artificially constructed burrows shall be used at receiver sites. GKR neighbor relationships (location and distance of individual burrows relative to one another) shall be maintained when moving all or some GKR from a given precinct.

Haystacks, seed caches, and seed stores found with live-trapped GKR, or in excavated burrows, shall be relocated with the associated individual GKR, and shall be placed within the release cages and artificial burrows.

Protection of GKR Food Stores. Where temporary impacts occur that do not warrant salvage of GKR, as directed by the Small Mammal Relocation Plan, any haystacks, seed caches, or other forage stockpiled by GKR on the ground surface shall be left undisturbed to the greatest extent practicable. If avoidance is not possible, the approved GKR monitor or Designated Biologist shall implement measures to keep the food stores intact, including temporary relocation of the food stores (only in the daytime; seeds must be returned to original location for the night), cover the seeds with plywood to allow temporary vehicle or foot-traffic access, or implement other measures developed CPM in consultation with CDFW.

3. Data Collection. The Designated Biologist shall maintain a record of all giant kangaroo rats and any other common or special-status small mammals captured. The information collected for each animal includes: a) the locations (Global Positioning System [GPS] coordinates and maps) and time of capture and/or observation as well as release; b) sex; c) approximate age (adult/juvenile); d) weight; e) general condition and health, noting all visible conditions including gait and behavior, diarrhea, emaciation, salivation, hair loss, ectoparasites, and injuries; and f) ambient temperature when handled and released. A relocation summary shall be prepared and included in the Monthly Compliance Reports and shall at a minimum include an analysis of data collected, conclusions, and recommendations.

4. Notification. If a giant kangaroo rat is injured as a result of project-related activities, it shall be immediately taken to a CDFW and USFWS-approved wildlife rehabilitation or veterinary facility. The project owner shall identify the facility prior to the start of ground- or vegetation-disturbing activities in the Small Mammal Relocation Plan. The project owner shall bear any costs associated with the care or treatment of such injured giant kangaroo rat.

5. <u>Compensatory Mitigation for Giant Kangaroo Rat</u>. Compensatory habitat shall be acquired for giant kangaroo rat that meets selection criteria as mitigation for this species. Compensation lands shall be acquired as specified in **BIO-20** including requirements for the acquisition, initial habitat improvement, protection, and funding for long-term maintenance and management.

<u>Verification</u>: The project owner shall submit the resume, field experience, and qualifications of the GKR precinct surveyor at least 60 days prior to the start of any project-related ground disturbance activities occurring in GKR suitable habitat for review and approval to the CPM with copies to USFWS and CDFW.

These impact avoidance and minimization measures shall be incorporated into the BRMIMP as required under Condition of Certification **BIO-5**. A summary of all ongoing impact avoidance and results of all monitoring activities during construction shall be included in the Monthly Compliance Reports including a figure showing all small mammal burrows and trapping areas. All observations of GKR and any other special-status mammal shall be reported to the CNDDB within 60 days of the sightings with copies of the CNNDB submittal forms included in Monthly Compliance Reports.

For each construction year and/or construction phase, the project owner shall submit a final report to the CPM, CDFW, and USFWS at least 10 days prior to the start of any ground disturbing activities or construction equipment staging summarizing the results of the small mammal survey, trapping, and relocation activities. The report shall include a relocation summary including data collected during surveys and trapping for giant kangaroo rat.

If a giant kangaroo rat is injured during project-related activities, the project owner shall notify the CPM, CDFW, and USFWS immediately unless the incident occurs outside of normal business hours. In that event, CDFW, USFWS, and CPM shall be notified no later than noon on the next business day. Notification to CDFW, USFWS, and CPM shall be via telephone or email, followed by a written incident report. Notification shall include the date, time, location and circumstances of the incident and the name of the facility where the animal was taken.

TIPTON KANGAROO RAT AND SAN JOAQUIN ANTELOPE GROUND SQUIRREL IMPACT AVOIDANCE MEASURES

BIO-14 The project owner shall implement the following measures prior to ground disturbing activities to avoid and minimize impacts to burrowing mammals specifically Tipton kangaroo rat and San Joaquin antelope squirrel:

1. <u>Focused Burrow Survey</u>. In accordance with the approved Small Mammal Relocation Plan per **BIO-12** and prior to the start of ground disturbing activities within previously undisturbed suitable habitat areas (i.e. saltbush scrub habitat, non-native grassland, fallow agriculture lands, ruderal or barren lands, disturbed areas along canals, and all other areas not actively farmed) the

Designated Biologist or approved Biological Monitors shall conduct walking surveys to identify small mammal burrows that occur in the construction work zones. Daytime transects shall be conducted at 30 to 100 foot intervals and transect width will be adjusted based on vegetation height (USFWS 2007). The purpose of this survey is to identify small mammal burrows to aid in defining the small mammal trapping area.

2. Small Mammal Trapping and Relocation. Within 30 days prior to the estimated start of construction activities, the Designated Biologist and Biological Monitors shall conduct live trapping in the areas identified with small mammal burrows. The trapping protocol, trapping conditions, and relocation activities shall be performed in accordance with the approved Small Mammal Relocation Plan per **BIO-12**. San Joaquin antelope squirrels, Tipton kangaroo rats and other special-status mammals shall be trapped and relocated to the agency-approved release site only after young of the year are observed above ground and during the main activity period for San Joaquin antelope squirrel (April 1 to September 30) and the main activity period for Tipton kangaroo rat (April 1 to June 30).

   Following live trapping activities, any potential San Joaquin antelope squirrel and Tipton kangaroo rat burrows present within the portion of the project site or along project linear facilities shall be fully excavated by hand by the Designated Biologist. Any San Joaquin antelope squirrels, Tipton kangaroo rat, or other small mammals encountered in the excavated burrows during their active period shall be allowed to escape to the adjacent natural habitat or if captured shall be relocated to the CPM-approved release site. Any dormant San Joaquin antelope squirrels, Tipton kangaroo rats, or other special-status mammals encountered shall be collected and moved to an artificial burrow installed at the agency-approved release site.

3. Data Collection. The Designated Biologist shall maintain a record of all San Joaquin antelope squirrels, Tipton kangaroo rats and any other common or special-status small mammals captured. The information collected for each animal includes: a) the locations (Global Positioning System [GPS] coordinates and maps) and time of capture and/or observation as well as release; b) sex; c) approximate age (adult/juvenile); d) weight; e) general condition and health, noting all visible conditions including gait and behavior, diarrhea, emaciation, salivation, hair loss, ectoparasites, and injuries; and f) ambient temperature when handled and released. A relocation summary shall be prepared and included in the Monthly Compliance Report and shall at a minimum include an analysis of data collected, conclusions, and recommendations.

4. <u>Notification.</u> If a San Joaquin antelope squirrel or Tipton kangaroo rat is injured as a result of project-related activities, it shall be immediately taken to a CDFW and/or USFWS-approved wildlife rehabilitation or veterinary facility. The project owner shall identify the facility prior to the start of ground- or vegetation-disturbing activities in the Small Mammal Relocation Plan. The project owner shall bear any costs associated with the care or treatment of such injured San Joaquin antelope squirrel or Tipton kangaroo rat.

5. <u>Compensatory Mitigation for Tipton Kangaroo Rat and San Joaquin Antelope Ground Squirrel</u>. Compensatory habitat shall be acquired for Tipton kangaroo rat and San Joaquin antelope squirrel that meets selection criteria as mitigation for these species. Compensation lands shall be acquired as specified in **BIO-20** including requirements for the acquisition, initial habitat improvement, protection, and funding for long-term maintenance and management.

<u>Verification</u>: These impact avoidance and minimization measures shall be incorporated into the BRMIMP as required under Condition of Certification **BIO-5**. A summary of all ongoing impact avoidance and results of all monitoring activities during construction shall be included in the Monthly Compliance Reports including a figure showing all small mammal burrows and trapping areas. All observations of Tipton kangaroo rat, San Joaquin antelope squirrel and any other special-status mammal shall be reported to the CNDDB within 60 days of the sightings with copies of the CNNDB submittal forms included in Monthly Compliance Reports.

For each construction year and/or construction phase, the project owner shall submit a final pre-activity report to the CPM, CDFW, and USFWS at least 10 days prior to the start of any ground disturbing activities or construction equipment staging summarizing the results of the small mammal survey, trapping, and relocation activities. The report shall include a relocation summary including data collected during surveys and trapping for San Joaquin antelope squirrel and Tipton kangaroo rat.

If a San Joaquin antelope squirrel or Tipton kangaroo rat is injured during project-related activities, the project owner shall notify the CPM, CDFW, and USFWS immediately unless the incident occurs outside of normal business hours. In that event, CDFW, USFWS, and CPM shall be notified no later than noon on the next business day. Notification to CDFW, USFWS, and CPM shall be via telephone or email, followed by a written incident report. Notification shall include the date, time, location and circumstances of the incident and the name of the facility where the animal was taken.

GIANT GARTER SNAKE IMPACT AVOIDANCE MEASURES

BIO-15 The project owner shall implement the following measures during construction to avoid and minimize the potential for impacts to giant garter snake (GGS) that may occur in the project area.

1. Preconstruction Surveys for GGS. No more than 24 hours prior to ground disturbing activities, the Designated Biologist shall survey the work areas within potential giant garter snake habitat for giant garter snakes. Surveys of work areas shall be repeated if a lapse in construction activity of 48 hours or greater has occurred. The results of this preconstruction survey shall be reported to the CPM, USFWS, and CDFW, even if no snakes are observed (USFWS 1997, Appendix C). Suitable habitat areas to be surveyed include all linear construction rights-of-way along irrigation canal banks (i.e. processed water pipeline along West Side Canal and portion of railroad spur and natural gas pipeline along East Side Canal).
2. Biological Monitor Presence During Construction. Following completion of preconstruction survey(s), an approved Biological Monitor shall be present and monitoring during all construction activities within 200 feet of aquatic irrigation canal habitat. Prior to the start of construction along irrigation canals, the immediate construction areas shall be surveyed and cleared each construction day. The Designated Biologist will ensure that all measures related to GGS are followed and have the authority to stop construction if they are not. Any open trenches along linear facility construction routes will be inspected daily for trapped snakes

<u>Verification</u>: All mitigation measures and their implementation methods shall be included in the BRMIMP as required under Condition of Certification **BIO-5**. A summary of all ongoing impact avoidance and results of all monitoring activities during construction and operation shall be reported in the Monthly Compliance Reports.

Within 10 days following the completion of a preconstruction clearance surveys for giant garter snake or start of construction in previously undisturbed habitat, the project owner shall submit a letter report summarizing the results of the preconstruction surveys to the CPM, CDFW, and USFWS.

MITIGATION FOR WESTERN SPADEFOOT TOAD

BIO-16 The project owner shall implement the following measures to avoid and minimize impacts to western spadefoot toad.

<u>Fencing and Avoidance of Potential Breeding Areas</u>: Prior to the start of any project-related ground disturbance along a linear route in a previously undisturbed area, the Designated Biologist shall establish Environmentally Sensitive Areas (ESAs) around all identified potential spadefoot toad breeding areas that occurwithin 100 feet of project construction areas, including the single wetland depression where spadefoot toad tadpoles were found during previous biological field surveys between the West Side Canal and California Aqueduct (HEI 2009a). The locations of ESAs shall be clearly depicted on construction drawings, which shall also include a list of impact avoidance and minimization measures on the construction plans. The boundaries of the

ESAs shall be placed a minimum of 20 feet from the uphill side of the occurrence and 10 feet from the downhill side or as otherwise approved by the CPM and shall be clearly delineated in the field with temporary construction fencing and signs prohibiting movement of the fence. ESAs shall also be permanently marked (with signage or other markers) to ensure that avoided habitat areas are not inadvertently harmed during construction and operation.

<u>Verification</u>: All mitigation measures and their implementation methods shall be included in the BRMIMP as required under Condition of Certification **BIO-5**. Implementation of the above impact avoidance and minimization measures will be reported in the Monthly Compliance Reports by the Designated Biologist.

Any observations of western spadefoot toad shall be reported in Monthly Compliance Reports including any copies of CNDDB reports that were submitted to CDFW within 60 days of the new sighting.

No less than 30 days prior to the start of ground-disturbing activities and following the habitat assessment, the Designated Biologist shall establish Environmentally Sensitive Areas (ESAs) around all identified potential spadefoot toad breeding areas that occur outside and within 100 feet of project construction areas. No less than 10 days prior to the start of any project-related ground disturbing activities, the project owner shall submit grading plans and/or construction drawings to the CPM with the locations of all spadefoot toad potential breeding areas and fenced Environmentally Sensitive Areas areas.

SPECIAL-STATUS PLANT SPECIES IMPACT AVOIDANCE MEASURES

BIO-17 The project owner shall perform the following measures to avoid impacts to special-status plants during construction and operation of the project:

1. <u>Focused Botanical Surveys.</u> Prior to the start of any project-related ground disturbance in a previously undisturbed area along a linear route, the Designated Biologist and/or Biological Monitors shall conduct focused botanical surveys according to CDFW's *Protocols for Surveying and Evaluating Impacts to Special-Status Native Plant Populations and Natural Communities* (CDFG 2009). All suitable habitat areas to be directly or indirectly impacted by the project shall be surveyed prior to disturbance and at a minimum will include the entire carbon dioxide pipeline route and Sites 1 through 5 shown on **Biological Resources Figure 2** along the natural gas pipeline route including a minimum 200-foot survey buffer or other CPM-approved survey buffer. Survey results shall be submitted to the CPM, USFWS, and CDFW and will include all information contained under 'Botanical Survey Reports' identified in CDFW's field survey protocol for floristic surveys (CDFG 2009).

2. <u>Implement Construction Impact Avoidance, Minimization Measures, and Site Design Modifications</u>:

    a. Incorporate site design modifications to minimize impacts to special-status plants along the project linear routes. All identified occurrences (populations and individual plants) of CNPS List 1B and List 4 plants species shall be avoided by project construction and grading to the maximum extent feasible. The project owner shall limit the width of the work area by: adjusting the location of staging areas, lay down areas, spur roads, and transmission poles or towers; and minor adjustments to the alignment of the roads and pipelines within the constraints of linear facilities rights-of-way.

b. Establish Environmentally Sensitive Areas. The Designated Biologist shall establish Environmentally Sensitive Areas (ESAs) to protect avoided special-status plants that occur outside but within 200 feet of construction work zones. ESAs shall be clearly delineated in the field with temporary construction fencing and signage indicating construction activities are not permitted inside the ESA fencing. The locations of ESAs shall be clearly depicted on construction drawings. Areas for spoils, equipment, vehicle parking, maintenance and washing, and material storage shall be placed at least 100 feet from any ESAs.

c. The Designated Biologist shall oversee compliance with all special-status plant impact avoidance, minimization, and compensation measures described in this condition throughout construction and shall monitor for the protection of special-status plant occurrences within 200 feet of the project boundaries that will be identified and fenced as ESAs.

d. Erosion and Sediment Control Measures. Erosion and sediment control measures shall not inadvertently impact special-status plants (e.g., by using invasive or non-native plants in seed mixes, introducing pest plants through contaminated seed or straw, etc.). These measures shall be incorporated in the Drainage, Erosion, and Sedimentation Control Plan required in **SOILS-1**.

e. The Designated Biologist shall oversee and train all other Biological Monitors tasked with monitoring around plant ESAs.

<u>**Verification**</u>**:** These special-status plant impact avoidance and minimization measures shall be incorporated into the BRMIMP as required under Condition of Certification **BIO-5** and reported in Monthly Compliance Reports.

For each construction year and/or construction phase, if Kern mallow or other federally or state-listed plant species is identified during botanical surveys, the project owner shall immediately notify the CPM, USFWS's Sacramento Fish and Wildlife Office, and CDFW's Central Regional Office.

At least 60 days prior to the start of any project-related ground disturbing activities or start of construction in a previously undisturbed area along a linear route, the project owner shall submit a letter report summarizing the results of focused botanical surveys, including GPS'ed locations of all identified occupied rare plant areas. The report shall include a GPS mapping of all occupied rare plant areas, ESA locations, and installed protective fencing. The report shall include the time, date, and duration of the survey;

identity and qualifications of the surveyor (s); and a list of plant and wildlife species observed and any other information included in CDFW's botanical field survey protocol (CDFG 2009).

No less than 30 days prior to the start of any ground-disturbing activities or start of construction in a previously undisturbed area along a linear route, the Designated Biologist shall establish Environmentally Sensitive Areas (ESAs) around all identified rare plant locations that occur outside but within 200 feet of project construction areas. No less than 10 days prior to the start of any project-related ground disturbing activities, the project owner shall submit grading plans and/or construction drawings to the CPM showing the locations of all special-status plant Environmentally Sensitive Areas and fenced areas.

REVEGETATION PLAN

BIO-18 The project owner shall prepare and implement a Revegetation Plan to restore construction areas that were subject to temporary disturbance, including equipment staging areas, buried pipeline routes primarily along the carbon dioxide pipeline, and other non-farmed areas along project linear routes. The objectives of the Revegetation Plan shall be to identify areas appropriate for revegetation activities, restore wildlife habitat values, stabilize disturbed soils, minimize erosion and sedimentation impacts to soil and water resources, prevent colonization by noxious weeds and other non-native plants, and salvage native plantings and seed from project construction areas for use in revegetation.

At a minimum, the Revegetation Plan shall include: a description of the project area habitat types to be temporarily impacted; discussion of revegetation methods and goals for revegetation which takes into consideration a phased construction schedule of linear routes; performance standards and timeline for meeting success criteria; methods for salvaging seeds of annual species, storing topsoil, and preserving germplasm for use in revegetation areas and/or use of locally collected seed; methods for controlling invasive weeds and weed management measures in revegetation areas; contingency parameters if success criteria are not met; and a long-term monitoring and reporting schedule during construction and operation.

Target performance standards at the end of each annual monitoring period shall be as follows:

a. total absolute cover of all plants shall equal at least 30 percent;

b. at least 60 percent of the perennial species observed within the restored areas (relative cover) shall be locally native species that naturally occur in allscale scrub habitat; and

c. Relative cover of non-native plants within the temporarily disturbed areas shall equal or not exceed the relative cover of non-native plants in the adjacent habitats.

Verification: These measures shall be incorporated into the BRMIMP as required under Condition of Certification **BIO-5** and reported in Monthly Compliance Reports.

At least 60 calendar days prior to the start of any project ground-disturbing activities, the project owner shall submit a draft Revegetation Plan to the CPM, CDFW, and USFWS for review and comment. At least 30 calendar days prior to the start of construction, the project owner shall submit a final Revegetation Plan that incorporates agency comments and input. The final plan shall be reviewed and approved by the CPM based on consultation with CDFW and USFWS. Any modifications to the final plan shall be made only after review and approval by the CPM, in consultation with CDFW and USFWS.

As part of the Annual Compliance Report to the CPM, each year following operationand in accordance with the monitoring and reporting schedule specified in the CPM-approved Revegetation Plan, the Designated Biologist shall provide a summary of the revegetation activities for the year, a discussion of whether revegetation performance standards were met for the year, and recommendations for remedial action for the upcoming year until performance standards are met.

MITIGATION FOR STATE WATERS

BIO-19 The project owner shall finalize and implement the following measures prior to the start of any project-related ground disturbance activities in order to avoid and minimize impacts to state jurisdictional waters:

1. Finalize and implement a Horizontal Directional Drilling (HDD) Plan inclusive of a frac-out plan following the Department of Water Resources (DWR) Encroachment Permit Guidelines and application and construction drawing requirements including, but not limited to details of each crossing location; type and dimensions of pipes, joints and sleeve casings; a description of drilling mud control measures; methods to control pipeline expansion and contraction; location of shutoff valves; and location of buried aqueduct communication control cables (URS 2012b, URS 2013d).

2. Implement Streambed Impact Avoidance and Minimization Measures. The following Best Management Practices (BMPs) shall be implemented during project construction and operation to minimize indirect impacts to ephemeral drainages and irrigation canals from HDD activities in the project area:

    a. Work Period. For any work proposed in ephemeral drainages along the carbon dioxide pipeline route, the time period for completing the work within the stream zone shall be restricted to periods of low stream flow and dry weather and shall be confined to the period of May 1 to October 1. Construction activities shall be timed with awareness of precipitation forecasts and likely increases in stream flow.

Construction activities within the stream zone shall cease until all reasonable erosion control measures, inside and outside of the stream zone, have been implemented prior to all storm events. Revegetation, restoration and erosion control work is not confined to this time period.

b. No equipment shall work in the water.

c. Spoil Placement. To prevent burying, trapping, or crushing of wildlife, spoil from project construction activities shall not be placed on or near the canal banks to avoid covering rodent burrows or bank-top soil crevices

d. Heavy Equipment Confined to Existing Roads. Construction activities that occur within upland wildlife habitat will be minimized. When possible, movement of heavy equipment shall be confined to existing roadways to minimize disturbance.

e. Cover Spoil Piles. The contractor shall have readily available plastic sheeting or visquine and will cover exposed spoil piles and exposed areas to prevent these areas from losing loose soil into the stream. These covering materials shall be applied when it is evident rainy conditions threaten to erode loose soils into the stream.

f. Equipment Over Drip Pans. Stationary equipment such as motors, pumps, generators, and welders, located within or adjacent to the stream/lake shall be positioned over drip pans.

g. Check Vehicles/Equipment Daily. Any equipment or vehicles driven and/or operated within or adjacent to the ephemeral drainage shall be checked and maintained daily to prevent leaks of materials that if introduced to water could be deleterious to aquatic habitat or wildlife.

h. Control Drilling Mud. In accordance with the CPM-approved Horizontal Directional Drilling (HDD) Plan for the project, at no time shall drill cuttings, drilling mud, and/or materials or water contaminated with bentonite or any other substance deemed deleterious to fish or wildlife be allowed to enter the stream or be placed where they may be washed into the stream. Any contaminated water/materials from the drilling and/or project activities shall be pumped or placed into a holding facility and removed for proper disposal.

i. Vegetation Removal. Disturbance or removal of vegetation shall not exceed the minimum necessary to complete operations. No native trees shall be removed or damaged without prior consultation and approval of the CPM. Using hand tools (clippers, chain saw, etc.), trees may be trimmed to the extent necessary to gain access to the work sites. All cleared material/vegetation shall be removed out of the riparian/stream zone.

j. Sediment Control. Precautions to minimize turbidity/siltation shall be taken into account during project planning and implementation. This may require the placement of silt fencing, coir logs, coir rolls, straw bale dikes, or other siltation barriers so that silt and/or other deleterious materials are not allowed to pass to downstream reaches. Passage of sediment beyond the sediment barrier(s) is prohibited. If any sediment barrier fails to retain sediment, corrective measures shall be taken. The sediment barrier(s) shall be maintained in good operating condition throughout the construction period and the following rainy season. Maintenance includes, but is not limited to, removal of accumulated silt and/or replacement of damaged silt fencing, coir logs, coir rolls, and/or straw bale dikes. Products with plastic monofilament or jute netting (such as found in straw wattles/fiber rolls and some erosion control blankets) shall not be allowed. Wildlife-friendly erosion control and sediment control products that will not entangle wildlife shall be used instead. The project owner is responsible for the removal of non-biodegradable silt barriers after the disturbed areas have been stabilized with erosion control vegetation (usually after the first growing season). Upon the Designated Biologist's determination that turbidity/siltation levels resulting from project-related activities constitute a threat to aquatic life, activities associated with the turbidity/siltation shall be halted until effective CPM-approved control devices are installed or abatement procedures are initiated.

Verification: These measures shall be incorporated into the BRMIMP as required under Condition of Certification **BIO-5** and reported in each Monthly Compliance Report during project construction.

The project owner shall notify the CPM and CDFW, in writing, at least five days prior to the initiation of any project-related HDD activities under any irrigation canals in the project areas or work in jurisdictional state waters.

COMPENSATORY HABITAT MITIGATION FOR UPLAND SPECIES

BIO-20 To compensate for project impacts to covered species (San Joaquin kit fox, giant kangaroo rat, San Joaquin antelope squirrel, Tipton's kangaroo rat, and Swainson's hawk), non-covered species (blunt-nosed leopard lizard, western burrowing owl) and their habitat as indicated in the above conditions of certification (**BIO-7**, **BIO-8**, **BIO-9**, **BIO-11**, **BIO-13, and BIO-14**), the project owner shall permanently protect and perpetually manage compensatory habitat for these species.

To meet this requirement, the project owner shall provide for both the permanent protection and management of CPM-approved Habitat Management (HM) lands that meet species habitat criteria for project impacts to 773 acres of habitat for San Joaquin kit fox; 192 acres of habitat each for giant kangaroo rat, San Joaquin antelope squirrel, Tipton's kangaroo rat, burrowing owl, and blunt-nosed leopard lizard; and 571 acres of impact for Swainson's hawk foraging habitat as described below. If all or a portion of the proposed HM lands meet habitat criteria for more than one covered or non-covered species listed above and meets the approval of the CPM, these habitat mitigation acreages may be nested.

1. Cost Estimates. The CPM, afterconsultation with CDFW and USFWS, will estimate the cost of acquisition, protection, and perpetual management of the HM lands as follows and as described in Section 2 below; these estimates are used to calculate the amount of security required under this Condition of Certification:

a. Land acquisition costs estimated using local fair market current value for lands with habitat values meeting mitigation requirements;

b. Start-up costs for HM lands, including initial site protection and enhancement costs;

c. Interim management period funding; and

d. Long-term management funding estimated initially for the purpose of providing Security to ensure implementation of HM lands management.

2. Habitat Acquisition and Protection. To provide for the acquisition and perpetual protection and management of the HM lands, the project owner shall:

a. Fee Title/Conservation Easement. Acquire and transfer fee title to the HM lands or a conservation easement to the HM lands to CDFW pursuant to terms approved in writing by the CPM. Alternatively, the CPM in consultation with CDFW and USFWS may authorize a governmental entity, special district, non-profit organization, for-profit entity, person, or another entity to hold title to and manage the property provided that the entity or person is eligible to hold the lands under California law, including but not limited toGovernment Code section 65967 and Civil Code section 815.3. If CDFW does not take fee title to the HM lands, the project owner shall convey a conservation easement in a form approved by the CPM to an entity approved by the CPM. If CDFW does not hold the conservation easement, the Energy Commission shall be expressly named in the conservation easement as a third-party beneficiary. The project owner shall obtain written approval from the CPM of the grantee and the terms of any conservation easement before its execution or recordation. Any instrument conveying interest in the HM lands shall include a provision consistent with Government Code section 65967, subdivision (e) that provides for reversion of the land to the State of California or another entity designated by the CPM if it is determined the land is not being held, monitored, or managed for conservation purposes;

b. HM Lands Approval. Obtain CPM written approval of the HM lands before any acquisition or transfer of the land by submitting, at least three months before any acquisition or transfer, a formal Lands for Acquisition Proposal identifying the land to be purchased or property interest conveyed to an approved entity as mitigation for the project's impacts on covered species and non-covered species;

c. HM Lands Documentation. Provide a recent preliminary title report, initial hazardous materials survey report, and other documents required by the CPM and other agencies for review of the proposed conveyance. All documents conveying the HM lands and all conditions of title are subject to the written approval of the CPM, and, if applicable, the Wildlife Conservation Board and the Department of General Services;

d. Land Manager. Designate both an interim and long-term land manager approved by the CPM. The interim and long-term land managers may, but need not, be the same. The interim and/or long-term land managers may be the landowner or another party. Documents related to land management shall identify both the interim and long-term land managers. Any replacement of the lands manager requires CPM approval prior to the change in land owner. The project owner shall provide written notification to the CPM, CDFW, and USFWS of any subsequent changes in the land manager. If CDFW will hold fee title to the mitigation land, CDFW will also act as both the interim and long-term land manager unless otherwise specified by the CPM.

e. Start-up Activities. Provide for the implementation of start-up activities, including the initial site protection and enhancement of HM lands, once the HM lands have been approved by the CPM. Start-up activities include, at a minimum: (1) preparing a final management plan for CPM approval following consultation with CDFW and USFWS approval (see http://www.wildlife.ca.gov/habcon/conplan/mitbank/); (2) conducting a baseline biological assessment and land survey report within three months of easement recording or transfer; (3) developing and transferring geographic information systems (GIS) data if applicable; (4) establishing initial fencing; (5) conducting litter removal; (6) conducting initial habitat restoration or enhancement, if applicable; and (7) installing signage;

f. Interim Management (Initial and Capital). Provide for the interim management of the HM lands. The project owner shall ensure that the interim land manager implements the interim management of the HM lands as described in the final management plan and conservation easement approved by the CPM. The interim management period shall be a minimum of three years from the date of HM land acquisition and protection and full funding of the endowment and shall include expected management following start-up activities. Interim management period activities described in the final management plan shall include fence repair, continuing trash removal, site monitoring, and vegetation and invasive species management, among other activities determined necessary following initial assessment and approval of the HM lands by the CPM. The project owner shall include a cost estimate for interim land management activities in the security amount, which will be maintained for the three-year interim period. Upon completion of the three-year interim period, the project owner shall promptly fund the land manager's performance of the interim land management tasks outlined in the approved land management plan.

g. Reimburse State Agencies. The project owner shall reimburse CDFW or the Energy Commission for all reasonable expenses incurred by CDFW or the Energy Commission such as transaction fees, account set-up fees, administrative fees, title and documentation review and related title transactions, expenses incurred from other state agency reviews, and overhead related to transfer of HM lands to CDFW.

3. Endowment Fund. The project owner shall ensure that the HM lands are perpetually managed, maintained, and monitored by the long-term land manager in accordance with the conservation easement and the final management plan approved by the CPM by establishing a long-term management fund (endowment). The endowment must be in an amount sufficient to fund the perpetual management, maintenance, monitoring, and other activities on the HM lands consistent with the final management plan. The endowment includes the money initially deposited by the project owner and all interest, dividends, other earnings, additions and appreciation to the account. The endowment shall be held and managed pursuant to Government Code sections 65965-65968, other applicable provisions of California law, and the requirements in this Condition of Certification.

   After the interim management period, the project owner shall ensure that the designated long-term land manager implements the management and monitoring of the HM lands in perpetuity to preserve the lands' conservation values consistent with the conservation easement and in accordance with the final management plan. Such activities shall be funded through the endowment.

a. Identify an Endowment Manager. The endowment shall be held by the endowment manager, which shall be an entity eligible to hold the endowment pursuant to Government Code sections 65965-65968 and approved in writing by the CPM. The project owner shall submit to the CPM, USFWS, and CDFW a written proposal for an endowment manager along with a copy of the proposed endowment manager's certification pursuant to Government Code section 65968(e). The CPM will notify the project owner in writing of its approval or disapproval of the proposed endowment manager;

b. Calculate the Endowment Funds Deposit. After obtaining CPM written approval of the HM lands, final long-term management plan, and endowment manager, the project owner shall prepare a property analysis record (PAR) [or PAR-equivalent analysis (hereinafter "PAR")] to calculate the amount of funding necessary to ensure the long-term management of the HM lands (endowment deposit amount). The project owner shall submit to the CPM for review and approval the results of the PAR before transferring funds to the endowment manager. The CPM will consult with USFWS and CDFW during its review of the PAR.

b.1. Capitalization Rate and Fees. The project owner shall obtain the capitalization rate from the selected endowment manager for use in calculating the PAR and adjust for any additional administrative, periodic, or annual fees.

b.2.Endowment Buffers/Assumptions. The project owner shall include in PAR assumptions the following buffers for endowment establishment and use that will substantially ensure long-term viability and security of the endowment:

b.2.1. Ten Percent Contingency. A 10 percent contingency shall be added to each endowment calculation to hedge against underestimation of the fund, unanticipated expenditures, inflation, or catastrophic events.

b.2.2. Three Years Delayed Spending. The endowment shall be established assuming spending will not occur for the first three years after full funding.

b. 2.3. Non-annualized Expenses. For all large capital expenses to occur periodically but not annually such as fence replacement or well replacement, payments shall be withheld from the annual disbursement until the year of anticipated need or upon request to endowment manager and the CPM.

c. Transfer Long-term Endowment Funds. The project owner shall transfer the long-term endowment funds to the endowment manager upon CPM approval of the endowment deposit amount identified above. The approved endowment manager may pool the endowment with other endowments for the operation, management, and protection of HM lands for local populations of the covered species and non-covered species for HECA but shall maintain separate accounting for each endowment. The endowment manager shall, at all times, hold and manage the endowment in compliance with Government Code sections 65965-65968 and other applicable laws.

4. Performance Security. The project owner may proceed with project activities only after the owner has ensured funding (security) to complete any activity that has not been completed before project activities begin is available. The project owner shall provide security as follows:

   a. Security Amount. The amount of the security shall be determined based on the cost estimates identified in Section 1.0 above.

   b. Security Form. The security shall be in the form of an irrevocable letter of credit approved in advance in writing by the CMP, or another form of security approved in advance in writing by the CPM.

   c. Security Holder. The security shall be held by the Energy Commission or in a manner approved in advance in writing by the CPM after consultation with USFWS and CDFW.

   d. Security Timeline. Written verification that the security has been established shall be provided to the CPM, USFWS, and CDFW at least 30 days prior to the start of any project-related ground disturbing activities.

   e. Security Drawing. The security shall allow the CPM to draw on the principal sum if the CPM, afterconsultation with CDFW, determines that the project owner has failed to comply with the secured obligations in this Condition of Certification within the time period provided in this condition.

   f. Security Release. The security (or any portion of the security then remaining) shall be released to the project owner after the CPM has conducted an on-site inspection and received confirmation that all secured requirements have been satisfied. Confirmation shall include appropriate documentation including, but not limited to:

   - Written documentation of the acquisition of the HM lands;
   - Copies of all executed and recorded conservation easements;
   - Written confirmation from the approved endowment manager of its receipt of the full endowment deposit amount;
   - Timely submission of all required reports due prior to the release of security; and
   - Completion of start-up activities and interim management activities.

To the extent the security provided by the project owner allows partial release of the security, the CPM may authorize proportional reduction in security after completion of significant milestones, such as acquisition of approved HM lands. This condition of certification has been developed based on the listed species impact acreages specified in this condition. If following construction and the final accounting of the acreages of vegetation communities/cover types disturbed, it is determined that the project-related ground disturbance to listed species habitat exceeds these amounts, the project owner shall petition the Energy Commission for an amendment.

<u>Verification:</u> If the acquisition of HM lands required under this condition and all other activites listed in Item 1 of this Condition of Certification will not be completed prior to the start of ground-disturbing activities, the project owner shall provide written verification to the CPM, CDFW, and USFWS that the security has been established at least 30 days prior to the start of any project-related ground disturbing activities. Even if security is provided, the project owner or an approved third party must complete the required acquisition, protection, transfer of all HM lands, record any required deeds, and fund the endowment no later than 18 months from the start of project-related ground disturbing activities.

At least three months before easement recording and title transfer of the HM lands, the project owner shall submit a Formal Lands for Acquisition Proposal describing the parcels intended for purchase, including a conservation easement, baseline biological assessment, preliminary title report, land survey report and other required documents for review and approval by the CPM after consultation with CDFW and USFWS. HM lands must be approved by the CPM in writing prior to acquisition, easement recording, or title transfer.

No later than two months after the project owner transfers fee title on HM land and records the conservation easement, as determined by the date on the title, the project owner, or an approved third party, shall provide a copy of the HM land management plan for the compensation lands to the CPM for review and approval after consultation with CDFW and USFWS. The land management plan shall identify but is not limited to discussing the following: start-up habitat improvement activities, interim, and long-term management activites of the compensation lands. The land management plan shall also identify the land manager. In the case of a change in land manager of the HM lands, the project owner shall submit the change request to the CPM for approval at least 30 days prior.

The project owner shall complete and submit to the CPM, CDFW, and USFWS a PAR or PAR-like analysis no later than two months after the CPM approves the HM land management plan. The project owner must obtain approval of the PAR analysis from the CPM, after consultations with CDFW and USFWS. As determined by the approved PAR, the project owner shall fully fund the required amount for long-term maintenance and management of the HM lands by establishing a long-term management fund (endowment), no later than 30 days after the CPM approves the PAR or PAR-like analysis. Written verification shall be provided to the CPM, USFWS, and CDFW to confirm payment of the long-term maintenance and management funds.

No later than two months after the approved land management plan identifies what activities are required to provide for initial protection and habitat improvement on the compensation lands, the project owner shall pay land manager's invoices for those approved activities and provide written verification to the CPM, CDFW, and USFWS of what funds are available and how costs will be paid.

Wtihin 90 days after completion of project construction and to verify that the extent of construction disturbance does not exceed that described in this analysis, the project owner shall submit a GIS analysis using aerial photographs, at an approved scale, taken before and after construction to the CPM. The first set of aerial photographs shall reflect site conditions <u>prior</u> to any preconstruction site mobilization and construction-related ground disturbance, grading, boring, and trenching, and shall be submitted prior to initiation of such activities. The second set of aerial photographs shall be taken <u>subsequent</u> to completion of construction, and shall be submitted to the CPM no later than 90 days after completion of construction. The project owner shall also provide a final accounting of the acreages of vegetation communities/cover types present before and after construction in the construction termination report.

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Biological Resources

Appendix BIO-1: Biological Assessment

NATIONAL ENERGY TECHNOLOGY LABORATORY
Albany, OR • Morgantown, WV • Pittsburgh, PA

U.S. DEPARTMENT OF ENERGY

March 1, 2013

Thomas Leeman
Chief, San Joaquin Valley Division
U.S. Fish and Wildlife Service
2800 Cottage Way, Room W-2605
Sacramento, CA 95825-1846

Dear Mr. Leeman:

The U. S. Department of Energy (DOE) is proposing to provide financial assistance to construct the Hydrogen Energy California (HECA) Integrated Gasification Combined-Cycle Polygeneration Project in western Kern County, California. The enclosed biological assessment (BA) evaluates potential effects to endangered and threatened species and designated critical habitats associated with the construction and operation of the HECA Project and the related Occidental of Elk Hills, Inc. (OEHI) Project (the proposed action). A detailed description of the proposed action and the area that would be affected by the proposed action is provided in the BA.

Formal consultation was originally initiated on February 4, 2010 with the transmittal of the draft BA. The enclosed version of the BA has been revised to address comments provided by the USFWS on August 6, 2010 and subsequent project modifications.

Although the DOE is not providing financial assistance to OEHI in connection with the OEHI Project, this BA evaluates the potential effects associated with the OEHI Project during the demonstration period as reasonably foreseeable indirect effects of the proposed agency action.

As described in the enclosed BA (*2 copies*), the proposed action may affect and is likely to adversely affect, the following species that are listed under the Endangered Species Act (ESA):

- Blunt-nosed leopard lizard;
- Giant kangaroo rat;
- Tipton kangaroo rat; and
- San Joaquin kit fox.

However, the proposed action may affect, but is not likely to adversely affect, the following species that is listed as endangered under the federal ESA:

- Buena Vista Lake shrew.

There is no designated critical habitat in the action area, and the proposed action would not affect the designated critical habitat.

3610 Collins Ferry Road, P.O. Box 880, Morgantown, WV 26507
fred.pozzuto@netl.doe.gov • Voice (304) 285-5219 • Fax (304) 285-4403 • www.netl.doe.gov

The current condition and locations of the affected species are described in the BA. Potential effects would include temporary and permanent loss of habitats potentially utilized by blunt-nosed leopard lizard, giant kangaroo rat, Tipton kangaroo rat, and San Joaquin kit fox associated with the proposed action. The construction, operation, and decommissioning of the HECA Project and the OEHI Project will also disturb, and in some limited instances, result in mortality of individuals. Avoidance and minimization measures are proposed or already exist that would reduce potential take of federally listed species and provide long-term beneficial effects. These measures would avoid or minimize the potential for mortality, disturbance, and habitat degradation, as well as, other potential adverse effects on federally listed species. Additional conservation measures would restore and provide permanent protection and enhancement of habitats for federally listed species in the action area. Collectively, when implemented, these measures would avoid jeopardy of the affected species, and improve opportunities for recovery of the species.

DOE requests initiation of formal consultation under Section 7(a)(2) of the ESA. We look forward to working with you towards the successful resolution of this process. Please contact me at (304) 285-5219, or contact HECA's biological consultant, Steve Leach, at (510) 874-3205 regarding this consultation request.

Sincerely,

Fred E. Pozzuto
NEPA Compliance Officer

Enclosure

CEC - Mr. B. Worl

cc w\o enclosure:

URS - Mr. S. Leach
SCS Energy - Ms. M. Mascaro

HYDROGEN ENERGY CALIFORNIA
KERN COUNTY, CALIFORNIA

BIOLOGICAL ASSESSMENT

Prepared for:

U.S. Department of Energy
Environmental Compliance Division
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URS Project Number 28068052

February 2013

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List of Acronyms

AB	Assembly Bill
ADT	average daily traffic
AFC	Application for Certification
APLIC	Avian Power Line Interaction Committee
APN	Assessor's Parcel Number
BA	Biological Assessment
bgs	below ground surface
BRMIMP	Biological Resource Mitigation Implementation and Monitoring Plan
BVWSD	Buena Vista Water Storage District
CCPI	Clean Coal Power Initiative Round 3
CD	compact disc
CDFG	California Department of Fish and Game
CEC	California Energy Commission
CNDDB	California Natural Diversity Database
CNPS	California Native Plant Society
CO_2	carbon dioxide
CRP	CO_2 Recovery Plant
CTB	Central Tank Battery
DOE	U.S. Department of Energy
EHOF	Elk Hills Oil Field
EOR	enhanced oil recovery
ESA	Endangered Species Act
GIS	Geographic Information System
HCP	Habitat Conservation Plan
HDD	Horizontal directional drilling
HECA	Hydrogen Energy California
I-5	Interstate 5
KRFCC	Kern River Flood Control Channel
MOU	Memorandum of Understanding
NEPA	National Environmental Policy Act
NMFS	National Marine Fisheries Service
OEHI	Occidental of Elk Hills, Incorporated
petcoke	petroleum coke
PG&E	Pacific Gas and Electric Company
Project	HECA power generating facility
RCF	Reinjection Compression Facility
ROW	right-of-way
SR	State Route
syngas	synthesis gas
USC	U.S. Code
URS	URS Corporation
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
WKWD	West Kern Water District

EXECUTIVE SUMMARY

Hydrogen Energy California LLC (HECA LLC) is proposing an Integrated Gasification Combined-Cycle polygeneration project (hereafter referred to as the HECA Project). HECA LLC is owned by SCS Energy California LLC. The HECA Project will gasify a 75 percent coal and 25 percent petroleum coke fuel blend to produce synthesis gas (syngas). Syngas produced via gasification will be purified to hydrogen-rich fuel, which will be used to generate low-carbon baseload electricity in a Combined-Cycle Power Block; low-carbon nitrogen-based fertilizer in an integrated Manufacturing Complex; and carbon dioxide (CO_2) for use in enhanced oil recovery (EOR).

The fertilizer and power produced by the HECA Project have a low-carbon footprint, because more than 90 percent of the CO_2 in the syngas is captured and approximately 3 million tons per year of CO_2 is transported via pipeline for use in EOR, which results in simultaneous sequestration (storage) of the CO_2 in a secure geologic formation (HECA, 2012). CO_2 will be transported for use in EOR in the adjacent Elk Hills Oil Field, which is owned and operated by Occidental of Elk Hills, Inc. (OEHI) (hereafter referred to as the OEHI Project). This Biological Assessment (BA) covers both the HECA Project and the OEHI Project during the period of the U.S. Department of Energy (DOE) Demonstration Period, which is explained below.

The DOE is providing financial assistance to the HECA Project under the Clean Coal Power Initiative Round 3 (CCPI) via a cost-sharing agreement with HECA LLC covering project construction and a "Demonstration Period" for the first 2 years of project operations. The DOE's financial assistance for the construction and operation of the HECA Project during the Demonstration Period is referred to herein as the proposed Agency Action. The DOE will analyze potential environmental impacts associated with the proposed Agency Action by preparing an Environmental Impact Statement pursuant to the National Environmental Policy Act (NEPA). The DOE and the California Energy Commission plan to prepare a joint Environmental Impact Statement/Environmental Impact Report equivalent to satisfy both the requirements of NEPA and the California Environmental Quality Act.

Pursuant to the federal Endangered Species Act (ESA), DOE must ensure that "any action authorized, funded, or carried out…is not likely to jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of habitat. . ." 16 U.S. Code § 1536[a][2]. Although the DOE would not have any regulatory authority over the HECA Project or the OEHI Project, the funding associated with the proposed Agency Action triggers the need for DOE to consult with the U.S. Fish and Wildlife Service pursuant to Section 7 of the ESA regarding potential effects of the proposed Agency Action on endangered or threatened species.

Accordingly, this BA has been prepared to facilitate the Section 7 consultation process. The scope of this BA covers potential effects to endangered and threatened species associated with the construction and operation of the HECA Project and the OEHI Project. Operational effects are evaluated for the 25-year life of the HECA Project, and during the Demonstration Period for the OEHI Project. Although the DOE is not providing financial assistance to OEHI in connection with the OEHI Project, this BA evaluates the potential effects associated with the OEHI Project during the Demonstration Period as reasonably foreseeable indirect effects of the proposed Agency Action.

Construction, operation, and decommissioning of the HECA Project and the OEHI Project, including associated linears (pipelines, rail spurs, transmission lines, etc.) are likely to adversely affect the following federally listed species:

- Blunt-nosed leopard lizard;
- Giant kangaroo rat;
- Tipton kangaroo rat; and
- San Joaquin kit fox.

The proposed action may affect but is not likely to adversely affect the following species that is listed as endangered under the federal ESA:

- Buena Vista Lake shrew.

These determinations are based on temporary and permanent loss, associated with the proposed action, of habitats potentially used by blunt-nosed leopard lizard, giant kangaroo rat, Tipton kangaroo rat, and San Joaquin kit fox. Construction, operation, and decommissioning of the HECA Project and the OEHI Project will also disturb—and in some limited instances, result in—mortality of individuals. Avoidance and minimization measures are proposed, or already exist, that would reduce potential take of federally listed species and provide long-term beneficial effects. These measures include actions that would avoid or minimize the potential for mortality, disturbance, habitat degradation, and other potential adverse effects on federally listed species. Additional conservation measures would restore and provide permanent protection and enhancement of habitats for federally listed species in the Action Area (defined below). Collectively, when implemented, these measures would avoid jeopardy of the affected species, and improve opportunities for recovery of the species.

1.0 INTRODUCTION

Hydrogen Energy California LLC (HECA LLC) is proposing an Integrated Gasification Combined-Cycle polygeneration project (hereafter referred to as the HECA Project). HECA LLC is owned by SCS Energy California LLC. The HECA Project will gasify a 75 percent coal and 25 percent petroleum coke (petcoke) fuel blend to produce synthesis gas (syngas). Syngas produced via gasification will be purified to hydrogen-rich fuel, which will be used to generate low-carbon baseload electricity in a Combined-Cycle Power Block, low-carbon nitrogen-based fertilizers in an integrated Manufacturing Complex, and carbon dioxide (CO_2) for use in enhanced oil recovery (EOR).

The fertilizers and power produced by the HECA Project have a low-carbon footprint because more than 90 percent of the CO_2 in the syngas is captured and approximately 3 million tons per year of CO_2 is transported via pipeline for use in EOR, which results in simultaneous sequestration (storage) of the CO_2 in a secure geologic formation (HECA, 2012). CO_2 will be transported (via a ±3.4-mile pipeline) for use in EOR in the adjacent Elk Hills Oil Field (EHOF), which is owned and operated by Occidental of Elk Hills, Inc. (OEHI) (hereafter referred to as the OEHI Project). This Biological Assessment (BA) covers both the HECA Project and the OEHI Project during the period of the U.S. Department of Energy (DOE) Demonstration Period, as explained below.

The 453-acre HECA Project Site is approximately 7 miles west of the city of Bakersfield, and approximately 2 miles northwest of the unincorporated community of Tupman in western Kern County, California (Figure 1, Project Location). The HECA Project Site is adjacent to the EHOF (Figure 2, Project Vicinity). HECA has an agreement to purchase the HECA Project Site, as well as an additional 653 acres adjacent to the HECA Project Site, herein referred to as the Controlled Area (Figure 3, Project Site Map). The HECA Project Site and Controlled Area are currently used for farming purposes, including the cultivation of cotton, alfalfa, and onions.

OEHI is proposing to extend the life of the EOR operations at its Elk Hills Unit by using CO_2 to facilitate oil production. A pipeline will be constructed to transport CO_2 from the HECA Project Site to the OEHI Project Site; it will temporarily disturb approximately 28.89 acres and permanently impact approximately 0.11 acre. In addition, the OEHI Project will include construction of a 60.61-acre CO_2 EOR processing facility; and three additional 1.06-acre Satellite Gathering Stations for CO_2 EOR and sequestration. The OEHI Project will also use existing producing and injection wells.

The DOE has proposed providing financial assistance to the HECA Project under the Clean Coal Power Initiative Round 3 (CCPI) via a cost-sharing agreement with HECA LLC, covering project construction and a "Demonstration Period" for the first 2 years of project operations.[1] The DOE's proposed financial assistance for the construction and 25-year operation of the HECA Project, as well as the construction and operation of the OEHI Project during the Demonstration Period, is referred to herein as the proposed Agency Action. The DOE will analyze potential environmental impacts associated with the proposed Agency Action by preparing an Environmental Impact Statement pursuant to the National Environmental Policy Act (NEPA).[2] The DOE and the California Energy Commission (CEC) plan to prepare a joint Environmental Impact Statement/Environmental Impact Report equivalent to satisfy both the requirements of NEPA and the California Environmental Quality Act.[3]

Pursuant to the federal Endangered Species Act (ESA), DOE must ensure that "any action authorized, funded, or carried out...is not likely to jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of habitat. . ."[4] Although the DOE would not have any regulatory authority over the HECA Project or the OEHI Project, the funding associated with the proposed Agency Action triggers the need for DOE to consult with the U.S. Fish and Wildlife Service (USFWS) pursuant to Section 7 of the ESA, regarding potential effects of the proposed Agency Action on endangered or threatened species.

Accordingly, this BA has been prepared to facilitate the Section 7 consultation process. The scope of this BA covers potential effects to endangered and threatened species associated with the construction and operation of the HECA Project. Operational effects are evaluated for the

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[1] *See* DOE website, Clean Coal Power Initiative Round 3 ("On July 1, 2009, U.S. Department of Energy Secretary Steven Chu announced that projects by Basin Electric Power Cooperative and Hydrogen Energy International HECA LLC had been selected for up to $408 million in funding from the American Recovery and Reinvestment Act.") http://www.fossil.energy.gov/recovery/projects/ccpi.html. The DOE and HECA LLC entered into a Cooperative Agreement effective September 30, 2009. Under this agreement, the DOE has awarded up to $408 million in government sharing of the HECA Project costs associated with project construction and the Demonstration Period. Total HECA Project costs are estimated to be $4 billion; however, more detailed estimates are currently being prepared. *See* DOE website, DOE Signs Cooperative Agreement for New Hydrogen Power Plant, November 6, 2009, http://www.fossil.energy.gov/news/techlines/2009/09077-DOE_Signs_Cooperative_Agreement.html. The DOE financial assistance under the CCPI program relates to project construction and the Demonstration Period defined by a Cooperative Agreement between HECA LLC and the DOE.

[2] *See* DOE, Amended Notice of Intent Modifying the Scope of the Environmental Impact Statement for the Hydrogen Energy California's Integrated Gasification Combined Cycle Project, Kern County, CA, 77 Fed. Reg. 36519 (June 19, 2012).

[3] *See* 77 Fed. Reg. 36519, 36520.

[4] 16 USC § 1536[a][2]. Under the ESA, "[a]ction" is defined as "all activities or programs of any kind authorized, funded, or carried out, in whole or in part, by federal agencies" (50 Code of Federal Regulations § 402.02). The "effects of the action" are defined as "direct and indirect effects of an action ... together with the effects of other activities that are interrelated or interdependent with that action" (50 CFR § 402.02). "Interrelated actions" are, in turn, defined by the Services' regulations as "those that are part of a larger action and depend on the larger action for their justification." Interdependent action is defined as "those that have no independent utility apart from the action under consideration" (50 CFR § 402.02). Indirect effects as "those that are caused by the proposed action and are later in time, but still are reasonably certain to occur" (50 CFR § 402.02).

25-year operation of the HECA Project, and for the OEHI Project during the Demonstration Period. Although DOE is not providing financial assistance to OEHI in connection with the OEHI Project, this BA evaluates the potential effects associated with the OEHI Project during the Demonstration Period as reasonably foreseeable indirect effects of the proposed Agency Action.

The EHOF has already been the subject of Section 7 consultation. The EHOF is currently being operated in compliance with a 1995 Biological Opinion (Appendix A) issued by the USFWS, and a related 1997 Memorandum of Understanding (MOU) between OEHI and the California Department of Fish and Game (CDFG) (Appendix B) that has twice been updated, and remains in effect until 2014 (CDFG, 1997; 1999; 2010). The earlier Section 7 consultation was undertaken in connection with the Supplemental Environmental Impact Statement/Program Environmental Impact Report for the federal government's divestment of the EHOF, and that document contemplated CO_2 EOR and associated impacts. Compliance with the 1995 USFWS Biological Opinion and the 1997 CDFG MOU has been documented in annual and semi-annual monitoring reports submitted to USFWS since 1998.

OEHI reinitiated consultations with USFWS and CDFG in 2002 to support a multi-decade Habitat Conservation Plan (HCP) for the EHOF, and anticipates the new HCP being approved by the end of 2013. The new HCP is being negotiated in contemplation of continued operations consistent with the Supplemental Environmental Impact Statement/Program Environmental Impact Report for the federal government's divestment of the EHOF. OEHI reinitiated consultations with USFWS and CDFG to support a 50-year HCP for all production operations at the field, and anticipates that the Biological Opinion and MOU will be replaced by new Section 10 and Section 2081 permits supported by the HCP at some point in the future. However, until that occurs, the Biological Opinion remains in effect indefinitely, and the MOU remains in effect until December 31, 2014.

1.1 PROJECT PURPOSE AND NEED

The DOE proposed Agency Action is to provide limited financial assistance for the development, construction, and demonstration of the HECA Project. DOE has selected the HECA Project through a competitive process under the CCPI program. The Purpose and Need for DOE's proposed Agency Action are to advance the CCPI program by funding projects that have the best chance of achieving the program's objective as established by Congress—the commercialization of clean coal technologies that advance efficiency, environmental performance, and cost competitiveness well beyond the level of technologies that are currently in commercial service. The proposed HECA Project was selected under the CCPI program as one in a portfolio of projects that would represent the most appropriate mix to achieve programmatic objectives and meet legislative requirements.

The HECA Project will be a state-of-the-art facility that will produce electricity and other useful products for California with dramatically lower carbon emissions compared to traditional facilities.

The HECA Project is needed to provide dependable, low-carbon electricity to help meet future power needs, and to help "back up" intermittent renewable power sources, such as wind and solar, to support a reliable power grid. The HECA Project is also needed to provide low-carbon nitrogen-based fertilizers.

According to DOE:

> *The project will be among the cleanest of any commercial solid fuel power plant built or under construction and will significantly exceed the emission reduction targets for 2020 established under the Energy Policy Act of 2005. In addition, emissions from the project plant will be well below the California regulation requiring baseload plants to emit less greenhouse gases than comparably-sized natural gas combined cycle power plants (U.S. Department of Energy, HECA Project Facts, November 2011).*

In addition to DOE's directive to meet emission reduction targets by 2020, California Assembly Bill 32 (AB 32) also has a directive to reduce greenhouse gas emissions to 1990 levels by 2020. AB 32 requires the California Air Resources Board to assign emissions targets to each sector in the California economy, and to develop regulatory and market methods to ensure compliance. These government actions reinforce the timeliness of the HECA Project.

The HECA Project will achieve these important environmental objectives by capturing carbon from its processes and transporting the CO_2 for use in EOR, resulting in permanent sequestration (storage) in secure geologic formations within the earth. A key factor in the siting of the HECA Project is its proximity to EHOF. The EHOF offers an opportunity to beneficially use the CO_2 for EOR. In addition, because of the extensive and long-standing operations at the EHOF, much is known about the subsurface geology, which verifies that it is an ideal location for sequestration. Finally, locating the HECA Project adjacent to the EHOF minimizes the distance the CO_2 must be transported. The proposed Project Site is also close to existing power transmission and natural gas infrastructure, as well as a viable cooling water supply, all of which minimizes the cost and impacts of associated water and natural gas pipelines and electric transmission lines.

DOE recognizes HECA's importance in advancing carbon capture and sequestration:

> *A need exists to further develop carbon management technologies that capture and store or beneficially reuse carbon dioxide (CO_2) that would otherwise be emitted into the atmosphere from coal-based electric power generating facilities. Carbon capture and storage (CCS) technologies offer great potential for reducing CO_2 emissions and mitigating global climate change, while minimizing the economic impacts of the solution. Once demonstrated, the technologies can be readily considered in the commercial market-place by the electric power industry (U.S. Department of Energy, HECA Project Facts, November 2011).*

The HECA Project will provide numerous local, state, regional, national, and global benefits, including the following:

- Promoting energy security by converting abundant and inexpensive solid fuels—petcoke and coal—to clean hydrogen fuel to produce electricity and other useful products.
- Advancing a hydrogen-based transportation system in California by increasing the supply of available hydrogen.
- Improving the reliability of California's electrical grid by generating a nominal 300 megawatts of new, low-carbon baseload electricity—enough electricity to power over 160,000 homes.
- Supporting California's agricultural industries by producing over 1 million tons per year of low-carbon fertilizer.
- Reducing greenhouse gas emissions by capturing approximately 3 million tons of CO_2 per year—equivalent to eliminating 650,000 automobiles from the road—and transporting it for use in EOR, resulting in permanent sequestration.
- Demonstrating the commercial viability of carbon capture and sequestration as a viable method for reducing the carbon footprint of power generation and manufacturing.
- Promoting energy independence by increasing California's production of oil through EOR, extracting an otherwise unrecoverable 5 million barrels of oil each year.
- Improving local groundwater quality and agricultural production by extracting, treating, and using degraded groundwater.
- Providing local jobs to an estimated 2,500 construction workers at peak construction, and to 200 fulltime employees during Project operations.
- Boosting the local and California economy through direct investment and the resulting economic activity and tax revenues in the billions of dollars.

1.2 PURPOSE OF THE BIOLOGICAL ASSESSMENT

This BA documents potential effects of the HECA Project and the OEHI Project on federally listed threatened and endangered species within the Action Area. In addition to construction effects of the proposed facilities, this BA evaluates potential effects during the 25-year operational life of the HECA Project and the 2-year Demonstration Period of the OEHI Project. The Action Area is defined in this BA as the 453-acre HECA Project Site, the 4-acre Pacific Gas and Electric Company (PG&E) switching station, the 1.15–acre water wells, the 93-acre OEHI Project Site, and the construction footprints of the associated linear facilities and adjacent areas that could be directly or indirectly affected by the proposed action (50 Code of Federal Regulations §402.02). Consistent with CEC guidelines and the federal ESA regulations, the Action Area evaluated in this BA is a 1-mile area around the HECA Project Site, a 1,000-foot area adjacent to all associated linear facilities including the CO_2 pipeline, and the OEHI Project

Site. This BA was prepared in accordance with Section 7 of the ESA (16 U.S. Code [USC] 1536 [c]), and follows the standards established in DOE NEPA guidelines.

This BA is organized into eight sections based on the USFWS recommended outline (2008). Section 1 introduces the HECA Project and OEHI Project, HECA Project benefits, as well as the purpose and need for the proposed HECA Project, as detailed above in Section 1.1. Section 2 describes the HECA Project and OEHI Project in more detail. Section 3 describes the environmental setting, including the vegetation communities within the Action Area. Section 4 describes the study methods used to identify the federally listed species that may be affected by the HECA Project and OEHI Project, and describes the life history of these species. Section 5 evaluates the potential adverse effects to these species and associated habitats. Section 6 summarizes the effects to these species and habitat, and includes an effects determination for each species. References are listed in Section 7, and the list of preparers for this BA is provided in Section 8.

The scope of this document is for use by the DOE to support consultation with the USFWS under the ESA. Potential effects on federally listed species are evaluated in accordance with Section 7 of the ESA (16 USC 1536). Criteria used to determine which species were considered for this BA and potential adverse effects to those species from HECA Project and OEHI Project activities are presented in Section 4. In addition, this BA proposes conservation measures to avoid and/or minimize mortality or disturbance to potentially affected species (Section 2).

1.3 SPECIES CONSIDERED IN THIS BIOLOGICAL ASSESSMENT

Federally listed species occurrences and associated habitats in the Action Area are identified based on the results of a literature review, comprehensive background search, and field surveys. A search of four U.S. Geological Survey (USGS) quadrangles in the HECA Project area was conducted (Appendix C); this list was reduced based on habitat and known ranges. The eight species listed as federally endangered or threatened that have the potential to occur within the Action Area are listed in Table 1 (on the following page). These federally listed species are discussed in Sections 4, 5, and 6, and are the subject of this BA. There is no designated Critical Habitat in the Action Area or the vicinity.

1.4 HISTORY OF CONSULTATION

HECA and the DOE have coordinated with the USFWS regarding the HECA Project since 2008. Consultation has included informal discussion, site visits, and formal submittals. A detailed chronology of coordination with the USFWS regarding the HECA Project and the federal Section 7 consultation process is presented below. It should be noted that the original BP/Rio Tinto Project was located in a more sensitive area; any correspondence prior to September 2010 may discuss site conditions and/or impacts that no longer apply, because the project now is being proposed in a different location.

- April 22, 2008, electronic mail from David Kisner (URS Corporation [URS]) to Susan Jones (USFWS) and James Diven (URS) regarding biological aspects in the vicinity of the Project. This discussion related to the former HECA Project Site located in Elk Hills.

Table 1
Federally Listed Species with Potential to Occur within the Action Area

Common Name	Scientific Name	Federal Status
Plants		
California jewel-flower	*Caulanthus californicus*	Endangered
Kern mallow	*Eremalche kernensis*	Endangered
San Joaquin woollythreads	*Monolopia congdonii*	Endangered
Reptiles		
Blunt-nosed leopard lizard	*Gambelia sila*	Endangered
Mammals		
Buena Vista lake shrew	*Sorex ornatus relictus*	Endangered
Giant kangaroo rat	*Dipodomys ingens*	Endangered
Tipton kangaroo rat	*Dipodomys nitratoides nitratoides*	Endangered
San Joaquin kit fox	*Vulpes macrotis mutica*	Endangered

- July 10, 2008, meeting at California CDFG Office in Fresno, California with Julie Vance (CDFG), Susan Jones (USFWS; by telephone), and Peter Cross (USFWS; by telephone). This discussion again involved the former HECA Project Site located in Elk Hills.
- October 14, 2008, Project meeting at CDFG Office in Fresno, California with Julie Vance (CDFG), Susan Jones (USFWS; by telephone), and Peter Cross (USFWS; by telephone). This discussion again involved the former HECA Project Site located in Elk Hills.
- January 29, 2009, phone conversation between Tim Kuhn (USFWS) and David Kisner (URS) regarding BA/Biological Opinion and conservation measures for the current HECA Project Site.
- June 6, 2009, site visit with Tim Kuhn (USFWS) and Julie Vance (CDFG) to review HECA Project linears and biological constraints.
- February 4, 2010, letter from R. Paul Detwiler (DOE) to Tim Kuhn (USFWS), requesting initiation of formal Section 7 consultation for the *Hydrogen Energy International Integrated Gasification Combined Cycle and Carbon Capture and Sequestration Project.*
- February 5, 2010, electronic mail and attached BA transmitted from Dale Shileikis (URS) to Tim Kuhn and Paul Detwiler on behalf of HECA.
- March 30, 2010, phone conversation between Tim Kuhn (USFWS) and David Kisner (URS) regarding BA/Biological Opinion, rare plants, Migratory Bird Treaty Act, and Coles Levee Ecological Reserve.

- April 12, 2010, CEC Data Response and Issue Resolution Workshop in Tupman, California. Public meeting with CEC (Amy Golden), USFWS (Tim Kuhn), and CDFG (Julie Vance) to discuss biological aspects of the proposed HECA Project.
- June 9, 2010, email correspondence from USFWS biologist Tim Kuhn to CEC and CDFG regarding comments on the February 5, 2010 BA for the HECA Project.
- August 6, 2010, comment letter from USFWS biologist Tim Kuhn regarding the February 8, 2010 BA for the HECA Project.
- September 15, 2010, phone conversation between Tim Kuhn (USFWS) and David Kisner (URS) regarding comments on BA, *California Aqueduct Habitat Conservation Plan*, and San Joaquin Kit Fox Recovery Area Geographic Information System (GIS) data layer.
- September 23, 2010, electronic mail transmittal from Tim Kuhn (USFWS) to David Kisner (URS) of San Joaquin Kit Fox Recovery Area GIS layer and *Draft California Aqueduct San Joaquin Field Division Habitat Conservation Plan.*
- November 2, 2010, meeting with Tim Kuhn (USFWS), U.S. Environmental Protection Agency Region IX, DOE, HECA, and URS regarding ESA consultation for the HECA Project.
- January 18, 2012, meeting with Bill Pelle, Thomas Leeman, and Dan Russell from USFWS to discuss Section 7 consultation for the HECA Project. The meeting was organized by DOE to provide an overview of the new HECA Project components for USFWS and review the potential ESA issues. Other attendees included R. Paul Detwiler (DOE), Marisa Mascaro (HECA), George Landman (HECA) and Steve Leach (URS).
- February 6, 2012, meeting at CDFG office in Fresno, California with Julie Vance (CDFG), and Annee Ferranti (CDFG). This discussion involved introducing the new project team and identifying new project components; the new project elements were discussed with regard to the known and potential biological resources in the area.
- October 17, 2012, field meeting with Thomas Leeman from USFWS to discuss Section 7 consultation for the HECA Project. The meeting included a field review of the HECA Project components for USFWS and CDFG and discussion of the potential ESA issues. Other attendees included Julie Vance (CDFG), Amy Golden (CEC), George Landman (HECA), Ed Western (HECA), Jan Novak (URS), David Kisner (URS), and Steve Leach (URS).

2.0 PROJECT DESCRIPTION

The 453-acre HECA Project Site is currently used for active agricultural purposes, including cultivation of cotton, alfalfa, and onions. HECA also has the option to purchase 653 acres adjacent to the HECA Project Site, over which HECA will control access and future land uses. The HECA Project will generate a nominal 300-megawatt output of low-carbon baseload electrical power. The HECA Project will capture more than 90 percent of the CO_2 in the production of the hydrogen fuel, and transport (via pipeline) approximately 3 million tons per year of CO_2 to the EHOF for EOR and sequestration. In addition, the HECA Project will use the hydrogen produced in the gasifier to produce low-carbon nitrogen-based fertilizer in an integrated Manufacturing Complex.

In addition to the Project Site, the HECA Project includes construction and operation of five linear facilities, which include (1) an approximately 2-mile-long electrical transmission line to a new PG&E switching station; (2) an approximately 13-mile-long natural gas interconnection with an existing PG&E natural gas pipeline; (3) an approximately 15-mile-long process water supply pipeline from the Buena Vista Water Storage District (BVWSD); (4) an approximately 1-mile-long potable water supply pipeline from West Kern Water District; and (5) an approximately 5-mile-long industrial railroad spur that will connect to the San Joaquin Valley Rail Road.

The OEHI Project will include construction and operation of three primary EOR components, including (1) an approximately 3.4-mile-long CO_2 Pipeline from HECA to the Elk Hills Oil Field; (2) a CO_2 EOR Processing Facility at the southern terminus of the CO_2 Pipeline; and (3) three Satellite Gathering Stations.

Construction activities associated with each of the HECA and OEHI project components, including avoidance, minimization, and conservation measures, are described below, followed by descriptions of operation and maintenance of the facilities and the project schedule.

2.1 CONSTRUCTION ACTIVITIES

This section describes the construction activities associated with the proposed action. The activities are organized by location.

2.1.1 Power Generating Facility

The 453-acre HECA Project Site is intensively cultivated for the production of alfalfa, cotton, and onions, and has little habitat value for native flora and fauna. In addition, the closest area with habitat value for native flora and fauna is the Kern River Flood Control Channel (KRFCC), approximately 700 feet south of the HECA Project Site. The majority of the 653-acre Controlled Area may remain in active agriculture and act as a buffer between the Project and the KRFCC. The western border of the Tule Elk State Natural Reserve is approximately 1,700 feet to the east of the HECA Project Site.

Construction activities for the HECA Project will occur throughout the 42-month construction period. All construction laydown and parking areas will be within the HECA Project Site and the Controlled Area. Onsite construction activities include clearing and grubbing, grading, hauling, layout of equipment, delivery and handling of materials and supplies, and HECA Project construction and testing operations. The HECA Project Site occurs in an area of relatively flat topography. Site grading will occur as necessary to form level building pads for major process units.

Construction site access will be via Dairy Road for truck deliveries and Adohr Road for construction craft vehicles arriving and departing the site. Initial site preparation will include construction of temporary access roads, parking, laydown areas, office and warehouse facilities, installation of erosion control measures, and other improvements necessary for construction. Erosion control measures will include construction of stormwater retention basins and related site drainage facilities to control runoff within the HECA Project Site boundary. Existing drainage patterns outside the HECA Project Site boundary will remain unchanged, and no runoff from outside the HECA Project Site boundary will flow onto the HECA Project Site.

2.1.2 Electrical Transmission Line

An electrical transmission line will interconnect the HECA Project to PG&E's future switching station. The transmission line will be constructed and owned by HECA up to the point of interconnection. The power generated by the HECA Project will be connected to the existing PG&E system by a single-tower, 230-kilovolt transmission line that will be constructed as part of the HECA Project. This single-circuit line will be connected to a new switchyard at the HECA Project Site.

The proposed electrical transmission line route is approximately 2 miles long to HECA's property boundary, and passes through previously disturbed areas or active agriculture, predominantly pistachio orchards, alfalfa, and cotton. Construction of the line will require installing approximately 26 (15 offsite and 11 onsite) tubular-steel transmission structures and the supporting foundations.

The electrical transmission line route extends east from the HECA Project Site to a new PG&E switching station (adjacent to the existing Midway-Wheeler Ridge transmission lines) as shown on Figure 4, Project Location Details. The new PG&E switching station will be constructed at the eastern terminus of the electrical transmission line, approximately 2 miles east of the HECA Project Site and next to Elk Valley Road. Access to the switching station site would be along an existing unimproved farm road from Morris Road or Elk Valley Road. The electric transmission switching station will be designed, constructed, owned, and operated by PG&E.

The area occupied by the PG&E switching station will be approximately 417 feet by 417 feet. Portions of the site will be excavated to install a grounding grid, underground control and protection cabling, and foundations. It is anticipated that "dead-end" structures to terminate the transmission line from the HECA site would be approximately 30 feet tall near the western end of the switching station site. A similar set(s) of structures at the eastern end of the station for the incoming lines from Midway and the outgoing lines to Wheeler Ridge would also be required. The height of a two-level structure would be on the order of 50 to 60 feet. The station would also have structures associated with interconnecting buses and cable "drops" to the circuit breakers. The height of these structures would be on the order of 20 to 30 feet.

Approximately 15 steel poles are expected to be required outside of the HECA Project Site. Construction of the interconnection line will consist of installing footings, poles, insular and hardware, and pulling conductor and shield wires. The new transmission line interconnection will be placed in an approximately 100-foot-wide permanent right-of-way (ROW).

Construction of the new 230-kilovolt transmission line interconnection will require approximately 3 months. It will be scheduled for completion and be operational in time for generation testing of the HECA Project. HECA will provide for the transmission line via a Large Generator Interconnection Agreement up to the point of interconnection at the future PG&E switching station.

Upon completion of the linear installation, agricultural uses may be reestablished along the linear route within the 100-foot-wide permanent ROW. Orchards would be limited to 25 feet in height within the permanent ROW.

2.1.3 Natural Gas Supply

A 13-mile natural gas linear will interconnect with a PG&E natural gas pipeline north of the HECA Project Site. The interconnect will consist of one tap off the existing natural gas line, and one metering station at the beginning of the natural gas linear adjacent to a PG&E Inlet. The metering station will be up to 100 feet by 100 feet, and 8 feet tall, surrounded by a chain-link fence. In addition, there will be a metering station at the end of the natural gas linear, on the western side of the HECA Project Site, and a pressure-limiting station on the HECA Project Site. PG&E will construct and own the natural gas pipeline.

The majority of the natural gas linear extends across areas used for active agriculture and existing roadways. However, the natural gas linear is adjacent to several areas with natural habitat value near Interstate 5 (I-5) and at the northern terminus near Magnolia Avenue.

The natural gas linear would require a 50-foot construction ROW and a 25-foot permanent ROW; however, most of the ROW would be in cultivated fields or other disturbed habitat types adjacent to paved and unpaved roads.

Wetland features adjacent to the proposed natural gas linear ROW will be avoided. Non-wetland potential waters of the U.S. within the natural gas pipeline construction limits are degraded, seasonally ponded claypan depressions. If avoidance of non-wetland waters is not feasible, the feature(s) will be temporarily disturbed by the construction activities during installation of the natural gas pipeline, and the site will be restored to pre-construction condition.

Construction of the natural gas pipeline interconnection will involve a variety of crews performing the following typical pipeline construction activities: hauling and stringing the pipe along the route; welding, radiographic inspection, and coating the pipe welds; trenching; lowering the pipe into the trench; backfilling the trench; hydrostatic testing of the pipeline; tying into the existing pipeline; purging the pipeline; and cleaning up and restoring construction areas. Roads and ROWs will be restored to specifications of the involved agencies. Open trenching will be minimized, and trenches will be covered or ramped when left overnight. In areas with habitat value and in agricultural areas, the topsoil from the trenching will be set aside, preserved, and used to cover the excavation.

Construction of the natural gas pipeline interconnection will take approximately 6 months. It will be scheduled to be finished and operational in time to provide test gas to the HECA Project. Construction will occur in accordance with a traffic management plan to minimize impacts to traffic traveling on the affected roadways. Affected areas will be restored to their original state so as to minimize erosion.

2.1.4 Water Supply Pipelines

For process water, the HECA Project will use brackish groundwater supplied by the Buena Vista Water Storage District (BVWSD) via a new 15-mile pipeline. Potable water for drinking and sanitary use will be supplied by West Kern Water District (WKWD), who will construct a new 1-mile pipeline for that purpose. Installation of the process water and potable water pipelines will involve industry standard construction activities for pipelines, including trenching; hauling and stringing of pipe along the routes; welding; radiographic inspection and coating of pipe welds; lowering welded pipe into the trench; hydrostatic testing; and backfilling and restoring the approximate surface grade. Construction of the water pipelines is expected to take approximately 6 months to complete.

Process Water Supply Pipeline

A new 15-mile, 30-inch-diameter pipeline will convey brackish groundwater supplied from the BVWSD to be used for process water by the HECA project. BVWSD will construct and own the process water supply pipeline, and approximately 14.5 miles of the pipeline will be located in an existing BVWSD ROW. The proposed process water pipeline would be constructed entirely within an existing unpaved road, or within areas that are currently actively farmed; therefore, no direct impacts to natural habitats are anticipated. Once the process water is delivered to the HECA Project Site, the brackish water will be treated on site to meet all process and utility water requirements. The process water supply pipeline will be approximately 15 miles in length and will be constructed by BVWSD.

In addition, BVWSD will own, construct, operate, and maintain the well field that will provide brackish groundwater for the HECA Project's process water supply. This well field will be in the northwestern portion of BVWSD's service area within active agricultural fields near the West Side Canal, in the vicinity of Seventh Standard Road, at the northern end of the 15-mile-long process water line. It is currently anticipated that there will be up to five groundwater extraction wells. Two of these wells will provide operational redundancy. The maximum depth of the wells will be approximately 300 feet below ground surface. The brackish water will be treated at the Project Site to meet all process and utility water requirements. The process water supply pipeline would require a 50-foot construction ROW and a 25-foot permanent ROW.

BVWSD addressed the groundwater extraction wells and the process water supply pipeline in their Draft and Final Environmental Impact Reports for BVWSD's Groundwater Management Program, issued in October 2009 and December 2009, respectively (BVWSD, 2009a; 2009b). The Final Environmental Impact Report for the Groundwater Management Program (State Clearinghouse No. 2009011008) concludes that the wells and the process water pipeline do not result in significant impacts to any federally listed species.

Potable Water Pipeline

For drinking and sanitary use, the HECA Project will use potable water supplied by WKWD. A new 4-inch-diameter potable water line will be constructed, owned, and maintained by HECA LLC.

The potable water line would be approximately 1 mile in length. This pipeline will require a 10-foot construction and permanent ROW that will be placed within the proposed electrical transmission line ROW. Most of the proposed ROW is within or adjacent to existing dirt access roads, or in cultivated fields.

2.1.5 Industrial Railroad Spur

The industrial railroad spur is approximately 5 miles long and will connect the HECA Project Site to the existing San Joaquin Valley Railroad Buttonwillow Branch (formerly called the SP Buttonwillow Branch). Two public at-grade crossings may be required, and several private crossings will be needed for farmers' access to croplands and the irrigation canal. The industrial railroad spur would require a 75-foot construction ROW, 60-foot permanent ROW, and 3-acre rail laydown area.

2.1.6 OEHI Carbon Dioxide Pipeline

An approximately 3.4-mile-long CO_2 12-inch-diameter pipeline will be constructed to transfer the CO_2 from the HECA Project Site to the OEHI CO_2 Processing Facility used by OEHI for injection into deep underground hydrocarbon reservoirs for CO_2 EOR and sequestration. Additional components of the CO_2 pipeline will include metering facilities at the pipeline origin and terminus, a cathodic protection system, and four emergency block valves. Two of the block valves will be automated and two will be manual block valves.

The CO_2 pipeline route originates at the southern portion of the HECA Project Site and will be constructed using a combination of standard open-trench installation and Horizontal Directional Drilling (HDD). One HDD will be approximately 500 feet in length under the levees associated with the West Side/Outlet Canal crossing. A second HDD will be approximately 2,000 feet long, and will be used to install the pipeline under the KRFCC and the California Aqueduct. On the southern side of the Aqueduct, the pipeline alignment extends southeast and south to the OEHI CO_2 Processing Facility, and parallels existing private roads. OEHI will construct and own the pipeline.

With the exception of HDD crossings where the depth of the CO_2 pipeline may reach 100 feet below grade, the CO_2 Pipeline will be buried approximately 5 feet below grade. Installation of the CO_2 supply pipeline will involve typical construction activities, including trenching; hauling and stringing pipe along routes; welding; radiographic inspection and coating pipe welds; lowering welded pipe into the trench; backfill of the trench; hydrostatic testing of the pipeline; purging the pipeline; and cleanup and restoration of construction areas. Grade cuts will be restored to their original contours, and affected areas will be restored to their original condition to minimize erosion. The pipeline will be protected by cathodic protection, and monitored by independent leak-detection systems.

Construction of the CO_2 pipeline is expected to take approximately 6 months to complete. The CO_2 pipeline would require a 50- to 80-foot construction ROW and a 25-foot permanent ROW.

HDD involves using a drilling rig that will bore a horizontal hole under water crossings. At each of these crossings, a laydown area (or entry/exit pit) has been identified on either side of the water course to accommodate the HDD installation (see Figure 4, Sheet 4, Project Location Details). The temporary disturbance area would be approximately 120 feet by 100 feet for each HDD entry pit; and approximately 75 feet by 100 feet for each HDD exit pit (Stantec, 2012b).

Best management practices for HDD will include silt fencing around the drill sites, energy dissipation devices for discharging water from hydrostatic testing of the pipeline, selecting drilling fluids for environmental compatibility, and removing spent fluids from the areas immediately adjacent to the water bodies for safe disposal and to prevent contamination. In addition, soil erosion control measures will be implemented to prevent runoff and impacts to water quality.

2.1.7 OEHI Carbon Dioxide EOR Processing Facility

The CO_2 from the HECA plant will be received by the CO_2 EOR Processing Facility, which will be located at the southern terminus of the CO_2 Pipeline in the southeastern quarter of Section 27S. The CO_2 EOR Processing Facility will include the Central Tank Battery (CTB), Reinjection Compression Facility (RCF), CO_2 Recovery Plant (CRP), and a Water Treatment Plant. The CO_2 EOR Processing Facility is expected to occupy and permanently disturb an area of 1,200 feet by 2,200 feet (60.61 acres). These dimensions do not include the area of the CO_2 Pipeline or the Satellite Gathering Stations.

Central Tank Battery

The CTB is the primary oil/water separation system for the CO_2 EOR process. The inlet liquid gathering lines from the Satellite Gathering Stations will be manually directed to one of the three gas separator tanks. The gas from this process will be combined with the gas from the gas separators. The oil and water will be separated, and the oil will be skimmed off and pumped to Section 18G and metered for sale. The partially treated water will be conveyed via pipeline to the existing water treating facilities.

Water Treatment Plant

The oily water from the inlet section of the CTB will be treated to remove oil, solids, and other contaminants from the produced water. The produced water will be pressurized in the injection pumps and sent to the satellites for injection. Low-pressure gas collected from the CTB will be compressed and then routed to the inlet of the RCF and the CRP for processing.

Reinjection Compression Facility

The RCF will be the first portion of the CO_2 treating/recovery facilities to be installed. Produced gas from the Satellite Gathering Stations (see Section 2.1.8) will initially flow to the RCF. At the RCF, the CO_2 gas will be dehydrated, compressed, blended with CO_2 purchased from the HECA Project, and re-injected into a closed-loop system.

CO_2 Recovery Plant

The CRP is the second part of the gas treating/recovery plant. This facility will separate CO_2 from produced hydrocarbon gas and recycle the separated CO_2. The CRP will consist of several processing units for the separation of the CO_2 from the recovered natural gas. The CRP is not expected to be constructed until 2020, and would not be part of the Demonstration Period defined by DOE.

2.1.8 OEHI Satellite Gathering Stations

The Satellite Gathering Stations (satellites, also known as Production/Well-Testing Satellites) will be a series of facilities that will provide primary separation of the oil/water and gas from the production well stream. Initially, three satellites are scheduled to be installed to handle the expected production for the first several years of the field development during the Demonstration Period. Satellites 1, 2, and 3 are each expected to have a permanent surface footprint of 230 by 200 feet. This footprint is included in the total area of the OEHI Project site evaluated in this Biological Assessment.

Each satellite will be equipped with an inlet manifold in which well flow lines associated with that satellite are connected. Flow from each well flow line will be diverted into either the production separator or the test separator via automated manual valves. The production separator is a two-phase separator to handle primary vapor liquid separation of the fluid recovered from the production wells at each satellite. The gases will be separated and routed to the inlet of the RCF. The entire field production pressure will be controlled at the RCF inlet header, and the individual satellites will “float” on that pressure.

Liquid and gas flow rates will be metered for production trending and monitoring. The test separator will be a three-phase, bucket and weir separator to allow for a 24-hour test cycle of each well serviced by that satellite. The oil and water will be controlled by level control, and the gas will be controlled by a back-pressure controller to hold the test separator pressure slightly above that of the associated production separator. Oil, water, and gas from the test separator will be re-combined and directed to the inlet manifold and then to the production separator.

2.2 OPERATION AND MAINTENANCE

This section describes the operation and maintenance of the HECA and OEHI projects.

2.2.1 HECA Project

HECA Project operation and maintenance will occur within the HECA Project Site. The adjacent Controlled Area will remain in active agriculture similar to the existing condition. Access to linears will be limited in nature, and will be along existing access roads or access roads developed during initial installation activity. HECA LLC will own, operate, and maintain the approximately 2-mile transmission line up to the interconnection with a future PG&E switching station. It is anticipated that annual maintenance of the electrical transmission line will be provided for under an agreement between PG&E and the Project. The electrical transmission line is located entirely within areas that are actively farmed or are developed. Most of the maintenance will be routine and can be scheduled during periods when damage to the crops and land can be minimized. Maintenance activities will be conducted by personnel trained to be aware of the presence of sensitive wildlife.

PG&E will own, operate, and maintain the natural gas pipeline. Maintenance of the natural gas pipeline would follow PG&E corporate policies and protocols. Long-term maintenance needs of the natural gas pipeline would be minimal during the 25-year lifespan of the Project; therefore, they are not quantified in this document.

BVWSD will own, operate, and maintain the approximately 15-mile, 30-inch-diameter process water pipeline and associated wells. Annual maintenance of the process water pipeline and associated groundwater wells would be conducted by BVWSD. Maintenance activities of the wells and the pipeline would follow BVWSD corporate policies and protocols. Long-term maintenance needs of the process water pipeline would be minimal during the 25-year lifespan of the Project, and therefore is not quantified in this document.

HECA LLC will own, operate, and maintain the approximately 1-mile potable water pipeline. Maintenance activities of the pipeline would include:

- Annual reconnaissance of the pipeline ROW;
- Annual inspection and exercising (opening and closing for one cycle) of valves, as necessary;
- Annual vegetation removal, re-grading, and application of dirt for the access road after wet periods and pipe work, as necessary; and

- Replacement of pipeline components (lining and coating, valves, and joints), as determined necessary by routine inspection.

Long-term maintenance needs of the potable water pipeline would be minimal during the 25-year lifespan of the HECA Project; therefore, they are not quantified in this document.

HECA LLC currently anticipates that it will own, operate, and maintain the approximately 5-mile railroad spur. Regardless of final ownership of the spur, maintenance activities will consist of routine annual maintenance activities and programmed maintenance conducted on a periodic basis. Annual maintenance activities consist of visual inspections, vegetation control, spot surfacing and lining of rough spots in the track, and adjusting/lubrication of turnouts. In addition, any warning devices at road crossings will be inspected as frequently as monthly.

Programmed major maintenance consists of surfacing and lining the rail line, typically every 3 to 5 years; replacing the rail, potentially once during the life of the HECA Project; and replacing 15 percent of the timber ties on a 10-year cycle. If concrete ties are used, the ties will not need to be replaced. Major maintenance activities will be conducted using on-track equipment. Replaced materials will be removed from the ROW and recycled. Timber ties will be disposed of by incineration, landfill disposal, or other approved disposal options.

2.2.2 OEHI Project

OEHI will own, operate, and maintain the CO_2 pipeline and the related components of the OEHI Project. Maintenance of the CO_2 pipeline and other EOR facilities will follow existing OEHI operational procedures as required by the existing USFWS Biological Opinion (Appendix A) and the related 1997 MOU between OEHI and the CDFG (Appendix B), which has twice been updated and remains in effect until 2014 (CDFG, 1997; 1999; 2010). The EOR facility operations will be similar to the existing facility operations by OEHI at the EHOF. Operations activities include facility inspection and maintenance. Maintenance needs of the CO_2 pipeline and associated EOR facilities would be minimal during the Demonstration Period of the Project; therefore, they are not quantified in this document.

2.3 PROPOSED CONSERVATION MEASURES

This section describes the conservation measures that are included in the HECA Project and the OEHI Project to avoid, minimize, and/or compensate for impacts on listed species.

2.3.1 HECA Project Design Modifications

The HECA Project design has been refined in coordination with the resource agencies and environmental specialists to avoid and minimize impacts on sensitive biological resources to the extent practicable. These measures include relocating the HECA Project Site from the originally proposed location to its current location across the Aqueduct to reduce impacts to the blunt-nosed leopard lizard; and relocating the natural gas pipeline to avoid portions of the Coles Levee Ecosystem Preserve. In addition, the potable water linear and electrical transmission linear were shortened and relocated to the east of the HECA Project Site, which avoided impacts to 1.9 acres of Allscale Scrub habitat.

The HECA Project also includes general and species-specific measures to avoid and minimize impacts on listed species and their habitat. For potential impacts on listed species that remain after implementation of feasible avoidance and minimization measures, comprehensive compensatory measures through habitat enhancement, establishment, and preservation are included in the Project to offset potential losses of listed species or their habitat. HECA LLC is committed to implementing these measures as part of the Project. These conservation measures are extracted from the Amended Application for Certification (AFC) submitted to the CEC in May 2012, and the corresponding numbers or mitigation measures from the 2012 Amended AFC (e.g., BIO-1, BIO-2, etc.) are provided where applicable.

2.3.2 OEHI Project Design

The proposed CO_2 pipeline crossings of the West Site Canal/Outlet Canal, the KRFCC, and the California Aqueduct will be constructed using HDD to avoid direct and indirect effects to species movement and dispersal at these locations.

OEHI will minimize impacts associated with the OEHI Project by using existing wells and previously disturbed areas to the maximum extent feasible. Avoidance and minimization will also be achieved by minimizing future land disturbance on those portions of the EHOF considered high value on the HCP multi-species map. The OEHI Project will also be implemented in compliance with the 1995 Biological Opinion issued by the USFWS (Appendix A), and a related 1997 MOU between OEHI and the CDFG, as updated (Appendix B). Finally, the OEHI Project will be implemented in compliance with a 50-year HCP for the EHOF, which is currently under development and anticipated to be approved by the end of 2013.

2.3.3 General Avoidance and Minimization Measures

HECA will implement the following general measures to avoid and minimize potential adverse effects to special-status biological resources. The OEHI Project will implement the avoidance and minimization measures in the 1995 Biological Opinion issued by the USFWS and 1997 MOU between OEHI and the CDFG, as amended in 1999 and 2010; and the HCP for the EHOF, when approved.

Biological Resource Mitigation Implementation and Monitoring Plan (BIO-17)

Prior to ground-disturbing activities, HECA will develop a Biological Resource Mitigation Implementation and Monitoring Plan (BRMIMP) in coordination with the CEC, CDFG, and USFWS. The BRMIMP will identify the biological mitigation, monitoring, and compliance measures that will be implemented during construction of the HECA Project. The measures identified in the BRMIMP will address each of the avoidance and minimization measures below, in addition to the terms and conditions of the permits and approvals by the CEC, USFWS, and

CDFG. The BRMIMP will include the qualifications, responsible parties, and schedules for implementing each of the avoidance and minimization measures described below. A draft BRMIMP will be submitted to the CEC, USFWS, and CDFG for review prior to the start of ground-disturbing activities.

Construction Worker Education Program (BIO-7)

A worker education program will be implemented for all HECA Project construction personnel. These personnel will be required to read educational materials and attend an education class given by a qualified biologist. The brochure and class will describe the special-status species that could be encountered, the regulatory protection of the species, and appropriate measures to take upon discovery of a special-status species.

Construction personnel will be instructed to set equipment off the ground when possible to minimize access to small mammals. All work areas will be kept clear of trash and food items to minimize attracting wildlife. Construction techniques to minimize potential adverse impacts will also be presented, such as filling or covering excavations. If excavations are to be left open overnight, ramps will be installed to allow wildlife to escape.

The names and affiliations of all people trained will be documented, and submitted to the CEC, USFWS, and CDFG (see measure BIO-17).

Operations and Maintenance Education Program (BIO-8)

The worker education program will be implemented for HECA Project operations and maintenance personnel. Personnel will be instructed to be alert to and aware of the presence of special-status wildlife. If any special-status wildlife is spotted, activities in the vicinity of the sighting that could impact the species will be halted, and the animal allowed to move away from the activity area.

2.3.4 Special-Status Plant Avoidance, Minimization, and Conservation

The following measures will be implemented to avoid and minimize potential adverse effects to special-status plant species.

Special-Status Plant Pre-Construction Survey (BIO-1)

Qualified biologists will conduct a special-status plant pre-construction survey of the affected areas for the HECA Project and within 200 feet of the affected areas, or to the property boundary if less than 200 feet, and if permission from the adjacent landowner cannot be obtained. Surveys will be conducted according to Protocols for Surveying and Evaluating Impacts to Special-Status Native Plant Populations and Natural Communities (CDFG, 2009). Special-status plants will be identified, counted, and mapped. Populations of special-status plants will be monitored through the course of the year to determine how many mature and bloom. The results of all pre-construction surveys will be documented, and submitted to the CEC, USFWS, and the CDFG (see conservation measure BIO-17).

Special-Status Plant Avoidance (BIO-2)

If listed plant species are present that will be affected by construction within the HECA Project area, direct impacts to the plants will be avoided, to the greatest extent feasible.

Special-Status Plant Mitigation (BIO-3)

During construction, construction equipment that travels off the Project Site will be cleaned to remove dirt and seeds of noxious weeds. Native plants will be reestablished in areas where construction activities temporarily disturb natural vegetation. Post-construction monitoring will be conducted, and additional control measures such as hand removal, mowing, or herbicide application will be implemented as needed to minimize the establishment of noxious or invasive species (as defined by the California Agricultural Department and/or the California Invasive Plant Council) in areas where natural vegetation was removed during construction.

For permanent impacts to populations of California Native Plant Society (CNPS)-Ranked plant species that cannot be avoided, disturbance will be timed until after available seeds can be collected. These seeds will be properly stored, and then scattered over a suitable area near the parental site just prior to the first rains of the season.

Prior to temporary disturbance of special-status plant occurrences, seeds will be collected and properly stored for replanting after completion of construction. During construction, the topsoil will be salvaged and replaced on site after construction is completed. After work is completed in that area, the topsoil will be replaced and the seeds will be redistributed prior to the first rains of the season.

Both types of the above-mentioned re-seeded areas will be demarcated in the field, mapped, and monitored post-construction for 3 years. If the re-seeded areas have not met the performance criteria established in the BRMIMP after 3 years, additional monitoring will be conducted based on coordination with the resource agencies. Monitoring will be conducted during the early spring to determine whether the target species are present and whether weed species are common. Weeding will occur if weed species appear abundant or are adversely impacting the target species. Weeding will be done in a fashion that will minimize impacts to special-status plant or animal species and other native species, but may include hand-weeding, weed-whacking, or spraying with an agency-approved herbicide.

As part of the BRMIMP, a monitoring report will be submitted by HECA to the CEC and CDFG each year for 3 years that will document the status of each population, weeding efforts that have been undertaken, and suggested work for the next season (see measure BIO-17); these reports will be available to USFWS, if requested.

It is anticipated that these measures will be sufficient to avoid significant impacts to any special-status plant species that may be present.

2.3.5 Special-Status Wildlife Avoidance and Minimization Measures

The following measures will be implemented to avoid and minimize potential adverse effects to special-status wildlife species.

Terrestrial Wildlife Pre-Construction Survey (BIO-4)

Pre-construction surveys will be conducted in affected areas that have potentially suitable habitat for blunt-nosed leopard lizard, San Joaquin kit fox, giant kangaroo rats, and Tipton's kangaroo rats. Surveys will be conducted less than 2 weeks prior to the start of ground disturbance within the affected areas and adjacent habitats within 200 feet of the affected areas, or to the property boundary if less than 200 feet, and permission from the adjacent landowner cannot be obtained. Efforts will include visual surveys for blunt-nosed leopard lizard, San Joaquin kit fox, giant kangaroo, rats and Tipton's kangaroo rats. Visual surveys will also be conducted for Buena Vista Lake shrew in areas within the process water pipeline construction limits that are adjacent to the West Side Canal and the Kern River Flood Control Channel.

All sightings and/or signs of sensitive wildlife will be mapped using a global positioning system device. The results of all pre-construction surveys will be documented, and submitted to the CEC, USFWS, and CDFG (see measure BIO-17).

Site Clearance Prior to Ground Disturbance (BIO-5)

Prior to ground-disturbing activities in undeveloped and uncultivated lands within the HECA Project area, surveys will be conducted to determine whether San Joaquin kit fox, small mammals, or blunt-nosed leopard lizards are present. To ensure that no blunt-nosed leopard lizards are taken during the initial site preparation, each area with potential habitat will be surveyed by a CEC-approved biologist according to the standard protocols for survey timing and ambient temperature. These surveys will occur prior to any ground disturbance. Exclusion fencing will be installed around the perimeter of the work area to ensure that no wildlife re-enters. Exclusion fencing will consist of tin flashing (or other material approved by CDFG and USFWS) that will be buried at least 9 inches underground, and rise at least 2 feet above the ground.

Once the exclusion fencing has been established, the area will be visually surveyed during the day for wildlife, and small mammals will be trapped and relocated (see conservation measure BIO-15) during the night. All surveying and trapping efforts will be conducted in a manner that minimizes collapsing any small mammal burrows. Tracking stations will be used to determine whether there are additional individuals in the area.

The HECA Project construction areas will be surveyed daily for blunt-nosed leopard lizards when soil and air temperatures are within CDFG survey protocol limits. An area will be deemed clear of any blunt-nosed leopard lizards after there have been no signs or sightings for 5 survey days. If a blunt-nosed leopard lizard is observed within the construction area, the exclusion fencing will be opened to allow the lizard to leave on its own accord. Once the lizard has left the area, the exclusion fencing will be closed and surveyed until there are no signs or sightings of blunt-nosed leopard lizards for 5 consecutive days.

Exclusion fencing will be left in place only for as long as needed to complete the work. For installation of the Project linears, no one area is likely to be closed for more than 6 months. The fencing will be inspected and maintained daily by the approved biologist. If the exclusion fencing is compromised (by wind or other means) and left open, an approved biologist will repair the fencing and determine if the area will need to be re-surveyed and/or re-trapped for wildlife.

To confirm that BIO-5 is successful, ground disturbance will be monitored (see measure BIO-16).

The results of the blunt-nosed lizard surveys and area clearance will be documented, and submitted to the CEC, USFWS, and CDFG (see measure BIO-17).

Predatory Bird Minimization Measures (BIO-6)

Several species of raptors and corvids (such as common ravens, American crows, and red-tailed hawks) are known to prey on blunt-nosed leopard lizards; common ravens are the most abundant potential avian predator in the Action Area. The HECA Project transmission design has been modified to incorporate elements to discourage raven nesting. For example; instead of lattice-style transmission towers, the HECA Project will use a single-pole transmission line design that minimizes potential perches and nesting sites. The proposed single-pole design is consistent with the Avian Power Line Interaction Committee's suggested practices for avian protection on power lines (APLIC, 2006).

To minimize the number of common ravens in the area, no raven will be allowed to nest in the HECA Project transmission towers within 1 mile of known blunt-nosed leopard lizard habitat. Raven nests will be removed by a CEC-approved biologist prior to egg-laying in early spring. For all bird nests removed, documentation will be prepared by HECA and submitted to the CEC, USFWS, and CDFG (see measure BIO-17).

San Joaquin Kit Fox Mitigation (BIO-14)

Disturbance (including any excavation and/or destruction) to all San Joaquin kit fox dens shall be avoided to the maximum extent possible, and shall only occur in accordance with the protocol described in the Standardized Recommendations for Protection of the San Joaquin Kit Fox Prior to or During Ground Disturbance (USFWS, 1999b), or as approved by the wildlife agencies. In essence, the following hierarchy shall be adhered to:

1. Pre-construction surveys shall be conducted by the CEC-approved biologist no less than 14 days and no more than 30 days prior to the beginning of ground disturbance and/or

construction activities or any HECA Project activity likely to impact the San Joaquin kit fox. Surveys shall identify kit fox habitat features on the HECA Project Site, and evaluate use by kit fox; and if possible, assess the potential impacts to the kit fox by the proposed activity. The status of all dens will be determined and mapped, and all appropriate equipment exclusion zones (per den type) will be demarcated in a manner that sufficiently alerts equipment operators of the exclusion zone.

2. Regardless of time of year, no natal kit fox dens will be excavated unless authorized by the Wildlife Agencies. Other den types may be excavated only by agency-approved biologists, and only after occupancy status has been determined. Excavation and/or destruction of dens would then be allowed in accordance with the procedures specified in Standardized Recommendations (USFWS, 1999b), or as approved by the wildlife agencies.

3. All known and natal kit fox dens that are slated for destruction will be replaced. Prior to destruction of an active den, artificial replacement dens will be constructed outside the buffer zone. Replaced dens will be constructed according to protocols set forth by the Wildlife Agencies. The replacement ratio will be 1:1 for non-natal dens. If excavation or destruction is approved by the Wildlife Agencies, replacement ratios will be 2:1 for natal dens.

The results of all den assessments, burrow scoping, and excavation activities will be documented, and submitted to the CEC, USFWS, and CDFG (see measure BIO-17).

Small Mammal Mitigation (BIO-15)

Construction work areas will be surveyed and small mammals will be relocated as necessary prior to any ground disturbance to minimize impacts to small mammals during the initial site preparation; work areas will be cleared in accordance with the *Survey Protocol for the Morro Bay Kangaroo Rat* (USFWS and CDFG, 1996), or as determined in consultation with either CDFG or USFWS. Areas will be secured prior to this effort so that wildlife species cannot re-enter the area (in conjunction with conservation measure BIO-5).

Small mammal trapping and relocation will be conducted for 5 consecutive nights, or until no animals are caught on 2 consecutive nights per area. The small mammal trapping surveys would occur within the construction work areas in potentially suitable habitat (alkali desert scrub, pasture, annual grassland, and barren) that contains evidence of small mammals. Traps will be set according to "sign" (burrows, trails, scat, etc.) and/or in areas of high habitat quality. Small mammal trapping and relocation will be performed by a qualified biologist(s) approved by the CEC with the necessary permits. The results of the small mammal trapping and area clearance will be documented, and submitted to the CEC, USFWS, and CDFG (see Mitigation Measure BIO-17).

2.3.6 Monitoring and Mitigation Reporting

Ground-Disturbance Monitoring for Terrestrial Wildlife (BIO-16)

Construction activities in areas with habitat value for listed species will be monitored by a qualified biologist while the top 18 inches of soil are initially disturbed. The biologist(s) will watch for any special-status animals and will have the authority to stop work if a listed wildlife species is encountered in the construction area. If authorized to remove and/or relocate the species, biologists will relocate the animal to the nearest safe location. If the species cannot be legally relocated, work at that location will be shut down and all personnel will be required to leave the area. The approved biologist will watch the wildlife in question from a distance until the individual has left the area. The results of all construction monitoring will be documented, and submitted to the CEC, USFWS, and CDFG (see Mitigation Measure BIO-17).

Reporting to Agencies (BIO-17)

During construction, a quarterly BRMIMP report will be prepared by HECA and submitted to the CEC, CDFG, and USFWS. The report will be submitted by the 20th of the following month (i.e., the report for May will be submitted by June 20). If the 20th falls on a weekend or holiday, the report will be due the first business day following the 20th. To reduce the use of paper, the BRMIMP may be submitted on compact disc (CD) or electronically, as directed by each agency.

During construction at the HECA Project Site, a CEC-approved biologist will examine active work areas every day prior to the onset of activities to ensure that no special-status species are in the area, and that all wildlife barriers are still in place. Biologists will inform the construction crews when areas are clear, and report significant observations of wildlife to the agencies, as required in the BRMIMP.

2.3.7 Habitat Compensation

HECA LLC will implement the following compensation for temporary and permanent losses of habitats used by special-status species due to construction and operation of the HECA Project. Compensation would include offsite acquisition, preservation, and enhancement of land potentially used by one or more of the affected special-status species.

HECA Project Sensitive Habitat Mitigation (BIO-18)

HECA will compensate for the permanent and temporary loss of habitats potentially used by federally and state-listed species by acquiring credits from the USFWS-approved Kern Water Bank Authority mitigation bank.

HECA LLC will acquire USFWS-approved mitigation credits that meet the habitat and/or species requirements of the federally and state-listed species that would be affected by the proposed action. The compensation proposal consists of the following components:

- Compensation for temporary habitat loss associated with construction of the natural gas pipeline: a total of 8.0 acres (credits) would be acquired to compensate for 3.7 acres of natural vegetation that would be temporarily removed during construction.
- Compensation for permanent habitat loss associated with construction of the Project Site, the railroad spur, the natural gas pipeline, and the PG&E switching station: a total of 47 acres (credits) would be acquired to compensate for the permanent loss of 466 acres of cultivated fields that may be used infrequently by San Joaquin kit fox for movement and migration.

OEHI Project Sensitive Habitat Mitigation

OEHI will provide compensation for the OEHI Project, including the CO_2 pipeline, in accordance with the 1995 USFWS Biological Opinion concerning oil production at Maximum Efficient Rate on Elk Hills Naval Petroleum Reserve (USFWS File # 1-1-95-F-102) and the draft HCP currently under review by the USFWS.

2.4 PROJECT SCHEDULE

The anticipated schedule milestones for the Project are as follows:

DOE submits Biological Assessment to USFWS .... March 2013
USFWS finalizes Biological Opinion .... May 2013
Completion of CEC permitting process .... June 2013
Commencement of pre-construction and construction activities .... June 2013
Commencement of truck deliveries and ground disturbance .... August 2013
Completion of construction .... February 2017
Commencement of pre-commissioning and commissioning .... March 2016
Commencement of commercial operation of the Project .... September 2017

3.0 ACTION AREA AND ENVIRONMENTAL SETTING

The following is a discussion of the environmental settings and biological resources currently present in the Action Area, defined in this report as the 453-acre Project Site, the 4-acre PG&E switching station, the OEHI Project Site, and the construction footprints of the associated linear facilities and associated buffers per CEC guidelines (1-mile buffer from the HECA Project Site and 1,000-foot buffer from all associated linear facilities as shown in Figure 5). Information regarding the environmental setting within 35 miles of the HECA Project Site is included when a regional perspective is required.

3.1 PROJECT SETTING

The HECA Project Site is in unincorporated Kern County approximately 2 miles northwest of the unincorporated community of Tupman, and south of Adohr Road. The land use in this portion of Kern County is resource-based oil exploration and production, which provides a large segment of the employment base. Clay mineral extraction also occurs in the area. The 453-acre HECA Project Site is comprised of portions of two agricultural parcels in Section 10 within Township 30 South, Range 24 East.

The HECA Project Site is currently used for farming purposes, including cultivation of cotton, alfalfa, and onions. Land surrounding the HECA Project Site, including the Controlled Area, is also used primarily for farming, particularly the cultivation of alfalfa and cotton. The Outlet Canal, KRFCC, and the California Aqueduct (State Water Project) are 500, 700, and 1,900 feet south of the Project Site, respectively. The western border of the Tule Elk State Natural Reserve is approximately 1,700 feet to the east of the Project Site. The nearest single-family dwellings are approximately 1,400 feet to the east. HECA LLC has an option to purchase the HECA Project Site and Controlled Area.

Land uses in the vicinity of the approximately 13-mile-long natural gas pipeline route are primarily active agricultural land (mainly alfalfa cultivation), disturbed and/or developed areas, and patches of open/undeveloped land (Allscale Scrub).

Land uses in the vicinity of the approximately 15-mile-long process water pipeline are primarily farming (mainly alfalfa, cotton, and wheat cultivation), and orchards (pistachio). Much of the land between the West Side Canal and the KRFCC is Allscale Scrub.

Land uses in the vicinity of the approximately 1-mile-long potable water pipeline consist of previously disturbed habitat and farming (mainly alfalfa, cotton, oat, and wheat cultivation).

Existing land uses in the vicinity of the approximately 2-mile-long electrical transmission line consists of previously disturbed habitat and farming (mainly alfalfa, cotton, oat, and wheat cultivation). The new PG&E switching station at the terminus of the electrical transmission line would occupy approximately 4 acres in a field that is currently cultivated for alfalfa.

The OEHI Project Site consists of approximately 64 acres that will be permanently developed during the Demonstration Period of the project, and approximately 29 acres that will be temporarily disturbed to construct the CO_2 Pipeline. The EHOF is a mix of developed lands used for oil production and undeveloped lands. Land uses in the vicinity of the OEHI Project include farming (mainly alfalfa cultivation), open/undeveloped land (Allscale Scrub; Sawyer, Keeler-Wolf, and Evens, 2009), and resource extraction (oil production). The CO_2 pipeline would cross under the West Side/Outlet Canal, KRFCC, and the California Aqueduct using HDD.

3.1.1 Existing Conservation Lands in the Project Vicinity

Existing conservation lands within 35 miles of the HECA Project Site are listed in Table 2; Figure 5, Existing Natural Resource Conservation Areas, shows those areas within 10 miles, with the exception of the *Elk Hills Unit Draft Habitat Conservation Plan* area, whose boundaries have not yet been published.

Table 2
Existing Natural Resource Conservation Areas near the HECA Project Site

Conservation Area	Approximate Distance (miles)	Direction from HECA Project Site
California Aqueduct San Joaquin Draft Habitat Conservation Plan (developed by Department of Water Resources)	0.3	Southeast
Tule Elk State Reserve	0.3	East
Lokern Ecological Reserve	0.5	South
Occidental of Elk Hills, Inc., Elk Hills Unit Draft Habitat Conservation Plan	1.0	South
Kern Water Bank	1.0	East
Coles Levee Ecosystem Preserve	3.5	Southeast
Buttonwillow Ecological Reserve	6.5	North
Buena Vista Aquatic Recreation Area	7.8	Southeast
Northern Semitropic Ridge Ecological Reserve	22.5	Northwest
Carrizo Plain National Monument	22.7	West
Kern and Pixley National Wildlife Refuges	33.4	Northwest

3.2 CRITICAL HABITAT

Neither the HECA Project nor the OEHI Project would impact any USFWS-designated critical habitat. The nearest critical habitat is for Buena Vista Lake shrew, which is more than 20 miles to the southeast of the HECA Project Site (USFWS 2005).

3.3 ONGOING ACTIVITIES

Numerous ongoing activities in the Action Area may be affecting sensitive habitat, or federally listed plants or wildlife. To the east of the California Aqueduct are areas of active agriculture, active oil and gas extraction, and areas subject to periodic flooding as part of a water-banking system. The EHOF, located south of the California Aqueduct, is one of the most productive oil fields in the western United States, with thousands of existing production wells; it has been in production for decades.

4.0 CONSIDERATION OF FEDERALLY LISTED SPECIES

This section describes the methods used to characterize the HECA Project and OEHI Project's environmental setting and biological resources, and discusses the eight federally listed species with the potential to occur within the Action Area. Giant garter snakes are also included because they historically occupied the Action Area, but are presumed to be extirpated from the area.

4.1 EVALUATION METHODS

The Action Area evaluated for biological resources includes the area within a 1-mile radius of both the 453-acre Project Site and the OEHI Project Site, as well as the area within 1,000 feet of all proposed linear facilities. The proposed linear facilities surveyed by HECA included the process and potable water line corridor, the natural gas pipeline corridor, the railroad spur, the CO_2 pipeline route, and the transmission line route, where access was granted. These surveyed areas are shown on Figure 5, Existing Natural Resource Conservation Areas. In addition to the surveys conducted by HECA, OEHI biologists conducted surveys of the current CO_2 pipeline route and associated facilities in the EHOF.

The impact assessment for biological resources included informal consultation with resource management agencies, literature review, and preliminary field surveys. The literature search included an examination of environmental documents from adjacent and nearby areas, and a review of pertinent maps, scientific literature, and regional biological field guides. Key resources and references include the following:

- Recovery Plan for Upland Species of the San Joaquin Valley, California (USFWS, 1998)
- 2001 Special-status plant species survey results at Elk Hills Oil Field, Kern County, California (Quad Knopf, 2001)
- Supplemental Environmental Information, Occidental of Elk Hills, Inc., CO_2 Enhanced Oil Recovery Project (Stantec, 2012a)
- Modified CO_2 Supply Line Alignment Data Gap Analysis (Stantec, 2012b)
- Endangered Species Program 2011 Annual Report (OEHI, 2012)
- Coles Levee Ecosystem Preserve 2007 Annual Report (Live Oak, 2008a)
- Kern Water Bank Authority Habitat Conservation Plan/Natural Community Conservation Plan 2007 Compliance Report and Management Plan (Kern Water Bank Authority, 2008)
- California Natural Diversity Database (CDFG, 2012a)

A summary of the biological resources surveys performed is provided in Table 3. Qualifications of the biologists who contributed to the BA are provided in Appendix D. Plant species observed during these field surveys are listed in Appendix E, and wildlife species observed are provided in Appendix F. Additional wildlife surveys, including protocol surveys for blunt-nosed leopard lizard, were conducted for the OEHI project components in 2012 (Stantec, 2013).

Table 3
Biological Resources Field Surveys

Resource	Field Surveys Completed	Conducted by URS Biologists(s)
General biology	Habitat assessment, small mammal evaluation, general reconnaissance conducted for the process water linear on April 13 and April 24, 2008	Alex Brown and Julian Valenzuela
General biology	Habitat assessment, small mammal evaluation, general reconnaissance conducted for the CO_2 gas linear route on May 20, 2008	David Kisner
Potential jurisdictional wetlands	Habitat assessment in the vicinity of the CO_2 linear route, conducted on March 5, 6, and 20, 2008 and May 28, 2008	David Kisner and Alyssa Berry
General biology	Habitat assessment of the Project Site on December 30, 2008	David Kisner and Cletis England
General biology	Habitat assessment of the Project Site on January 8 and 9, 2009	Cletis England, Alyssa Berry, Robin Murray, Ronald Cummings, David Compton, and Jessica Birnbaum
Special-status wildlife, and potential jurisdictional wetlands	Rare plant, wildlife, and potential jurisdictional wetlands surveys in the vicinity of the CO_2 linear on March 17, 18, and 26, 2009	David Kisner, Wayne Vogler, Alyssa Berry, and Robin Murray
Special-status plant, wildlife, and potential jurisdictional wetlands	Rare plant, wildlife, and potential jurisdictional wetlands surveys of the Project Site on March 23, 2009	David Kisner and Cletis England
Protocol blunt-nosed leopard lizard surveys and special-status plant and wildlife	April through July 2009 protocol surveys were conducted in areas within or south of the Kern River Flood Control Channel	Wayne Vogler, Kate Eldredge, Alyssa Berry, Cletis England, Robin Murray, Ronald Cummings, Jessica Birnbaum, David Kisner, and Andy Evans
Rare plant survey	April 6 through 9, 2010 Surveys were conducted in the vicinity of the CO_2 linear	David Kisner, Kate Eldredge, and Kelly Kephart
General biology survey	April 5 through 9, 19 through 21, and 28, 2010 Surveys were conducted along the electrical transmission linear	David Kisner, Kate Eldredge, Alyssa Berry, and Kelly Kephart
General biology survey	July 27 and 28, 2010 Surveys were conducted along the natural gas linear alignment	David Kisner, Ronald Cummings, Dave Compton, and Kelly Kephart
Blunt-nosed leopard lizard	Protocol adult and juvenile surveys along natural gas linear: 2010 – August 5 through September 15, 2010 2012 – May, June, July, and August, 2012	<u>2010</u> – David Kisner, Ronald Cummings, Dave Compton, Kate Eldredge, Jolie Henricks, Melissa Newman, Jane Donaldson, Mark Wilson, and Gilda Barboza <u>2012</u> – Level two biologists Chris Julian, David Kisner, and Kate Eldridge; and level one biologists Jamie Deutsch, Kelly Kephart, Johanna Kisner, Melissa Newman, Mike Carbiener, Mike Dempsey, and Jane Donaldson

Table 3
Biological Resources Field Surveys (Continued)

Resource	Field Surveys Completed	Conducted by URS Biologists(s)
Field Reconnaissance for Wetlands and Other Waters	December 7, 2010 Field review of the natural gas linear alignment	David Kisner, Jan Novak
Rare plant survey	March 15, 16, and 17, 2011 The survey was conducted along the natural gas linear alignment	David Kisner, Kelly Kephart, Johanna Kisner, Chris Julian, and Jamie Deutsch
Wetland delineation survey	March 15, 16, and 17, 2011 The survey was conducted along the natural gas linear alignment	David Kisner, Kelly Kephart, Johanna Kisner, Chris Julian, and Jamie Deutsch
Habitat Assessment Surveys/Hawk Winter Nest Structure Survey	February 23, 2012 The survey was conducted along the revised natural gas linear alignment, rail spur, and process water linear alignments	David Kisner and Steve Zembsch
Rare Plant Survey, Wetland Delineation and Habitat Assessment	March 27-30, 2012 The surveys evaluated the entire Action Area, including the Project Site and all Project linears, including the industrial rail spur alignment	Kelly Kephart, Jan Novak, and Jane Donaldson

Per CEC guidelines, a record search was performed for a 5-mile radius of the HECA Project Site, and within 1,000 feet of the HECA Project linears. Federally listed species with the potential to occur within 5 miles of the HECA Project Site or within 1,000 feet of the HECA Project linears were identified from the following data sources:

- USFWS species lists provided for each 7.5-minute USGS quadrangle in the biological resources Action Area (called the East Elk Hills and Tupman quadrangles).A search of all species occurrences in the California Natural Diversity Database (CNDDB) within a 5-mile radius of the Project Site and 1,000 feet of linears (CDFG, 2012a).
- The CNPS Inventory of Rare and Endangered Plants for the East Elk Hills and Tupman quadrangles (CNPS, 2009)
- 2001 Special-status plant species survey results at *Elk Hills Oil Field*, Kern County, California (Quad Knopf, 2001)
- Coles Levee Ecosystem Preserve 2007 Annual Report (Live Oak, 2008a)
- Kern Water Bank Authority Habitat Conservation Plan/Community Conservation Plan 2007 Compliance Report and Management Plan (Kern Water Bank Authority, 2008)
- Occidental Elk Hills Oil Field, Kern County, California Biological Database (2008).

Appendix C identifies all federally listed species with potential to occur within 5 miles of the Action Area. Table 4 shows all federally listed plant species with potential to occur within the Action Area. Table 5 is provided in Section 4.3, and identifies all the federally listed and special-status wildlife species with the potential to occur in the vicinity of the Action Area. These tables summarize the preferred habitats for species with potential to occur in the vicinity of the Action Area. Only species identified on Table 4 and Table 5 with a "low" or greater likelihood of occurrence in Action Area are discussed in more detail in the following sections.

4.2 FEDERALLY LISTED PLANT SPECIES

No federally listed plant species were detected during the 2008, 2009, 2010, 2011, or 2012 surveys conducted by HECA northeast of the California Aqueduct. Multi-year vegetation surveys of the Action Area within the EHOF by OEHI have not documented any federally listed plant species within the OEHI Project Site (Quad Knopf, 2001). Surveys conducted northeast of the California Aqueduct used the protocols set forth in the CDFG Protocols for Surveying and Evaluating Impacts to Special-Status Native Plant Populations and Natural Communities (CDFG, 2009). The surveys were floristic in nature, covered an extensive study area that extended 1,000 feet from the centerline of proposed linears, and reference sites from the Lokern and Lost Hills areas were visited to confirm search images for individual species, and verify that the survey timing coincided with the blooming period for the listed plant species. Figure 6, Federally Listed Plant Species Near the Action Area, shows the species that have been identified near the Action Area; however, no listed plants are within the Action Area.

4.2.1 California Jewel-Flower (*Caulanthus californicus*)

California jewel-flower (listed as federally endangered) is an annual herb that occurs primarily in Fresno, Kern, and Tulare counties. A member of the *Brassicaceae* family, it inhabits chenopod scrub, pinyon and juniper woodlands, and valley and foothill grasslands. Its habitat ranges in elevation from 70 to 1,000 meters. The blooming period is from February to May. The decline of this species is attributable to agriculture, urbanization, energy development, and grazing, and possibly by invasion of non-native plants.

Based on the location of known populations, this species is not expected to be impacted by the HECA Project or the OEHI Project.

4.2.2 Kern Mallow (*Eremalche kernensis*)

Kern mallow (listed as federally endangered) is an annual herb that occurs primarily in Kern and Tulare counties. A member of the *Malvaceae* family, it inhabits chenopod scrub and valley and foothill grasslands. Its habitat ranges in elevation from 70 to 1,000 meters. The blooming period is from March to May. The decline of this species is attributable to conversion of habitat to agricultural use, as well as grazing and oil and gas development.

Table 4
Federally Listed Plant Species with Potential to Occur within 5 Miles of the Action Area

Common Name	Scientific Name	Federal Listing Status[1]	Likelihood of Occurrence in Action Area	Habitat Associations and Flowering/ Greatest Activity Period for Area
California jewel-flower	*Caulanthus californicus*	E	Low Recorded approximately 8 miles south of the Project Site	Chenopod scrub, pinyon and juniper woodlands, valley and foothill grasslands: February-May
Kern mallow	*Eremalche kernensis*	E	Low Recorded near the northern portion of the potable water linear	Chenopod scrub, valley and foothill grasslands: March-May
San Joaquin woollythreads	*Monolopia [Lembertia] congdonii*	E	Moderate Found approximately 2 miles to east of the Project Site	Chenopod scrub, valley and foothill grasslands: February-May
Bakersfield cactus	*Opuntia basilaris* var. *treleasei*	E	Very Low Not recorded in area	Chenopod scrub, cismontane woodland, valley and foothill grassland: April-May

Notes:
[1] E= Endangered

Table 5
Federally Listed or Candidate Wildlife Species with Potential to Occur within 5 Miles of the Action Area

Common Name	Scientific Name	Federal Listing Status	Likelihood of Occurrence in Action Area	Habitat Associations
Reptiles				
Blunt-nosed leopard lizard	*Gambelia sila*	E	Present Observed in 2008 within 1 mile south of the Project Site along the previously proposed CO_2 linear, and in 2010 near the northern terminus of the natural gas linear.	Inhabits sparsely vegetated alkali and desert scrub habitats in areas of low topographic relief. Preferred habitat includes semiarid grasslands, alkali flats, and washes.
Giant garter snake	*Thamnophis gigas*	T	Very Low Last recorded in 1940 within the region. Likely extirpated from Kern County.	Requires adequate water during its active season, herbaceous wetland vegetation as cover, openings in wetland vegetation for basking, and higher elevations for refuge from flood waters during the dormant season. Adapted to irrigation ditches and canals.
Birds				
Western snowy plover	*Charadrius alexandrinus nivosus*	T	Very Low Not found within 5 miles of Project Site.	Breeds above high tide-line on coastal beaches, sand spits, sparsely vegetated dunes, and beaches at creek or river mouths. Western snowy plovers that nest at inland sites are not considered part of the Pacific coast population.
Yellow-billed cuckoo	*Coccyzus americanus*	C	Very Low Poor nesting habitat; migrants may pass through area.	Inhabits open woodlands with clearings and a dense shrub layer. Often frequents woodlands near streams, rivers, or lakes.
Southwestern willow flycatcher	*Empidonax traillii extimus*	E	Very Low Poor nesting habitat; migrants may pass through area.	Breeds in dense riparian habitats along rivers, streams, or other wetlands.
Least Bell's vireo	*Vireo bellii pusillus*	E	Very Low Poor nesting habitat; migrants may pass through area.	Prefers dense, shrubby vegetation, woodlands, scrub oak, coastal chaparral, and mesquite brushlands, often near water in arid regions.

Table 5
Federally Listed or Candidate Wildlife Species with Potential to Occur within 5 Miles of the Action Area (Continued)

Common Name	Scientific Name	Federal Listing Status	Likelihood of Occurrence in Action Area	Habitat Associations
Mammals				
Buena Vista Lake shrew	*Sorex ornatus relictus*	E	Low Habitats in the Action Area are not suitable for this species; no freshwater marsh wetlands or riparian habitats with dense cover in the Action Area.	Inhabits valley freshwater marsh with well-developed ground layer of dead branches, leaf litter, downed logs, exposed cottonwood and willow roots, and high soil moisture.
Giant kangaroo rat	*Dipodomys ingens*	E	High Observed approximately 1 mile south of the Project Site in 1990. Per February 2012 communication with CDFG, this species is expected on the southern side of California Aqueduct, but not likely to occur east of the Aqueduct.	Saltbush scrub and sink scrub communities in the Tulare Lake Basin of the southern San Joaquin Valley. Requires soft, friable soils, which escape seasonal flooding where it will dig burrows in elevated soil mounds at the base of shrubs.
Tipton kangaroo rat	*Dipodomys nitratoides nitratoides*	E	High Previously documented within 1 mile of the Project Site and within the Action Area for the linear Project components.	Valley sink scrub and valley saltbush scrub in the Tulare basin. Sparse top moderate shrub cover is associated with high-density populations. Terrain not subject to flooding is an important factor for permanent occupancy.
San Joaquin kit fox	*Vulpes macrotis mutica*	E	Present Active dens observed in vicinity of CO_2 linear in 2008 and potential tracks/sign observed in KRFCC in 2009.	Chenopod scrub, grasslands, and other habitats. Sometimes forages in agricultural areas.

Notes:
E Federal Endangered T Federal Threatened C Federal Candidate

Based on the location of known populations, this species may be found near the process water pipeline. However, the process water pipeline would be installed within an existing dirt road, and therefore the Kern mallow is not expected to be impacted by the HECA Project or the OEHI Project.

4.2.3 San Joaquin Woollythreads (*Monolopia [Lembertia] congdonii*)

San Joaquin woollythreads (listed as federally endangered) is an annual herb that occurs primarily in Fresno, Kern, and Kings Counties. A member of the *Asteraceae* family, it inhabits chenopod scrub as well as valley and foothill grasslands. Its habitat ranges in elevation from 60 to 800 meters. The blooming period is from February to May. The decline of this species is attributable to agriculture, urbanization, oil and gas development, grazing, trampling, and vehicles.

Based on the location of known populations, this species is not expected to be impacted by the HECA Project or the OEHI Project.

4.3 FEDERALLY LISTED REPTILE SPECIES

Federally listed reptile species with the potential to occur within the Action Area are described below and shown in Table 5. Species with no suitable habitat, and those that have been extirpated in the vicinity of the Action Area, are not discussed further in this document.

4.3.1 Blunt-Nosed Leopard Lizard *(Gambelia sila)*

The blunt-nosed leopard lizard is listed as federally endangered. It inhabits sparsely vegetated alkali and desert scrub habitats. Blunt-nosed leopard lizards are carnivorous. They forage opportunistically on the ground, catching grasshoppers, cicadas, and small lizards, including smaller leopard lizards. They commonly hunt by slowly stalking prey, then rapidly dashing in to capture it.

Leopard lizards typically find shelter by using mammal burrows, shrubs, or structures such as fence posts. Females can create nests by altering unused mammal burrows to form a closed chamber below the soil surface (Tollestrup, 1983). Leopard lizard habitat is characterized by sparsely vegetated scrub and grassland habitats in flat areas. Blunt-nosed leopard lizards hibernate during the winter and are active from late March to late June or July. Metabolic rates and activity are regulated by ambient temperatures. They mate from late April through May and the females usually lay eggs between May and June. The usual clutch size is three eggs, but a clutch can range from two to six. Females usually produce one clutch per year, although occasionally a second is produced. The incubation period is approximately 57 days. Females may breed during their first spring, but males may not breed until they are large enough to secure a territory (Tollestrup, 1982; 1983).

Blunt-nosed leopard lizard populations are located in scattered sites in the San Joaquin Valley and adjacent foothills and are found between elevations of 100 to 2,400 feet (Stebbins, 2003) on alkali flats, large washes, arroyos, canyons, and low foothills. The decline of this species is primarily attributable to conversion of habitat to agricultural land. Other potential factors in the decline of blunt-nosed leopard lizard populations include predation by ravens.

No blunt-nosed leopard lizards have been observed on the Project Site or within the KRFCC area, portions of which were surveyed in 2008. Figure 7, Blunt-Nosed Leopard Lizard Occurrences Near the Action Area, shows known current blunt-nosed leopard lizard observations and the current understanding of occupied habitat within the Action Area; Figure 7 summarizes the information collected on the OEHI portion of the project over the course of 17 years of data collected for annual reporting requirements. In addition to CNDDB records, blunt-nosed leopard lizards have been observed by URS biologists at several other locations in the vicinity of the proposed HECA Project:

- In August 2008, 20 juvenile blunt-nosed leopard lizards were seen in the course of 1 day on the southwest side of the California Aqueduct, west of the proposed CO_2 pipeline.
- In 2009, a male blunt-nosed leopard lizard was seen approximately 0.2 mile west of the town of Tupman north of the east-west access road.
- In late August 2010, one blunt-nosed leopard lizard was observed approximately 0.4 mile east of the Buttonwillow Ecological Reserve.

The CO_2 pipeline south of the California Aqueduct will be constructed within habitats assumed to be used by blunt-nosed leopard lizard based on known occurrences in the vicinity. Annual surveys of the northern flank of Elk Hills for blunt-nosed leopard lizards have detected this species sporadically since 2000 (OEHI, 2012; Figure 7). Most of the recently documented occurrences of blunt-nosed leopard lizard in the Elk Hills have been on the southwestern side of the hills adjacent to the Buena Vista Valley (OEHI, 2012; Stantec, 2013).

The Kern Water Bank properties are potentially suitable for blunt-nosed leopard lizard, but may not be occupied due to the abundance of grass cover and past management activities (i.e., disking or tilling and periodic flooding). The CNDDB shows records for blunt-nosed leopard lizard on the Tule Elk Reserve approximately 0.5 mile to the south of the proposed alignment from 1990.

Protocol surveys for adults and juveniles were conducted by URS in 2012. The 2012 blunt-nosed leopard lizard surveys were conducted according to the protocols described in the California Department of Fish and Game May 2004 Approved Survey Methodology for the adult blunt-nosed leopard lizard (CDFG, 2004). Five sites along the natural gas and/or rail line shown on Figure 7 were determined to have potential habitat for blunt-nosed leopard lizards. No other habitat suitable for this species is present along the linears that will be constructed by HECA. No blunt-nosed leopard lizards were detected in the Action Area during the 2012 adult and juvenile surveys conducted on the five sites shown on Figure 7.

4.3.2 Giant Garter Snake *(Thamnophis gigas)*

The giant garter snake is a federally threatened species and is one of the largest garter snakes, attaining a total length of at least 63 inches. Females tend to be slightly longer and proportionately heavier than males. Its diet consists of small fish, tadpoles, and frogs. Adequate water during the early spring through mid-autumn to provide food and cover is an essential habitat requirement. During its active season, wetland vegetation such as cattails and bulrushes provide essential cover and foraging habitat; openings alongside waterways facilitate basking. During the dormant season of winter, giant garter snakes require higher elevation uplands for cover and safety from flood water. Throughout the dormant season, giant garter snakes inhabit small mammal burrows that lie above flood elevations. Giant garter snakes breed through March and April, and females give birth to live young from late July through early September. Brood size ranges from 10 to 46 young, with an average brood size of 23. Young immediately disperse into dense cover and absorb their yolk sacs, after which they begin foraging independently. Sexual maturity is reached at an average age of 3 years for males and 5 years for females (Stebbins, 2003).

The giant garter snake lives in agricultural wetlands and other waterways such as irrigation and drainage canals, sloughs, ponds, small lakes, low gradient streams, and adjacent uplands in the Central Valley. Due to the direct loss of natural habitat, the giant garter snake relies heavily on rice fields in the Sacramento Valley, but also uses managed marsh areas in Federal National Wildlife Refuges and State Wildlife Areas. Giant garter snakes are usually absent from larger rivers due to a dearth of suitable habitat and emergent vegetative cover, and from areas with sand, gravel, or rock substrates. Only a few recent sightings of giant garter snakes in the San Joaquin Valley are documented in the CNDDB (CDFG, 2012a).

The species is now apparently extirpated or very rare in most of its former range in the southern San Joaquin Valley. Surveys in the 1970s and 1980s yielded some previously unknown localities and several cases of extirpation or at least severe population declines (USFWS, 1993). The area of occupancy, number of sub-populations, and population size are probably continuing to decline, but the rate of decline is unknown. The decline of this species is primarily attributable to loss and degradation of habitat (USFWS, 1999a). Activities that may degrade habitat include maintenance of flood control and agricultural waterways, weed abatement, rodent control, discharge of contaminants into wetlands and waterways, and overgrazing in wetland or streamside habitats. Factors that may be significant in some areas include predation by and competition with introduced species, parasitism, and road kills (USFWS, 1999a). USFWS (1993) listed threats as habitat loss, flooding (in rice production areas), pollutants, vehicular traffic, livestock grazing, and introduced predators such as house cats and bullfrogs.

No giant garter snakes were observed during the 2008, 2009, 2010, 2011, or 2012 surveys. In addition, based on input from USFWS and CDFG, this species is presumed to be extirpated from the Action Area.

4.4 FEDERALLY LISTED MAMMAL SPECIES

No small mammal trapping was conducted to the northeast of the California Aqueduct during the 2008, 2009, 2010, 2011, or 2012 assessment surveys. Information on the small mammals in the Action Area was gained from other ongoing surveys mentioned above. There is evidence of small mammal activity, including burrows of various sizes, gopher mounds, scat, and tracks within areas of natural vegetation. Potential signs of listed mammals, such as Tipton kangaroo rat (*Dipodomys nitratoides nitratoides)* were seen within the Kern Water Bank properties.

Listed mammal activity on the OEHI property has been monitored over the course of 17 years as part of the ongoing biological monitoring (OEHI, 2012).

4.4.1 Buena Vista Lake Shrew (*Sorex ornatus relictus*)

The Buena Vista Lake shrew is a federally endangered species that inhabits the marshes of the southern San Joaquin Valley. It is a subspecies of the ornate shrew, *S. ornatus ornatus*. Shrews primarily feed on invertebrates, particularly insects. The Buena Vista Lake shrew does not cache food in burrows, and must forage frequently throughout the day and night to maintain its rapid metabolic rate. During the hottest months, activity is mostly confined to cooler periods of the day and night. The reproductive period stretches from late February through September and early October. Females of this species may have from one to eight offspring per litter, though four to six is typical. Nothing is known about the reproductive and mating system of the Buena Vista Lake shrew, but the breeding season may begin in autumn and end with the onset of the dry season in May or June (Williams and Kilburn, 1992).

The Buena Vista Lake shrew formerly occupied the marshlands of the San Joaquin Valley and the Tulare Basin. Its range has diminished due to the loss of lakes and sloughs in the area. It has been recorded from the Kern Lake Preserve area and the Kern National Wildlife Refuge. It occurred in the wetland habitats around the original historic Buena Vista, Tulare, and Kern lakes, and along streams and sloughs throughout the lake basins. Recent captures of shrews at the Kern Lake Preserve were made within a meter of the water line of Gator Pond in the shaded understory of cottonwood-willow riparian habitat, in dense stands of cattails (*Typha* spp.) and bulrushes (*Scirpus* spp.), or occasionally in dense patches of alkali heath (*Frankenia grandifolia*) (Maldonado, 1992; Maldonado et al., 1998). A partial list of plants found at many capture sites is: Fremont cottonwood (*Populus fremontii*), willow (*Salix* spp.), pickleweed (*Salicornia* sp.), alkali heath (*Frankenia grandifolia*), wild-rye (*Elymus* sp.), and Baltic rush (*Juncus balticus*). Many capture sites contain a well-developed ground layer of dead branches, leaf litter, downed logs, exposed cottonwood and willow roots, and high soil moisture. Its current distribution is unknown but is likely to be very restricted due to the loss of habitat. The decline of this species is attributable to loss of habitat due to agricultural conversion (Williams and Kilburn, 1992). Due to lack of study, information about the home range size, breeding territory size, and population densities of the shrew is lacking.

No Buena Vista Lake shrews were seen during the 2008, 2009, 2010, 2011, or 2012 surveys. Established riparian habitat that is potentially suitable for this species is approximately 1 mile southeast of the HECA Project Site; agricultural waterways which may offer marginal habitat are common within the larger Project Area. There have been observations of this species approximately 3.5 miles southeast of the HECA Project Site in 1999 (CDFG, 2012b). This species is not expected to occur in the HECA Project Site or along any of the linears; however, based on a recent observation of this species in the KRFCC, the USFWS noted during the October 17, 2012, site visit that this species might occur in the vicinity of the process water pipeline, where it is located adjacent to canals or drainage features. These canals or drainage features may offer periodic and temporary dispersal corridors between larger patches of suitable habitat; long-term occupation of the canals and drainage features is not expected due to the lack of sustained habitat, prey, and water levels.

No Buena Vista Lake shrews have been documented in the OEHI Project Site, and no shrews are expected due to the arid habitat and lack of canals, wetlands, or other water features. The proposed CO_2 Pipeline would avoid potential disturbance of the KRFCC by constructing this segment using HDD installation.

4.4.2 Giant Kangaroo Rat *(Dipodomys ingens)*

Giant kangaroo rats are nocturnal rodents that are federally endangered and occur in scattered colonies along the western side of the San Joaquin Valley. They are typically found on fine, sandy loam soils with sparse annual grass and forb vegetation, and marginally found in low-density alkali desert scrub. Their diet primarily consists of seeds, which are cached in burrows (Shaw, 1934) and green vegetation in spring. Level terrain and sandy loam soils are needed for burrowing. Optimal cover consists of areas with almost no shrub overstory, and very few physiographic variations (Grinnell, 1932; Shaw, 1934; Hawbecker, 1951).

Breeding season lasts from January to May, peaking in early spring. Litter size ranges from four to six individuals and young are born and reared in the burrows. Predators include kit foxes, badgers, coyotes, barn owls, rattlesnakes, and gopher snakes. *D. ingens* currently occupies about 2 percent of its former range (CDFG, 1980). The decline of this species is attributable to loss of habitat to cultivation and overgrazing, and the use of rodenticides (CDFG, 1980).

No giant kangaroo rats or precincts were seen during the 2008, 2009, 2010, 2011, or 2012 surveys. Figure 8, Giant Kangaroo Rat Occurrences Near the Action Area, shows all known current giant kangaroo rat observations and the current understanding of occupied habitat within the Action Area. Based on annual monitoring conducted by OEHI, it is assumed that this species may occur within the OEHI Project Site along the CO_2 pipeline, but is not expected to occur farther south within the CO_2 EOR Processing Facility area or satellite development areas.

4.4.3 Tipton Kangaroo Rat (*Dipodomys nitratoides nitratoides*)

The Tipton kangaroo rat is a federally endangered species typically found in arid-land vegetative communities with flat or gently sloping terrain located within the floor of the Tulare Basin in the southern San Joaquin Valley. Tipton kangaroo rats generally occupy grassland with scattered shrubs and desert-shrub associations on friable soils. Burrows are commonly located in slightly elevated earth, canal embankments, and bases of shrubs and fences where mobile soils gather above the level of surrounding terrain. Soft soils generally support higher densities of Tipton kangaroo rats than other soil types (Williams and Kilburn, 1992). Tipton kangaroo rats require terrain that is not subject to flooding to support a sustainable population. Reproduction occurs in the winter months, with most females giving birth to only two young.

The historical geographic range of Tipton kangaroo rats encompassed over 1.7 million acres of arid land. Their populations occupied the valley floor of the Tulare Basin throughout level or nearly level terrain. Current occurrences are restricted to scattered, isolated areas. In the southern San Joaquin Valley this includes the Kern National Wildlife Refuge, Delano, and other scattered areas within Kern County. Agricultural and residential development and the widespread use of rodenticides are principally responsible for the decline of the species (Williams and Kilburn, 1992).

No Tipton kangaroo rats were seen during the 2008, 2009, 2010, 2011, or 2012 surveys. However, signs of kangaroo rats (burrows, tail drag, foot prints, and scat) were observed within areas with suitable habitat along portions of the natural gas pipeline alignment. A local small mammal expert noted that 2010 had the highest capture rate for Tipton kangaroo rats ever recorded for the area (Warrick, 2010). Tipton kangaroo rats are assumed to be present throughout the Action Area northeast of the aqueduct in areas where suitable habitat is present. Figure 9, Tipton Kangaroo Rat Occurrences Near the Action Area, shows the locations of known Tipton kangaroo rat. Many of these records are very broad and non-specific and/or older than 20 years, but Tipton kangaroo rats could be present throughout the Action Area in areas with suitable habitat.

4.4.4 San Joaquin Kit Fox (*Vulpes macrotis mutica*)

The San Joaquin kit fox is federally listed as an endangered species (USFWS, 1999b). It historically ranged throughout the San Joaquin Valley from Contra Costa County to northern Santa Barbara County. San Joaquin kit foxes remain widely dispersed but have greatly reduced numbers and isolated populations (Williams and Kilburn, 1992). San Joaquin kit foxes primarily live in grassland and to a lesser extent, shrub and agricultural habitats. They predominantly eat rodents, ground squirrels, rabbits, hares, and ground-nesting birds. The pups are born in late winter and early spring, and the male provides most of the food for the female while she is nursing. Kit foxes change dens frequently, often enlarging existing ground squirrel burrows to create new dens. Predation or competitive exclusion of kit foxes may occur in the presence of coyotes, introduced red foxes, domestic dogs, bobcats, and large raptors. Human threats to the San Joaquin kit fox include destruction of habitat, habitat degradation, predator and pest control programs, and accidents caused by proximity to humans such as electrocution, road-kills, and suffocation from accidental burial in dens (Williams and Kilburn, 1992). Finally, natural factors such as drought, flooding, and rabies cause a significant percent of kit fox deaths.

San Joaquin kit foxes could occur throughout the region of the Project Site and linears; however, based on observations of dens, scat, and burrows during surveys from 2008 through 2010, the Elk Hills area southwest of the Kern River Flood Control Channel is likely to be the most intensively used area within the Action Area (Figure 10, San Joaquin Kit Fox Occurrences Near the Action Area). Very few kit foxes have been recorded northeast of the Kern River Flood Control Channel near the Project Site and linears in the last 20 years, based on CNDDB records (2012a). No active kit fox dens were seen in 2008, 2009, 2010, 2011, or 2012 in areas northeast of the KRFCC; numerous historic burrows were evident along the proposed natural gas pipeline alignment, but none of the burrows showed sign of recent use.

The Kern Water Bank properties have the potential to contain kit fox habitat, because they are open scrub with friable soils for digging burrows, and support a prey base of rodents. However, no burrows were seen that appeared suitable for kit fox, and coyotes were seen in this area periodically; coyotes tend to exclude kit fox from the immediate vicinity.

San Joaquin kit fox have been regularly documented in the northern portion of the OEHI Project Site along the proposed CO_2 pipeline and the CO_2 EOR Processing Facility during the course of the 17 years of monitoring in this area (OEHI, 2012). There have been no documented kit fox in the area surrounding the three satellites.

5.0 EFFECTS ANALYSIS

This section evaluates the potential effects of the proposed HECA Project and OEHI Project on federally listed species. The effects analysis addresses the federally listed plant and wildlife species described in the previous sections. Potential effects are evaluated based on the area of direct habitat disturbance (direct effect) and additional indirect effects, as defined below. This section also addresses potential cumulative effects.

5.1 DEFINITION OF EFFECTS

Potential effects of the proposed action are characterized in this section using the following terms:

- Direct effects are the immediate effects of a proposed action on a federally listed species or its habitat.
- Indirect effects are defined as "those effects that are caused by or would result from the proposed action and are later in time, but are still reasonably certain to occur" (USFWS/NMFS, 1998).
- Cumulative effects are defined as "those effects of future State or private activities, not involving Federal activities, that are reasonably certain to occur within the action area of the Federal action subject to consultation" (USFWS, 1998).

Potential effects are also characterized as either temporary or permanent in duration. Effects that would be restored to pre-construction elevations within 1 calendar year, and are not subject to active project-related disturbance are identified as temporary effects; effects that cannot be restored to pre-construction conditions within 1 calendar year or are subject to active project-related disturbance are characterized as permanent.

5.2 HABITAT DISTURBANCE

This section summarizes potential habitat disturbance that would be associated with the HECA Project and the OEHI Project. This summary focuses on habitats that are potentially used by federally listed species. Potential habitat disturbance would include permanent conversion to other habitat types (e.g., developed) and temporary removal of habitats during construction.

The HECA Project and OEHI Project would affect habitat that supports or has the potential to support federally listed wildlife species. The estimated direct impacts to habitats potentially used by federally listed species are quantified in Table 6. Construction of the natural gas and CO_2 pipelines would directly impact Natural/Ruderal (Allscale Scrub) habitat that is known to support breeding, foraging, and dispersal of federally listed species listed in the direct effects discussion below. The proposed OEHI CO_2 EOR facilities would affect habitat that has moderate multispecies habitat value in the draft Elk Hills HCP (HCP Section 5, Figure 5.1) (Stantec, 2012a). Therefore, Table 6 includes the OEHI EOR impacts under the Natural/Ruderal habitat category, based on the Demonstration Period project information provided by OEHI (Stantec, 2012c). Habitats within the HECA Project

Table 6
Area of Direct Effects to Habitats and Existing Land Use Types within the Action Area

	Project Site		Construction Staging Area		Railroad Spur		Railroad Spur Laydown Yard		Natural Gas Pipeline		Process Water Supply Pipeline and BVWSD Well Field		Transmission Line/PG&E Switching Station/ Potable Water Pipeline		OEHI CO_2 Pipeline[2]		OEHI EOR Facilities[2]		Total	
Habitat/ Land Use Types[1]	**Temporary**	**Permanent**	**Temporary**	**Permanent**	**Temporary**	**Permanent**	**Temporary**	**Permanent**	**Temporary**	**Permanent**	**Temporary**	**Permanent**	**Temporary**	**Permanent**	**Temporary**	**Permanent**	**Temporary**	**Permanent**	**Temporary**	**Permanent**
Alfalfa	–	118.0	59.8	–	1.7	5.3	2.0	–	3.4	–	5.9	1.15	2.8	3.29	–	–	–	–	75.6	127.74
Other Row Crop	–	317.3	20.0	–	3.5	16.2	–	–	9.4	0.23	1.7	–	–	–	–	–	–	–	34.6	333.73
Orchards	–	–	–	–	1.1	4.5	–	–	0.6	–	2	–	0.7	0.01	–	–	–	–	4.4	4.51
Natural/ Ruderal	–	–	–	–	–	–	–	–	3.7	–	–	–	–	–	28.89	0.11	–	63.79	32.59	63.90
Developed/ Disturbed	–	17.7	11.2	–	3.3	12.4	1.0	–	30.1	–	79.5	–	3.7	0.85	–	–	–	–	128.8	30.95
Total	**–**	**453.0**	**91.0**	**–**	**9.6**	**38.4**	**3.0**	**–**	**47.2[3]**	**0.23**	**89.1**	**1.15[4]**	**7.2**	**4.15**	**28.89**	**0.11**	–	**63.79**	**275.99**	**560.83**

Notes:

[1] Areas not designated as crop land or Natural/Ruderal land have been classified as Developed/Disturbed.
[2] Source: DOE Data Request – Initial Injection Phase Project Description (Stantec, 2012c).
[3] The area of temporary habitat disturbance along the portion of the natural gas linear that follows the railroad spur from the Project Site to the interconnection of the railroad with the existing San Joaquin Valley Railroad line is included in the temporary effects for the railroad spur.
[4] The area that would be permanently affected is based on five wells that would occupy approximately 100 feet by 100 feet each. The exact well locations are not known, but the entire area is assumed to be within alfalfa fields.

CO_2 = carbon dioxide
EOR = enhanced oil recovery
OEHI = Occidental of Elk Hills, Incorporated
PG&E = Pacific Gas and Electric Company

Site, process water pipeline route, and electrical transmission line route are not likely to be used by blunt-nosed leopard lizards or kangaroo rats; however, these areas may offer limited foraging opportunities and dispersal corridors for the San Joaquin kit fox.

One of the constraints associated with the OEHI Project EOR facilities is the presence of existing conservation lands, including the CDFG Lokern Ecological Reserve and other areas. The HECA and OEHI project linears have been aligned to avoid impacts to existing conservation areas and biologically significant areas.

5.2.1 Direct Effects

Direct effects are identified as either permanent or temporary, depending on the duration of disturbance. Permanent disturbance is defined as a disturbance of the substrate that results in paving or development of the surface that will not eventually revert back to natural habitat with value for plants and wildlife. A temporary disturbance implies a physical impact to an area for less than one season, and that the value of the habitat can typically be reestablished within 2 years of disturbance.

Natural habitat types within the Action Area include Allscale Scrub, which includes small patches of Allscale, Riparian Scrub, and open areas dominated by non-native grasses and fiddleneck (*Amsinckia* sp.) (Sawyer, Keeler-Wolf, and Evens, 2009). This document refers to this habitat as Natural/Ruderal habitat. The HECA Project would temporarily and/or permanently remove the following habitats:

- Agricultural lands
- Natural/Ruderal Habitat (Allscale Scrub)

Temporary and permanent direct effects to agricultural lands are not likely to adversely affect blunt-nosed leopard lizards or Tipton or giant kangaroo rats. However, agricultural lands are occasionally used by San Joaquin kit fox for movement and migration. The HECA Project would permanently remove agricultural lands that are cultivated for alfalfa, cotton, and onions. Permanent development of 435 acres of cultivated lands within the HECA Project Site, the 1.15-acre water wells, and the 4-acre PG&E switching station is assumed to have a minimal direct effect on the San Joaquin kit fox population in the region, due to the current land use practices and the distance (approximately 1 mile) from more suitable habitats in the Elk Hills area.

Construction of portions of the CO_2 and natural gas pipelines would affect Allscale Scrub that is potentially used by blunt-nosed leopard lizard, giant kangaroo rat, and San Joaquin kit fox. Approximately 3.7 acres of Natural/Ruderal habitat would be temporarily disturbed during construction of the natural gas pipeline. The OEHI Project would permanently impact 63.79 acres and temporarily impact 28.89 acres within the EHOF (Stantec, 2012a; Stantec, 2012b; and Stantec, 2012c). All of the OEHI temporary effects would be associated with the CO_2 pipeline construction, which would permanently impact approximately 0.11 acre. However, a significant portion of the EOR facilities will be located in areas of the EHOF where disturbance has already occurred, and OEHI will design project components to use existing disturbed acreage to the maximum extent feasible.

5.2.2 Indirect Effects

The proposed action could indirectly affect adjacent habitats for listed species. Indirect effects could include increased emissions of air pollutants, nitrogen deposition, erosion, dust from construction vehicles, and introduction of invasive or noxious species.

The increased emissions from the construction activities are not expected to significantly affect agricultural or natural habitats. The emissions from the construction vehicles would occur over the course of the 42-month construction schedule and are not anticipated to significantly impact the region's air quality or the vegetation and wildlife in the Action Area. The emissions from the HECA Project include emissions from the plant's heat recovery steam generator stack and cooling tower facilities. The emissions will meet regional air quality standards, and will not result in an impact to the surrounding federally listed plants or wildlife.

Erosion will be controlled by implementing the Storm Water Pollution Prevention Plan and an erosion protection plan.

Dust associated with construction will be controlled by wetting dry, friable soils in the construction area. Periodic wetting of the access routes may also prove necessary depending on the wind and weather patterns.

Ground-disturbing construction activities could potentially introduce or facilitate the establishment of noxious or invasive species. HECA LLC will implement the conservation measures described in Section 2.3 to minimize this impact. OEHI will continue to implement the terms and conditions of the 1995 USFWS Biological Opinion and the 1997 CDFG MOU that are intended to minimize potential effects on listed species.

5.3 FEDERALLY LISTED PLANT SPECIES

No federally listed plant species were detected during the 2008, 2009, 2010, 2011, or 2012 plant surveys, and no federally listed plants are expected to be directly affected by the HECA Project or OEHI Project. The federally listed California jewel-flower, Kern mallow, and San Joaquin woollythreads are known to occur in the region, but are absent from the Action Area. Surveys along the natural gas pipeline are currently being conducted by HECA; however, based on site visits and existing data, no federally listed plants are expected in this area. If any federally listed plant species are found along the natural gas pipeline, the USFWS will be informed immediately and the population will be avoided by rerouting the pipeline, and/or reducing the construction corridor (see conservation measure BIO-3). Additional information will be provided to USFWS following the completion of the surveys.

5.4 FEDERALLY LISTED REPTILE SPECIES

5.4.1 Blunt-Nosed Leopard Lizard

Blunt-nosed leopard lizards were detected within the Elk Hills portion of the Action Area during the 2008 and 2009 surveys. One individual was also detected east of the Buttonwillow Ecological Reserve during the 2010 surveys of the natural gas linear; no blunt-nosed leopard lizards were detected during protocol adult and juvenile surveys completed in 2012 within the five areas of potentially suitable habitat along the natural gas pipeline (Figure 7). Based on these survey results and the distribution of other documented occurrences, blunt-nosed leopard lizards are only expected, if at all, in the flatter portions of the CO_2 pipeline within the Elk Hills area. Potential direct and indirect effects to the blunt-nosed leopard lizard are evaluated below.

Direct Effects

Blunt-nosed leopard lizards have the potential to be directly affected by habitat removal, vehicle strikes, or entrapment in open trenches or within a burrow during the installation and maintenance of the associated pipelines. However, implementation of the proposed conservation measures would substantially minimize potential direct impacts to blunt-nosed leopard lizards during construction, operation, and maintenance. These measures would avoid take of individuals, which is prohibited under the California Fish and Game Code.

Indirect Effects

Indirect effects to blunt-nosed leopard lizards may include:

- Temporary disturbance due to noise from construction and operation activities and human presence.
- A temporary reduction in natural food sources as a result of habitat disturbance.
- Predators attracted to construction-related food or trash in the area may prey on blunt-nosed leopard lizards.
- Construction, maintenance, and operational activities associated with roads and various facilities may result in the disturbance of blunt-nosed leopard lizards.

5.4.2 Giant Garter Snake

No giant garter snakes were observed during the 2008, 2009, 2010, 2011, or 2012 surveys within the Action Area. This species is presumed to be extirpated from the Action Area.

5.5 FEDERALLY LISTED MAMMAL SPECIES

5.5.1 Buena Vista Lake Shrew

No Buena Vista Lake shrews were detected during the 2008, 2009, 2010, 2011, or 2012 surveys. This species is not expected to be present in the Action Area, based on the absence of suitable habitats and the distance from known occurrences; however, due to the unpredictable nature of this species, and to the length of the process water alignment, the USFWS requested that HECA evaluate potential for take of this species.

Direct Effects

Buena Vista Lake shrews have the potential to be directly affected by habitat removal, vehicle strikes, or entrapment in open trenches or within a burrow during the installation and maintenance of the associated pipelines. However, implementation of the proposed conservation measures would substantially minimize potential direct impacts to Buena Vista Lake shrews during construction, operation, and maintenance. These measures would avoid mortality of individuals.

Indirect Effects

Indirect effects to Buena Vista Lake shrews may include:

- Temporary disturbance due to noise from construction and operation activities and human presence.
- A temporary reduction in natural food sources as a result of habitat disturbance.
- Predators attracted to construction-related food or trash in the area may prey on Buena Vista Lake shrews.
- Construction, maintenance, and operational activities associated with roads and various facilities may result in the disturbance of Buena Vista Lake shrews.

5.5.2 Giant Kangaroo Rat

Based on range generalizations and known occurrences (refer to Figure 8), giant kangaroo rats presumably could be present along the Elk Hills portions of the CO_2 pipeline. Based on habitat preferences, more individuals would be expected within the flatter portions of the alignment, although there are only records for the steeper topographic portions of the Elk Hills area.

Direct Effects

Giant kangaroo rats have the potential to be directly affected by temporary habitat removal, vehicle strikes, or entrapment in open trenches or within a burrow during the installation and maintenance of the CO_2 pipeline. Potential direct effects will be minimized by implementation of the avoidance and minimization measures in the 1995 Biological Opinion issued by the USFWS and 1997 MOU between Oxy and the California CDFG as updated, and the HCP for the EHOF, when approved.

Indirect Effects

Indirect effects to giant kangaroo rats may include the following:

- Temporary disturbance of individual animals caused by noise associated with Project activities and human presence;

- Temporary reduction in natural food sources as a result of habitat disturbance; and

- Increased predation due to night lighting from the HECA Project Site, which would make kangaroo rats more visible to predators, and may interfere with the kangaroo rat's foraging ability.

5.5.3 Tipton Kangaroo Rat

Based on range generalizations and previously documented occurrences, Tipton kangaroo rats are presumed to be present where habitat is potentially suitable for this species, including several segments of the natural gas pipeline (Figure 9). This species is not expected to be present south of the California Aqueduct along the CO_2 pipeline route based on discussions with CDFG (Vance, 2012).

Direct Effects

Tipton kangaroo rats have the potential to be directly affected by temporary habitat removal, vehicle strikes, or entrapment in open trenches or burrows during the installation and maintenance of the natural gas pipeline. Implementation of the trapping, relocation, worker education program, and speed limits would minimize these potential direct effects. Direct impacts to Tipton kangaroo rats are not expected to affect more than 10 individuals over the life of the HECA Project.

Indirect Effects

Indirect effects to Tipton kangaroo rats may include the following:

- Temporary disturbance from noise associated with construction and operation activities and human presence;
- Reduced availability of natural food sources as a result of habitat disturbance; and
- Increased predation because night lighting from the HECA Project may make the Tipton kangaroo rats more visible to predators, and may interfere with the kangaroo rat's foraging ability.

5.5.4 San Joaquin Kit Fox

Potential direct and indirect effects to San Joaquin kit foxes are evaluated in this section. San Joaquin kit fox are known to occur in the Elk Hills area about 1 mile south of the HECA Project Site (Figure 10). This species has also been occasionally observed in agricultural areas in the HECA Project Site and the Controlled Area, as well as the construction areas of the various linear facilities.

Direct Effects

Construction of the HECA Project and OEHI Project could directly affect San Joaquin kit foxes in the region. Direct effects could include temporary and permanent habitat loss, vehicle strikes, and entrapment in open trenches or within burrows during the installation and maintenance of the natural gas, process water, and CO_2 pipelines. In addition, portions of the HECA Project would be within the Western Kern County Core recovery area identified in the Recovery Plan for Upland Species of the San Joaquin Valley (USFWS, 1998).

The USFWS Recovery Plan identifies several kit fox recovery areas in the Action Area, including:

- Western Kern County Core
- Antelope Plain/Semitropic Kern Satellite
- Urban Bakersfield Satellite

The HECA Project Site is adjacent to the northeastern edge of the Western Kern County Core recovery area. In addition, portions of the proposed CO_2 linear, electrical transmission lines, and process water pipeline are within this area (Figure 11 and Table 7). The HECA Project would temporarily disturb or remove habitats in these areas that are already degraded by existing activities (i.e., dirt roads, active agriculture, and canals), and are not likely to provide habitat for breeding or denning kit foxes. These areas are also not high-quality habitat for kangaroo rats, because kit foxes appear to be strongly linked ecologically to kangaroo rats (Cypher, 2006).

Table 7
Overlap of Project Components and the San Joaquin Kit Fox Western Kern County Core Recovery Area

HECA Project Component	Area (Acres) within the Western Kern County Core Recovery Area
HECA Project Site	7.0[1]
Carbon Dioxide Pipeline	28.9
Process Water Pipeline	42.2[2]
Total	**78.2**

Notes:
[1] Acreage is actively farmed and is poor habitat for the San Joaquin kit fox.
[2] Acreage is included in the HECA Project Site area, is actively farmed, and is poor habitat for the San Joaquin kit fox.

The HECA Project Site and other permanent project components are actively farmed and are unlikely to provide foraging or movement habitat for San Joaquin kit fox. Although the HECA Project Site is approximately 1 mile from the margin of the Elk Hills area, the likelihood that kit fox would be present in this area is reduced by the presence of the California Aqueduct, roads, and other existing physical barriers, in addition to human activity associated with cultivated fields. Therefore, permanent loss of 435 acres at the HECA Project Site, 26 acres for the new railroad spur, 0.23 acre for the new natural gas pipeline, 1.15 acre for the BVWSD well field, and 4 acres at the PG&E switching station would have a minimal direct effect on San Joaquin kit fox in the region, because this species is not likely to regularly use the affected fields.

Approximately half of the Western Kern County Core recovery area that would be impacted by the CO_2 pipeline is high-quality habitat potentially used for denning, foraging, and dispersal of San Joaquin kit fox. The other half is less suitable for denning, foraging, and dispersal due to the steep topography of the Elk Hills and the level of existing disturbance to the area. The portion of the Western Kern County Core recovery area impacted by the process water pipeline is generally poor habitat for denning, foraging, and dispersal due to the level of disturbance (i.e., graded dirt roads, agricultural canals, and actively farmed lands) and proximity to other types of human disturbance (i.e., dumping, target shooting, and spraying).

Traffic associated with construction and operations would pass through portions of habitat for the Western Kern County Core recovery area, the Antelope Plain/Semitropic/Kern and Urban Bakersfield Satellite recovery area, and potential habitat linkages along I-5 and State Route 46 (Figure 11). The existing average daily traffic (ADT) and the HECA Project-related increase to the ADT were evaluated for the road segments inside of the San Joaquin kit fox recovery areas (Table 8). Most of the increases in traffic during construction were minimal, with the exception of the increase in traffic on Tupman Road and Stockdale Highway. Operation-related traffic includes the workforce for the HECA Project, the delivery of coal and petcoke, and shipping of some products. Petcoke deliveries are included in the operation-related traffic impacts because the trucks delivering the fuel pass through portions of the Antelope Plain/Semitropic/Kern and Urban Bakersfield Satellite Population. Coal will be delivered by truck or by rail; therefore, the potential increase in truck traffic for coal delivery is addressed in the mortality calculations because it represents the most conservative estimate of potential impacts.

The existing mortality of San Joaquin kit fox in the western Bakersfield area was determined through the 6-year study *Urban Roads and the Endangered San Joaquin Kit Fox* by Bjurlin, Cypher, Wingert, and Van Horn Job (2005). Existing, construction, and operations traffic levels were determined using Section 5.10 of the Amended AFC (Hydrogen Energy California, 2012) and Caltrans traffic estimates. Based on known mortality rates and traffic levels, the HECA Project-related mortality of San Joaquin kit fox is estimated at approximately 39 foxes over the course of 25 years (Table 9). This is a conservatively high estimate because the time of day during which the increased traffic would be on the road was not considered in the estimate; most HECA Project-related traffic would be on the roads during daylight hours when kit fox are less likely to be present. Kit foxes tend to travel during the evenings, at night, or near dawn.

The combination of potential traffic-related impacts summarized above and other potential habitat impacts to San Joaquin kit fox identified in this section is estimated to affect fewer than 39 individuals over the 25-year life of the HECA Project.

Indirect Effects

San Joaquin kit foxes inhabiting the Action Area and surrounding vicinity are likely to be subject to indirect effects, including:

- The temporary and permanent loss of kit fox foraging, pupping, and movement corridor habitat.
- Temporary harassment from noise associated with construction and operation activities and human presence.
- A temporary reduction in natural food sources as a result of habitat disturbance.
- Construction, maintenance, and operational activities associated with roads and various facilities may result in the disturbance of nearby San Joaquin kit foxes.
- Night lighting from the HECA Project Site may make kit foxes more visible to predators, and may interfere with the kit fox's foraging ability.

Table 8
Existing and HECA Project-Related Traffic Estimates within the San Joaquin Kit Fox Recovery Area

Roadway	Current ADT[1]	Construction		Operations[2]		Product Deliveries[3]	
		Current + Project ADT	Project Increase	Current + Project ADT	Project Increase	Current + Project ADT	Project Increase
I-5 (north of SR 46)	30,500	30,759	0.8%	30,876	1.2%	30,702	0.7%
I-5 (south of SR 119)	30,000	30,396	1.3%	30,416	1.4%	30,226	0.8%
Tupman Road (Tupman Town)[4]	490	1,474	200.8%	614	25.3%	490	0.0%
SR 119 (Bakersfield – east of I-5)	6,800	7,554	11.1%	6,918	1.7%	6,822	0.3%
SR 119 (Taft – west of Tupman Road)	11,800	11,924	1.1%	11,816	0.1%	11,800	0.0%
Stockdale Highway (west of I-5)[4]	2,520	3,683	46.2%	3,504	39.0%	4,321	71.5%
SR 46 (west of I-5)	10,000	10,136	1.4%	10,000	0.0%	10,000	0.0%

Notes:
1 Unless otherwise stated, ADT values were obtained from Caltrans 2010 Traffic Data.
2 HECA Project employees or by product trucks only.
3 Petcoke and coal delivery to the HECA Project Site by truck only. (Does not include employees or product trucks.)
4 Calculated from 2012 peak hour counts assuming that PM peak hour equates to 10% of ADT.

ADT = average daily traffic
SR = State Route

Table 9
HECA Project Construction and Operations Traffic Impact to San Joaquin Kit Fox

Roadways	Length (miles)	San Joaquin kit fox Recovery Area	Type	Baseline take (fox/yr/mi)	Baseline annual take (fox/year)	Project vehicles (% increase)	Project Take (fox/yr)	Cumulative Take (fox/yr)
Construction								
I-5 (north of SR 46)	14.00	Antelope Plain/ Semitropic/Kern	Satellite	0.01[1]	0.14	0.8	0.00	0.14
I-5 (south of SR 119)	5.65	Western Kern County	Core	0.03[1]	0.17	1.3	0.00	0.17
Tupman Road (Tupman Town)	5.41	Western Kern County	Core	0.14[2]	0.76	200.8	1.53	2.29
SR 119 (Bakersfield – east of I-5)	4.28	Western Kern County	Core	0.07	0.30	11.1	0.00	0.30
SR 119 (Taft – west of Tupman Road)	13.22	Western Kern County	Core	0.02[1]	0.26	1.1	0.00	0.26
Stockdale Highway (west of I-5)	5.09	Urban Bakersfield	Satellite	0.20[1]	1.02	46.2	0.47	1.49
SR 46 (west of I-5)	10.5	Antelope Plain/ Semitropic/Kern	Satellite	0.06[4]	0.63	1.4	0.01	0.64
SR 46 (west of I-5)	6.75	Link	Link	0.03[4]	0.20	1.4	0.00	0.20
SR 46 (west of I-5)	10.18	Link	Link	0.03[4]	0.30	1.4	0.00	0.30
Subtotal				0.59	3.78		2.01	5.79
Construction-related take over 3 years							**6.03**	

Table 9
HECA Project Construction and Operations Traffic Impact to San Joaquin Kit Fox

Roadways	Length (miles)	San Joaquin kit fox Recovery Area	Type	Baseline take (fox/yr/mi)	Baseline annual take (fox/year)	Project vehicles (% increase)	Project Take (fox/yr)	Cumulative Take (fox/yr)
Operations								
I-5 (north of SR 46)	14.00	Antelope Plain/ Semitropic/Kern	Satellite	0.01[1]	0.14	1.2	0.00	0.14
I-5 (south of SR 119)	5.65	Western Kern County	Core	0.03[1]	0.17	1.4	0.00	0.17
Tupman Road (Tupman Town)	5.41	Western Kern County	Core	0.14[2]	0.76	25.3	0.19	0.95
SR 119 (Bakersfield – east of I-5)	4.28	Western Kern County	Core	0.07	0.30	1.7	0.01	0.31
SR 119 (Taft – west of Tupman Road)	13.22	Western Kern County	Core	0.02[1]	0.26	0.1	0.00	0.26
Stockdale Highway (west of I-5)	5.09	Urban Bakersfield	Satellite	0.20[1]	1.02	39.0	0.40	1.42
Subtotal				0.40	2.65			3.25
Operations-related take over 25 years							**15.00**	

Table 9
HECA Project Construction and Operations Traffic Impact to San Joaquin Kit Fox (Continued)

Roadways	Length (miles)	San Joaquin kit fox Recovery Area	Type	Baseline take (fox/yr/mi)	Baseline annual take (fox/year)	Project vehicles (% increase)	Project Take (fox/yr)	Cumulative Take (fox/yr)
Product Delivery								
I-5 (north of SR 46)	14	Antelope Plain/ Semitropic/Kern	Satellite	0.01[1]	0.14	0.7	0.00	0.14
I-5 (south of SR 119)	5.65	Western Kern County	Core	0.03[1]	0.17	0.8	0.00	0.17
SR 119 (Bakersfield – east of I-5)	4.28	Western Kern County	Core	0.07	0.30	0.3	0.00	0.30
Stockdale Highway (west of I-5)	5.09	Urban Bakersfield	Satellite	0.2	1.02	71.5	0.73	1.75
Subtotal				0.31	1.63		0.73	2.36
Coal/Petcoke-related take over 25 years[4]							**18.25**	
Total Project-related take over 25 years							**39.28**	

Notes:
1 Mortality calculated from data presented in: esrp.csustan.edu/publications/pdf/esrp_urbanroad_sjkf.pdf.
2 Mortality estimated based on road type described in: esrp:csustan.edu/publications/pdf/esrp_urbanroad_sjkf.pdf.
3 Baseline take for SR 46 was estimated based on home range size from http://humboldt-dspace.calstate.edu/xmlui/bitstream/handle/2148/36/Frost.pdf?sequence=1 compared to "urban" kit fox. Link populations were assumed to be half of the satellite population.
4 Traffic-related impacts associated with operation and product deliveries would be reduced if coal is transported to the project site using the proposed rail spur.

I-5 = Interstate 5
SR = State Route

5.6 CUMULATIVE EFFECTS

Cumulative effects include the effects of future state, tribal, local, or private projects that are reasonably certain to occur in the Action Area. Future federal projects that are unrelated to the proposed action are not considered in this section because they would require separate consultation pursuant to Section 7 of the ESA (16 USC § 1536).

Only one potential non-federal proposed project occurs within the Action Area (Table 10). This project is an application for a conditional use permit to establish a 1,061-acre dairy complex, consisting of a 121-acre dairy, a 739-acre liquid waste disposal/spreading site, and a 201-acre solid waste disposal/spreading site) at Palm Ranch. Based on aerial topography, this area appears to be an existing agricultural field. Depending on the current agricultural practices at the site, conversion of habitat could potentially contribute to the loss of movement and migration habitat for the San Joaquin kit fox. If patches of alkali and scrub habitats are present within the site, habitat conversion could contribute to the loss of burrowing or denning habitat for the blunt-nosed leopard lizard, Tipton kangaroo rat, and giant kangaroo rat. Agricultural land, which may include small isolated marginal blocks of native vegetation, is marginal habitat for these species. Marginal agricultural habitats are less likely to support these species than higher quality habitats such as the Elk Hills and the Kern River floodplain. However, the loss of 1,061 acres of agricultural habitat in conjunction with the proposed action would result in substantial cumulative effects to federally listed species under USFWS jurisdiction.

Table 10 also presents potential non-federal projects that could occur within the larger vicinity of the proposed action. Most of the projects are at least 5 miles from the Action Area and are clustered around existing highway and road corridors in areas that appear to be used for agricultural, residential, commercial, and industrial purposes. Many of the projects are separated from the Action Area by I-5 and Highway 43, and by large blocks of agricultural land uses. A few of the proposed projects are located south of the Action Area either in the Elk Hills or just east of the Action Area. These projects appear to be located in areas of higher quality habitats (e.g., native vegetation) than the projects in the urban or agricultural areas; they also appear not to have significant dispersal barriers between them and the Action Area, aside from the California Aqueduct, which bisects the Action Area. Therefore, these projects could contribute to the incremental cumulative loss of habitat for the San Joaquin kit fox, blunt-nosed leopard lizard, Tipton kangaroo rat, and Giant kangaroo rat.

All of the potential non-federal projects in the vicinity of the Action Area will be required to comply with state and local regulatory requirements that also protect federally listed wildlife and plant species. Effects from these projects are expected to be mitigated through the regulatory pathways that would reduce the cumulative effects on federally listed species; however, the HECA Project and OEHI Project would contribute to a cumulatively adverse effect to the federally listed species, as identified in this biological assessment.

Table 10
Proposed Projects, Which May Lack a Federal-Nexus, Within the Vicinity of the Proposed Action

Case ID	Project Location	APN	Applicant	Case Type	Request	Acres	Use Type
Within Action Area							
10212	Adjacent to the North and West of the Project Site	159-030-06; 159-070-03; 159-130-11; 159-020-16	Dykstra Dairies/ David Albers	CUP	Conditional Use Permit to Establish a 1,061-Acre Dairy (121-Acre Dairy, 739 Acres of Liquid Waste Disposal/Spreading, and 201 Acres for Solid Waste Disposal/Spreading) (Palm Ranch)	1,061	Agriculture
At Least 5 Miles from Action Area and/or separated by major highways or agricultural blocks that reduce the potential for use or movement by federally listed species.							
9952; 9953	7626 Superior Road	104-012-15	Cooper, Michael and Cheryl/D and D	ZCC; EXCLUSION	Zoning Change/Amendment From Exclusive Agriculture (A) to Natural Resource 5 Gross Acre Minimum Lot Size [NR(5)] District; Exclusion From Agricultural Preserve	10	Industrial
10660	Southeast Corner of 7th Standard Road and Brandt Road	463-030-12	Affentranger, Franz (Pine Dairy)	CUP	Conditional Use Permit to Establish a 589.35-Acre Dairy and 1,973.28-Acre Crop Area (Pine Dairy)	2,563.63	Agriculture
12698	Tracy Avenue, Buttonwillow	103-080-44	Rio Bravo Vista/ Mcintosh and Associates	PD	Precise Development for 'La Quinta' Hotel	6.5	Commercial
12766	345 Driver Road	104-291-52	Petro Ready Mix/ Pete Pedroza	PD	Precise Development for Concrete Batch Plant	78.18	Industrial

Notes:

APN Assessor's Parcel Number
CUP Conditional Use Permit
Exclusion Exclusion from Agricultural Preserve
PD Precise Development
ZCC Zoning Change/Amendment

6.0 CONCLUSION AND DETERMINATION OF EFFECTS

This section presents determinations of the potential effects of the HECA Project and OEHI Project on federally listed species, based on the effects analysis discussed in Section 5.

6.1 FEDERALLY LISTED PLANT SPECIES

The proposed action would have **no effect** on plant species that are listed or proposed for federal listing. No federally threatened or endangered plant species or plant species proposed for listing were observed in the Action Area during 2008, 2009, 2010, 2011, or 2012 plant surveys. BIO-2 would require avoidance of any listed plant species, to the greatest extent feasible.

6.2 FEDERALLY LISTED REPTILE SPECIES

6.2.1 Blunt-Nosed Leopard Lizard

Implementation of the proposed action **may affect, and is likely to adversely affect** the blunt-nosed leopard lizard. Blunt-nosed leopard lizards have been observed along the CO_2 pipeline alignment, and would be addressed as part of the OEHI Project. Under California law, no mortality is allowed for this fully protected species. For the HECA Project, the avoidance and conservation measures BIO-4, BIO-5, BIO-6, BIO-8, BIO-15, and BIO-17 described in Section 2.3 would avoid mortality and reduce other direct effects on the blunt-nosed leopard lizard, including habitat loss or degradation. For the portions of the project within the EHOF, the avoidance measures in the 1995 Biological Opinion issued by the USFWS and 1997 MOU between Oxy and the California CDFG as updated, and the HCP for the EHOF, when approved, would avoid mortality and reduce other direct effects on the blunt-nosed leopard lizard.

The HECA Project would temporarily remove up to 3.7 acres of natural/ruderal habitat that does not appear to be occupied by the blunt-nosed leopard lizard, based on 2012 protocol surveys. The OEHI Project activities would temporarily remove up to 28.89 acres of habitat and permanently remove up to 63.90 acres of habitat potentially used by the blunt-nosed leopard lizard. Habitat compensation is proposed as described by conservation measure BIO-18 (HECA Project), and in accordance with the 1995 USFWS Biological Opinion (USFWS File # 1-1-95-F-102) and draft HCP currently under review by the USFWS (OEHI Project), which will benefit this species to offset the loss of habitat.

6.3 FEDERALLY LISTED MAMMAL SPECIES

6.3.1 Buena Vista Lake Shrew

The proposed action **may affect, but is not likely to adversely affect** the Buena Vista Lake shrew. No Buena Vista Lake shrews were observed in the Action Area during 2008, 2009, 2010, 2011, or 2012 surveys; however, this species is presumed to be present because Buena Vista Lake shrews have been previously documented in the greater biological region. Potential effects could include temporary loss of habitat during construction, and mortality of individuals caused by construction activities. The avoidance and conservation measures BIO-4, BIO-7, BIO-8, BIO-15, and BIO-16 described in Section 2.3 would substantially reduce the potential for direct effects on the Buena Vista Lake shrews. Also, habitat compensation, as described by conservation measure BIO-18, will provide additional benefits for long-term survival and recovery of the Buena Vista Lake shrew.

6.3.2 Giant Kangaroo Rat

The proposed action **may affect, and is likely to adversely affect** the giant kangaroo rat. No giant kangaroo rats were observed in the Action Area during 2008, 2009, 2010, 2011, or 2012 surveys; however, this species is presumed to be present because giant kangaroo rats have been previously documented in the Elk Hills region that would be crossed by the CO_2 pipeline. Potential effects could include temporary loss of habitat during construction, and mortality of individuals caused by construction activities. The OEHI Project actions would temporarily remove up to 28.89 acres and permanently remove approximately 63.90 acres of habitat potentially occupied by giant kangaroo rat. These 93 acres overlap entirely with the acreage already identified for blunt-nosed leopard lizard above. The avoidance and conservation measures BIO-4, BIO-7, BIO-8, BIO-15, and BIO-16 described in Section 2.3 would substantially reduce the potential for direct effects on the giant kangaroo rats for the portions of the CO_2 pipeline not within the EHOF. For the portions of the pipeline within the EHOF, the avoidance measures in the 1995 Biological Opinion issued by the USFWS and 1997 MOU between Oxy and the California CDFG as updated, and the HCP for the EHOF, when approved, would substantially reduce the potential for direct effects on the giant kangaroo rats. Also, habitat compensation, as described by conservation measure BIO-18 (HECA Project), and the 1995 USFWS Biological Opinion (USFWS File # 1-1-95-F-102) and draft HCP currently under review by the USFWS (OEHI Project), will provide additional benefits for long-term survival and recovery of the giant kangaroo rat.

6.3.3 Tipton Kangaroo Rat

The proposed action **may affect, and is likely to adversely affect** the Tipton kangaroo rat. No Tipton kangaroo rats were observed in the Action Area during 2008, 2009, 2010, 2011, and 2012 surveys; however, based on existing information in the CNDDB and personal communications with local experts, Tipton kangaroo rats are presumed to be present in some areas along the natural gas pipeline. Potential effects could include temporary loss of habitat during construction, and mortality of individuals caused by construction activities. The proposed action would temporarily remove up to 3.7 acres of habitat potentially occupied by Tipton kangaroo rat. In addition, the OEHI Project actions would temporarily remove up to 28.89 acres and permanently remove approximately 63.90 acres of habitat potentially occupied by Tipton kangaroo rat. This is the same area identified for blunt-nosed leopard lizard above. The avoidance and conservation measures BIO-4, BIO-7, BIO-8, BIO-14, BIO-12, and BIO-15 described in Section 2.3 would substantially reduce the potential for direct effects on the Tipton kangaroo rats, which were known to occur in the region, for the HECA Project and the portion of the CO_2 pipeline not within the EHOF. For the portions of the project within the EHOF, the avoidance measures in the 1995 Biological Opinion issued by the USFWS and 1997 MOU between Oxy and the California CDFG as amended, and the HCP for the EHOF, when approved, would substantially reduce the potential for direct effects on the Tipton kangaroo rats. Also, habitat compensation, as described by conservation measure BIO-18 (HECA Project), and the 1995 USFWS Biological Opinion (USFWS File # l-1-95-F-102) and draft HCP currently under review by the USFWS (OEHI Project),will provide additional benefits for long-term survival and recovery of the Tipton kangaroo rat.

6.3.4 San Joaquin Kit Fox

The proposed action **may affect, and is likely to adversely affect** the San Joaquin kit fox. San Joaquin kit fox signs were observed during surveys in the Elk Hills area (southwest of the Kern River Flood Control Channel) between 2008 and 2010. Based on these observations and other existing information reviewed for this BA, San Joaquin kit fox are presumed to be present along the CO_2 pipeline (OEHI, 2012). Based on field observations and habitat characteristics, kit fox are substantially less likely to be present along the natural gas pipeline alignment, electrical transmission line, or at the Project Site. Potential effects could include temporary loss of habitat during construction, permanent loss of low-quality migration/movement habitat at the HECA Project Site, and mortality of individuals caused by construction activities and HECA Project operations. The OEHI Project actions would temporarily remove up to 28.89 acres and permanently remove approximately 0.11 acre of habitats that provide all constituent elements (breeding, foraging, and migration) required by San Joaquin kit fox. These 29 acres overlap entirely with the acreage already identified for blunt-nosed leopard lizard above. These impacts would occur only in the CO_2 pipeline construction limits in the Elk Hills area. The Natural/ Ruderal (Allscale Scrub) habitats elsewhere in the HECA Project area are less likely to provide habitat for breeding and foraging kit foxes.

Based on the conservative traffic model described in Section 5.5.4, construction and operation traffic could result in mortality of approximately 39 kit foxes over the course of the 25-year HECA Project lifespan. This mortality would be spread over an area of approximately 3,000 square miles, so the impact to any one population would be minimal on an annual basis. The avoidance and conservation measures BIO-4, BIO-7, and BIO-13 described in Section 2.3 would substantially reduce the potential for direct effects on the San Joaquin kit fox from the HECA Project and portion of the CO_2 pipeline not within the EHOF. For the portions of the pipeline within the EHOF, the avoidance measures in the 1995 Biological Opinion issued by the USFWS and 1997 MOU between Oxy and the California CDFG as updated, would minimize or avoid direct effects on the San Joaquin Kit Fox. Also, habitat compensation, as described by conservation measure BIO-18 (HECA Project), and the 1995 USFWS Biological Opinion (USFWS File # l-1-95-F-102) and the draft HCP currently under review by the USFWS (OEHI Project), will improve recovery and survival of the kit fox populations in the region by establishing additional permanent conservation areas, and implementing land management activities that will facilitate better regional protection for habitats used by this species. Additional land management activities that may be implemented on existing conservation lands include control of non-native species, limiting off-road vehicle access, and installation of fencing to reduce trespass and trash disposal.

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Reviewer:	Steve Leach, Senior Biologist

Major Cities
Minor Cities
Major Highways
State Boundaries
County Boundaries

N

0 30 60
Miles

PROJECT LOCATION

February 2013
28068052

Biological Assessment
Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 1

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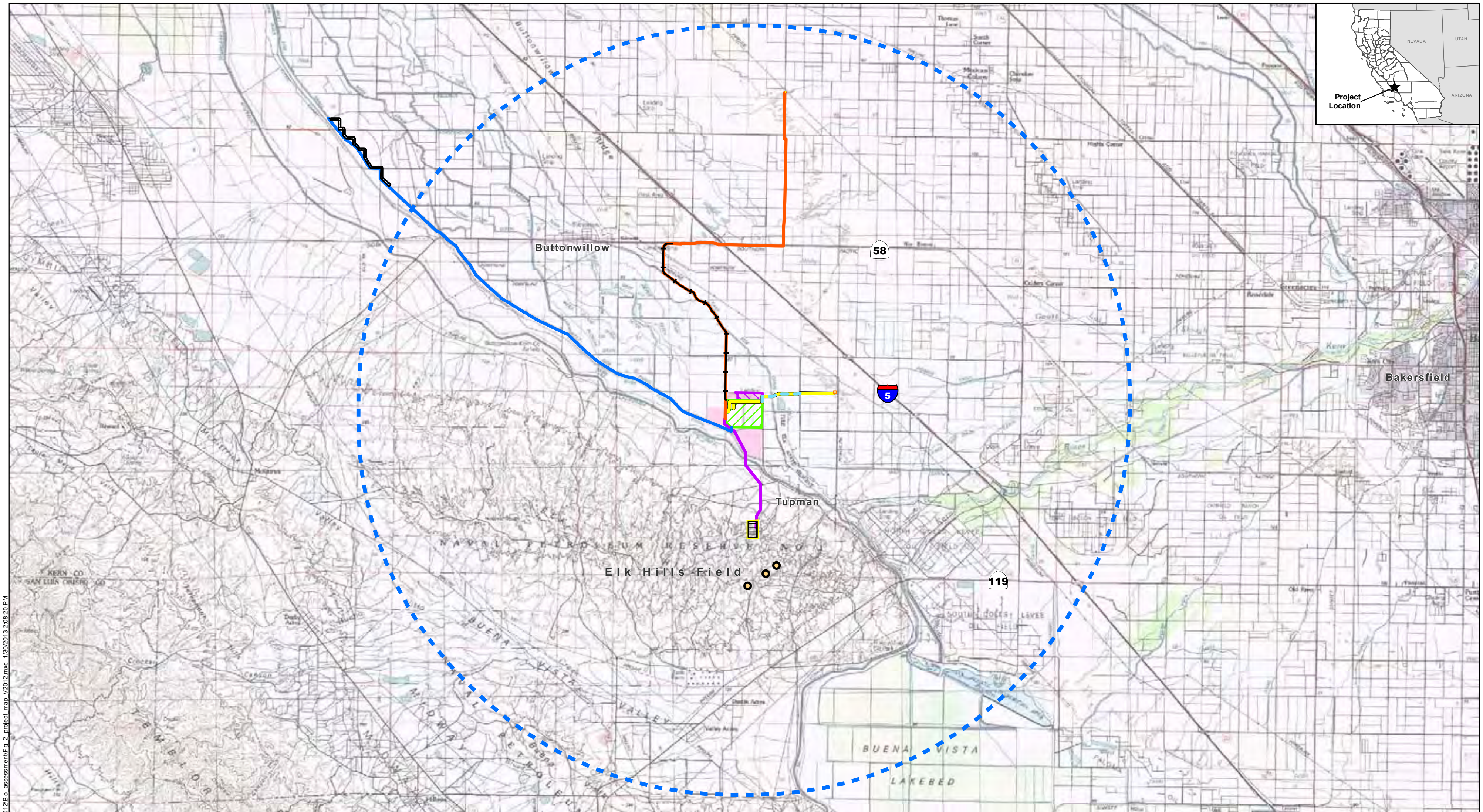

- Project Site
- Construction Staging Area
- Controlled Area
- BVWSD Well Field
- Electrical Switching Station
- 10-Mile Radius from Project Site
- Carbon Dioxide
- Natural Gas
- Potable Water
- Process Water
- Railroad
- Transmission

OEHI CO2 EOR Project
- EOR Processing Facility
- EOR Satellite Gathering Station

N

0 1 2 Miles

PROJECT VICINITY

February 2013
28068052

Biological Assessment
Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 2

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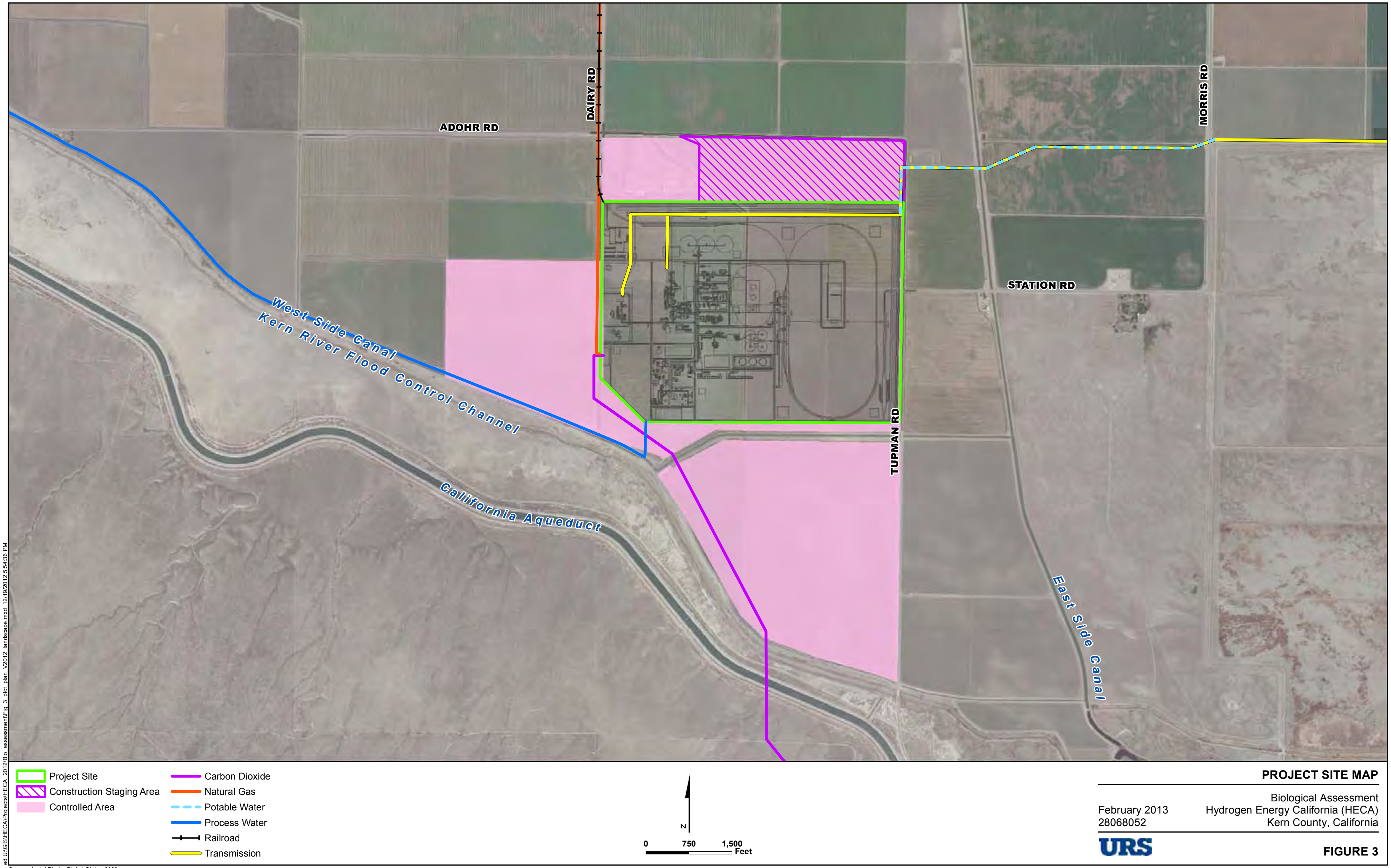
Sources: USGS (30'x60' quads: Taft 1982, Delano 1982). Created using TOPO!, ©2006 National Geographic Maps, All Rights Reserved. HECA Project Team (Biological Data, 2009)



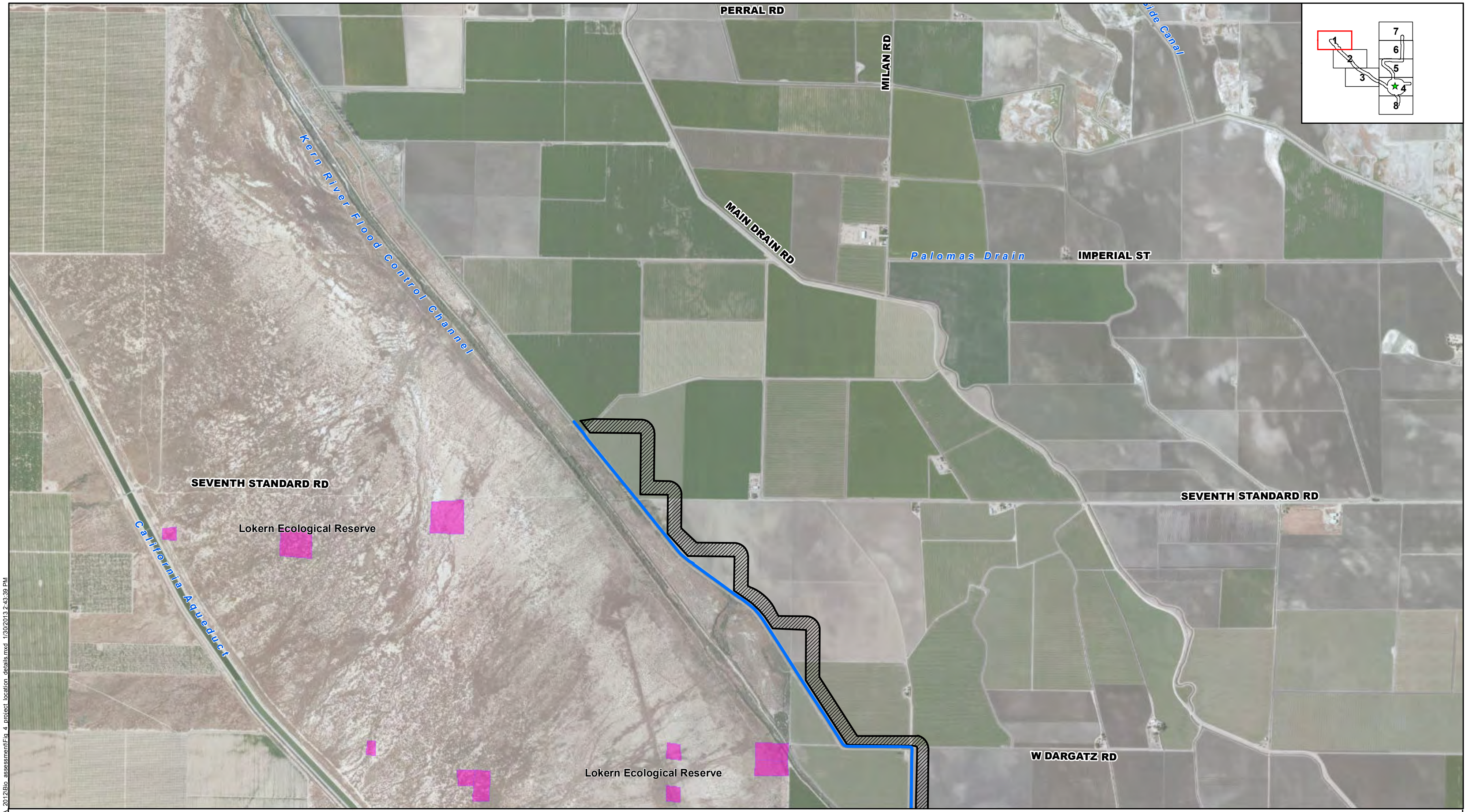
PROJECT SITE MAP

Biological Assessment
February 2013 Hydrogen Energy California (HECA)
28068052 Kern County, California

URS

FIGURE 3

Source: Aerial Photo, Digital Globe, 2008.



Project Site
Construction Staging Area
Controlled Area
BVWSD Well Field
Elk Hills Conservation Area
Carbon Dioxide
Natural Gas
Potable Water
Process Water
Railroad
Transmission
Proposed Natural Gas Valve Station
Rail Laydown Yard
HDD Entry/Exit Pits
Electrical Switching Station
OEHI CO2 EOR Project
EOR Processing Facility
EOR Satellite Gathering Station

Note:
HDD = Horizontal Directional Drilling

N

0 1,000 2,000 Feet

PROJECT LOCATION DETAILS

February 2013
28068052

Biological Assessment
Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 4 (1)

Source: Aerial Imagery, Bing Maps Hybrid, 2010

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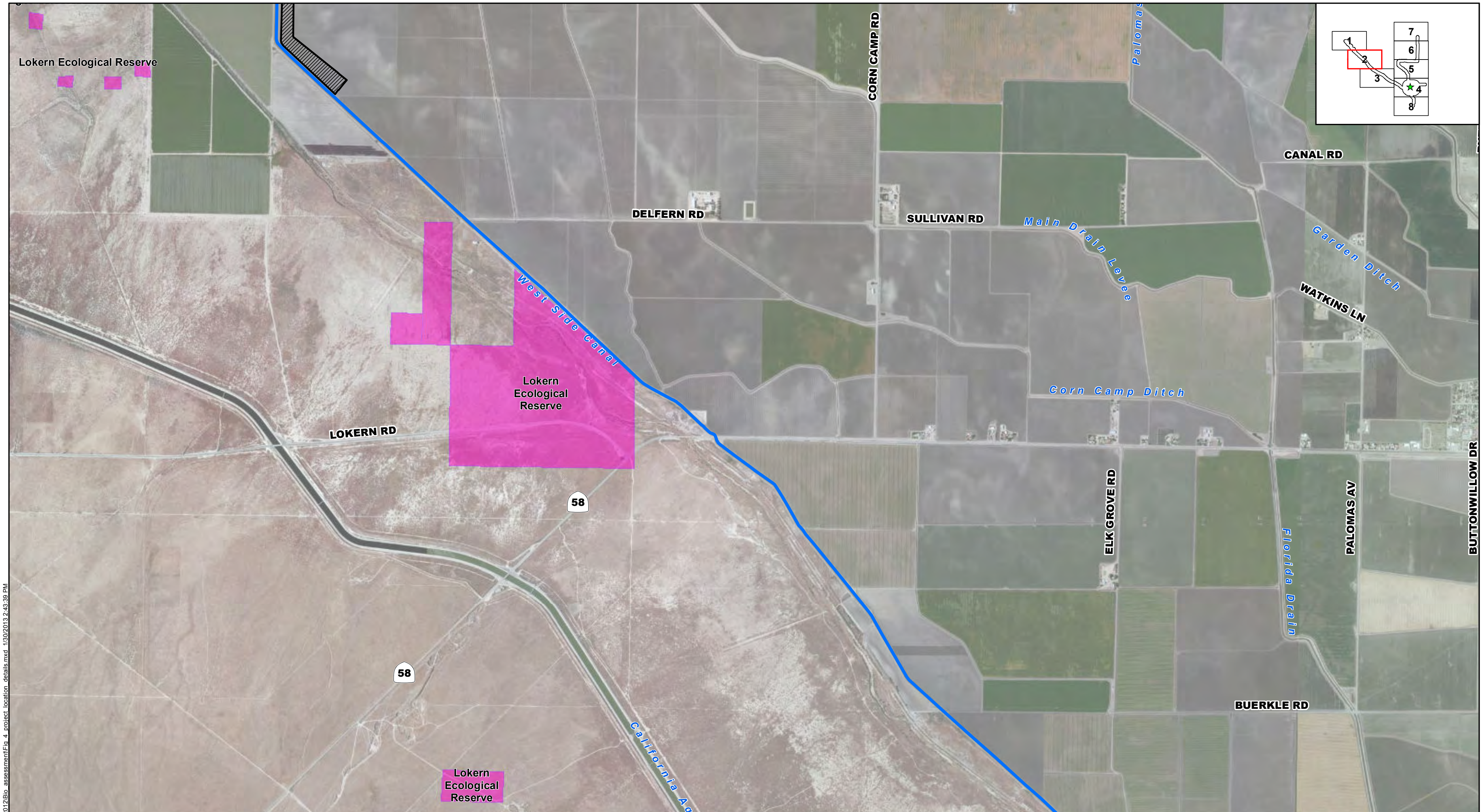


- Project Site
- Construction Staging Area
- Controlled Area
- BVWSD Well Field
- Elk Hills Conservation Area
- Carbon Dioxide
- Natural Gas
- Potable Water
- Process Water
- Railroad
- Transmission
- Proposed Natural Gas Valve Station
- Rail Laydown Yard
- HDD Entry/Exit Pits
- Electrical Switching Station

OEHI CO2 EOR Project
- EOR Processing Facility
- EOR Satellite Gathering Station

Note:
HDD = Horizontal Directional Drilling

N

0 1,000 2,000 Feet

PROJECT LOCATION DETAILS

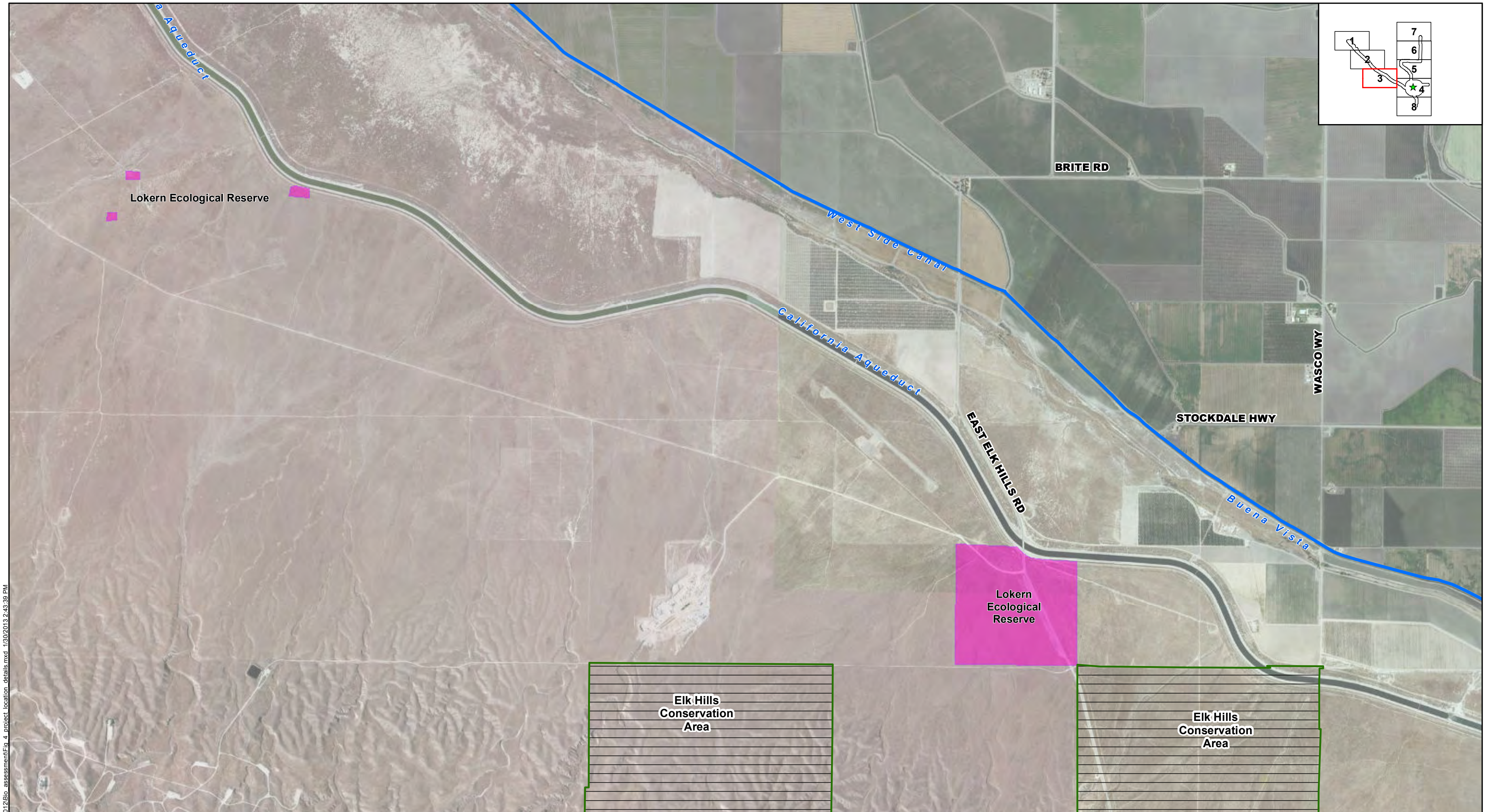
Biological Assessment
Hydrogen Energy California (HECA)
Kern County, California

February 2013
28068052

URS

FIGURE 4 (2)

Source: Aerial Imagery, Bing Maps Hybrid, 2010



- Project Site
- Construction Staging Area
- Controlled Area
- BVWSD Well Field
- Elk Hills Conservation Area
- Carbon Dioxide
- Natural Gas
- Potable Water
- Process Water
- Railroad
- Transmission
- Proposed Natural Gas Valve Station
- Rail Laydown Yard
- HDD Entry/Exit Pits
- Electrical Switching Station

OEHI CO2 EOR Project
- EOR Processing Facility
- EOR Satellite Gathering Station

Note:
HDD = Horizontal Directional Drilling

N

0 1,000 2,000 Feet

PROJECT LOCATION DETAILS

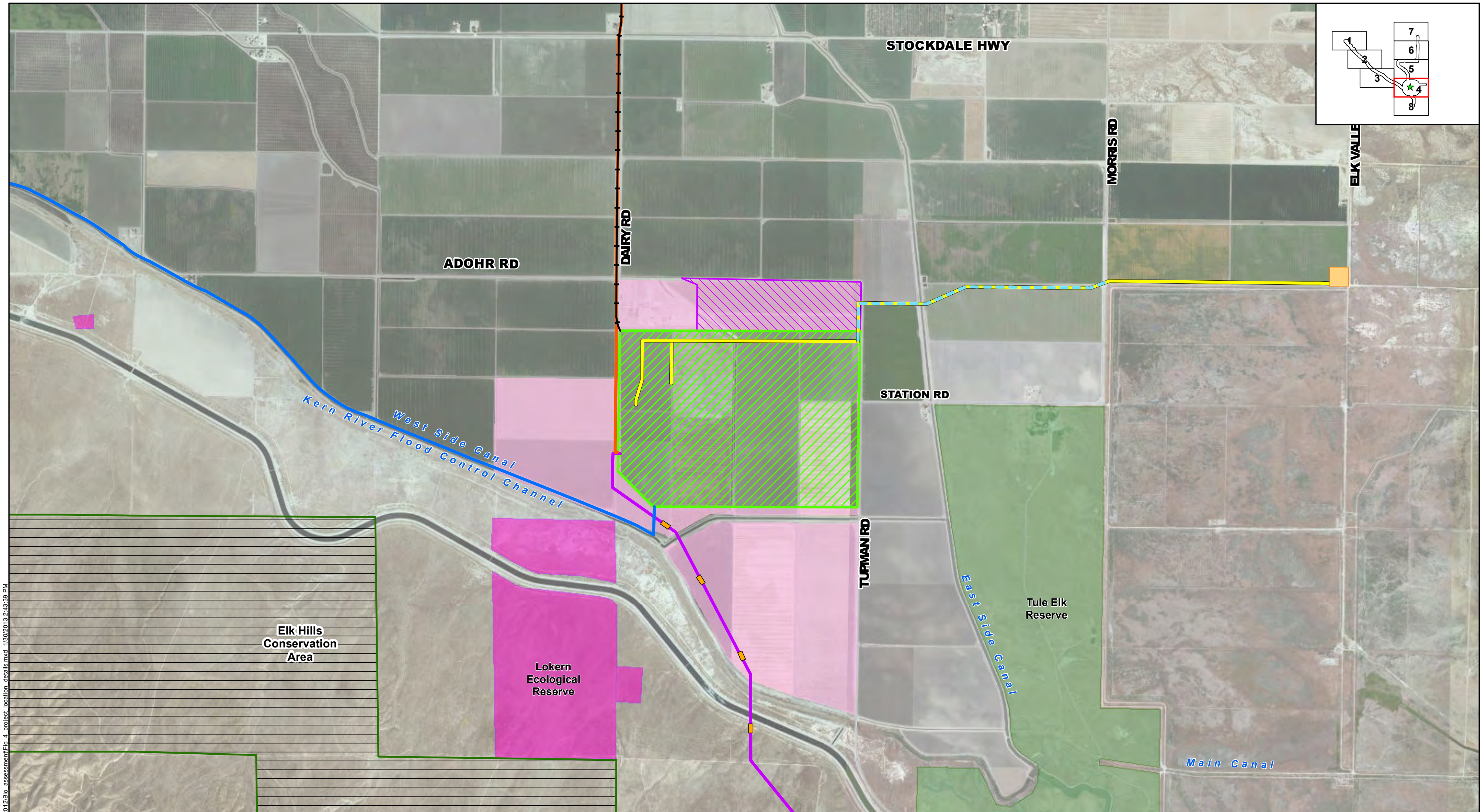
Biological Assessment
Hydrogen Energy California (HECA)
Kern County, California

February 2013
28068052

URS

FIGURE 4 (3)

Source: Aerial Imagery, Bing Maps Hybrid, 2010



- Project Site
- Construction Staging Area
- Controlled Area
- BVWSD Well Field
- Elk Hills Conservation Area
- Carbon Dioxide
- Natural Gas
- Potable Water
- Process Water
- Railroad
- Transmission
- Proposed Natural Gas Valve Station
- Rail Laydown Yard
- HDD Entry/Exit Pits
- Electrical Switching Station

OEHI CO2 EOR Project

- EOR Processing Facility
- EOR Satellite Gathering Station

N

0 1,000 2,000 Feet

Note:
HDD = Horizontal Directional Drilling

PROJECT LOCATION DETAILS

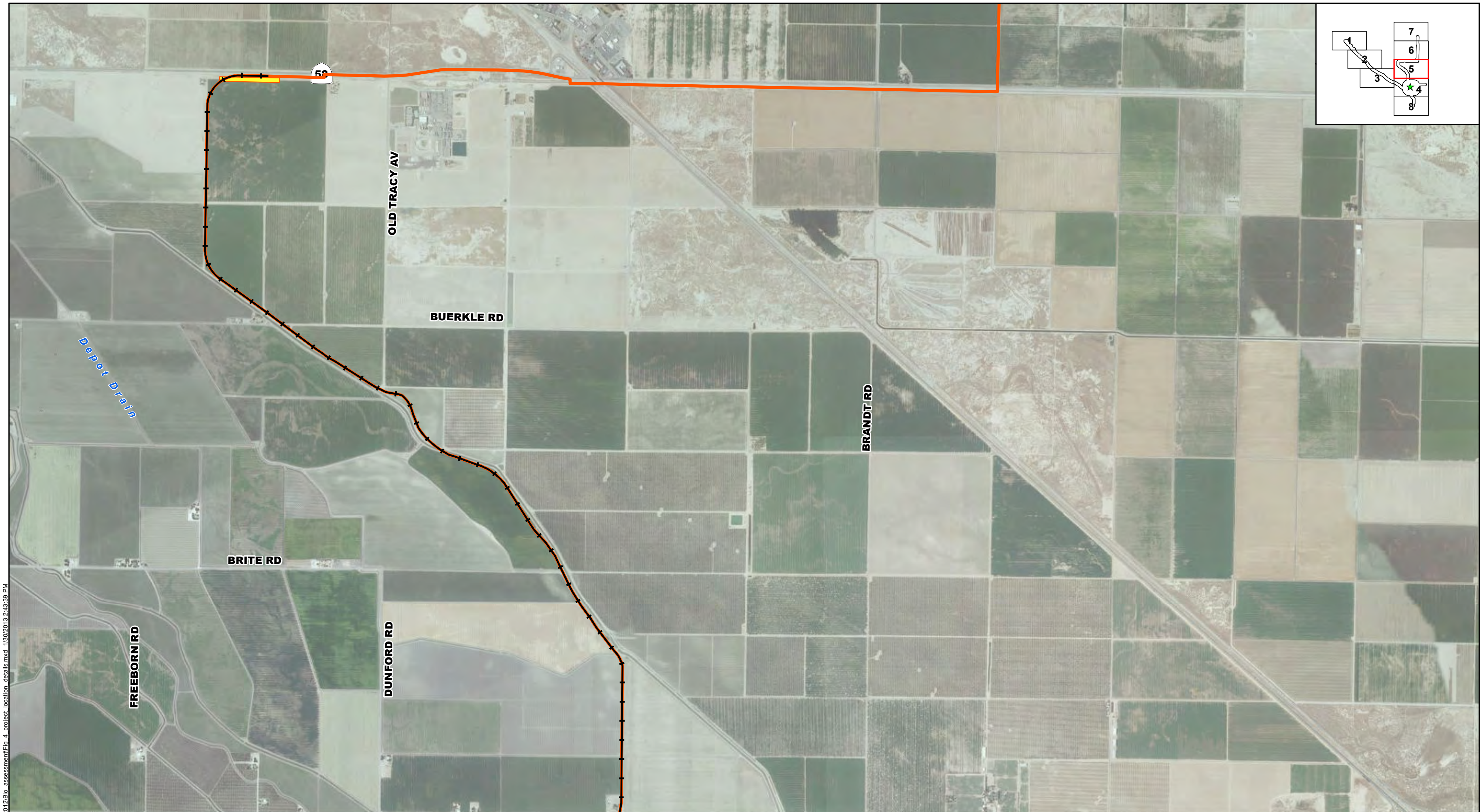
February 2013
28068052

Biological Assessment
Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 4 (4)

Source: Aerial Imagery, Bing Maps Hybrid, 2010



- Project Site
- Construction Staging Area
- Controlled Area
- BVWSD Well Field
- Elk Hills Conservation Area
- Carbon Dioxide
- Natural Gas
- Potable Water
- Process Water
- Railroad
- Transmission
- Proposed Natural Gas Valve Station
- Rail Laydown Yard
- HDD Entry/Exit Pits
- Electrical Switching Station

OEHI CO2 EOR Project

- EOR Processing Facility
- EOR Satellite Gathering Station

Note:
HDD = Horizontal Directional Drilling

N

0 1,000 2,000
Feet

PROJECT LOCATION DETAILS

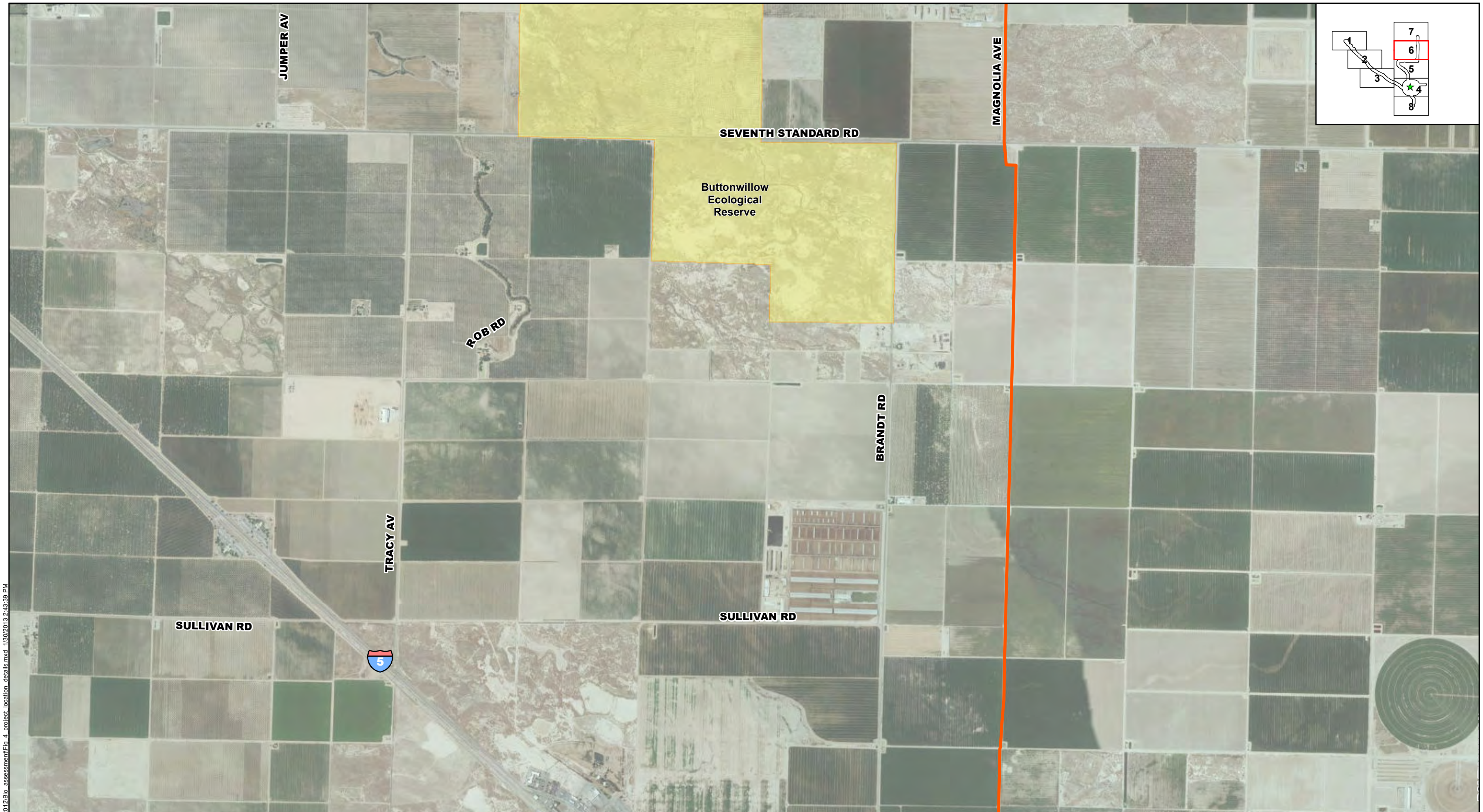
Biological Assessment
Hydrogen Energy California (HECA)
Kern County, California

February 2013
28068052

URS

FIGURE 4 (5)

Source: Aerial Imagery, Bing Maps Hybrid, 2010



Project Site
Construction Staging Area
Controlled Area
BVWSD Well Field
Elk Hills Conservation Area
Carbon Dioxide
Natural Gas
Potable Water
Process Water
Railroad
Transmission
Proposed Natural Gas Valve Station
Rail Laydown Yard
HDD Entry/Exit Pits
Electrical Switching Station
OEHI CO2 EOR Project
EOR Processing Facility
EOR Satellite Gathering Station

Note:
HDD = Horizontal Directional Drilling

N

0 1,000 2,000 Feet

PROJECT LOCATION DETAILS

February 2013
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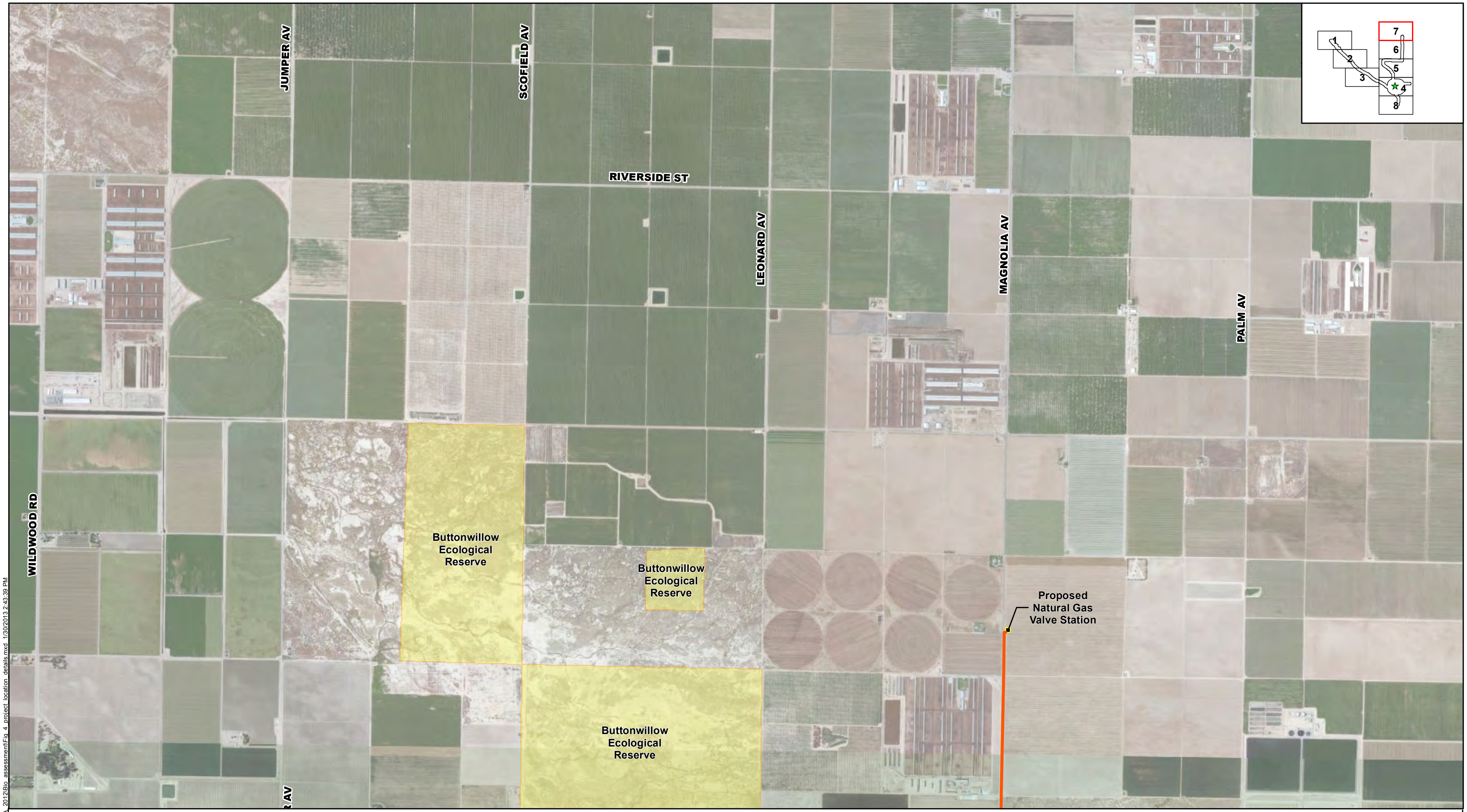
Biological Assessment
Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 4 (6)

Source: Aerial Imagery, Bing Maps Hybrid, 2010



- Project Site
- Construction Staging Area
- Controlled Area
- BVWSD Well Field
- Elk Hills Conservation Area
- Carbon Dioxide
- Natural Gas
- Potable Water
- Process Water
- Railroad
- Transmission
- Proposed Natural Gas Valve Station
- Rail Laydown Yard
- HDD Entry/Exit Pits
- Electrical Switching Station

OEHI CO2 EOR Project
- EOR Processing Facility
- EOR Satellite Gathering Station

Note:
HDD = Horizontal Directional Drilling

N

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PROJECT LOCATION DETAILS

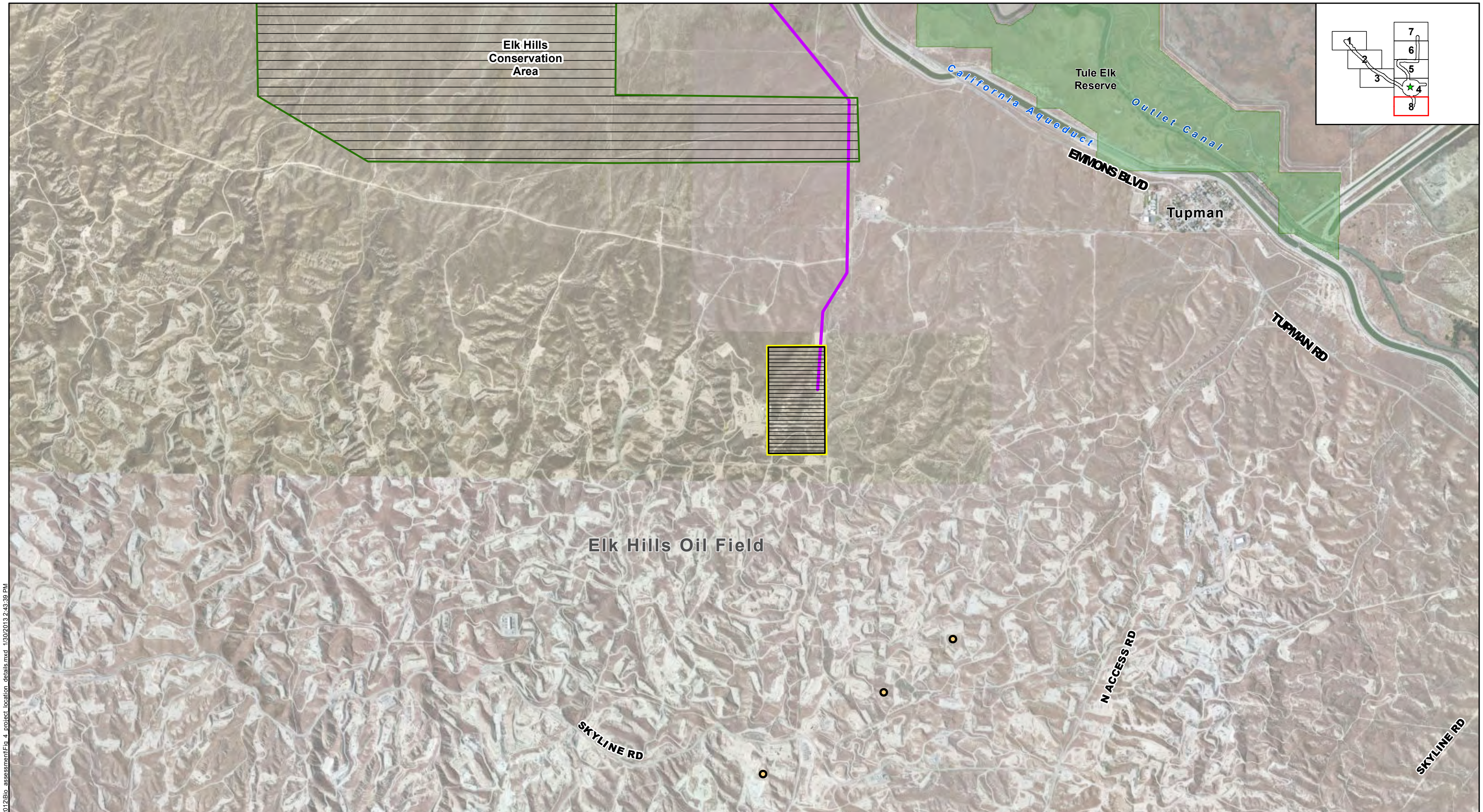
Biological Assessment
Hydrogen Energy California (HECA)
Kern County, California

February 2013
28068052

URS

FIGURE 4 (7)

Source: Aerial Imagery, Bing Maps Hybrid, 2010



Project Site
Construction Staging Area
Controlled Area
BVWSD Well Field
Elk Hills Conservation Area

Carbon Dioxide
Natural Gas
Potable Water
Process Water
Railroad
Transmission

Proposed Natural Gas Valve Station
Rail Laydown Yard
HDD Entry/Exit Pits
Electrical Switching Station

OEHI CO2 EOR Project
EOR Processing Facility
EOR Satellite Gathering Station

Note:
HDD = Horizontal Directional Drilling

N

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Feet

PROJECT LOCATION DETAILS

February 2013
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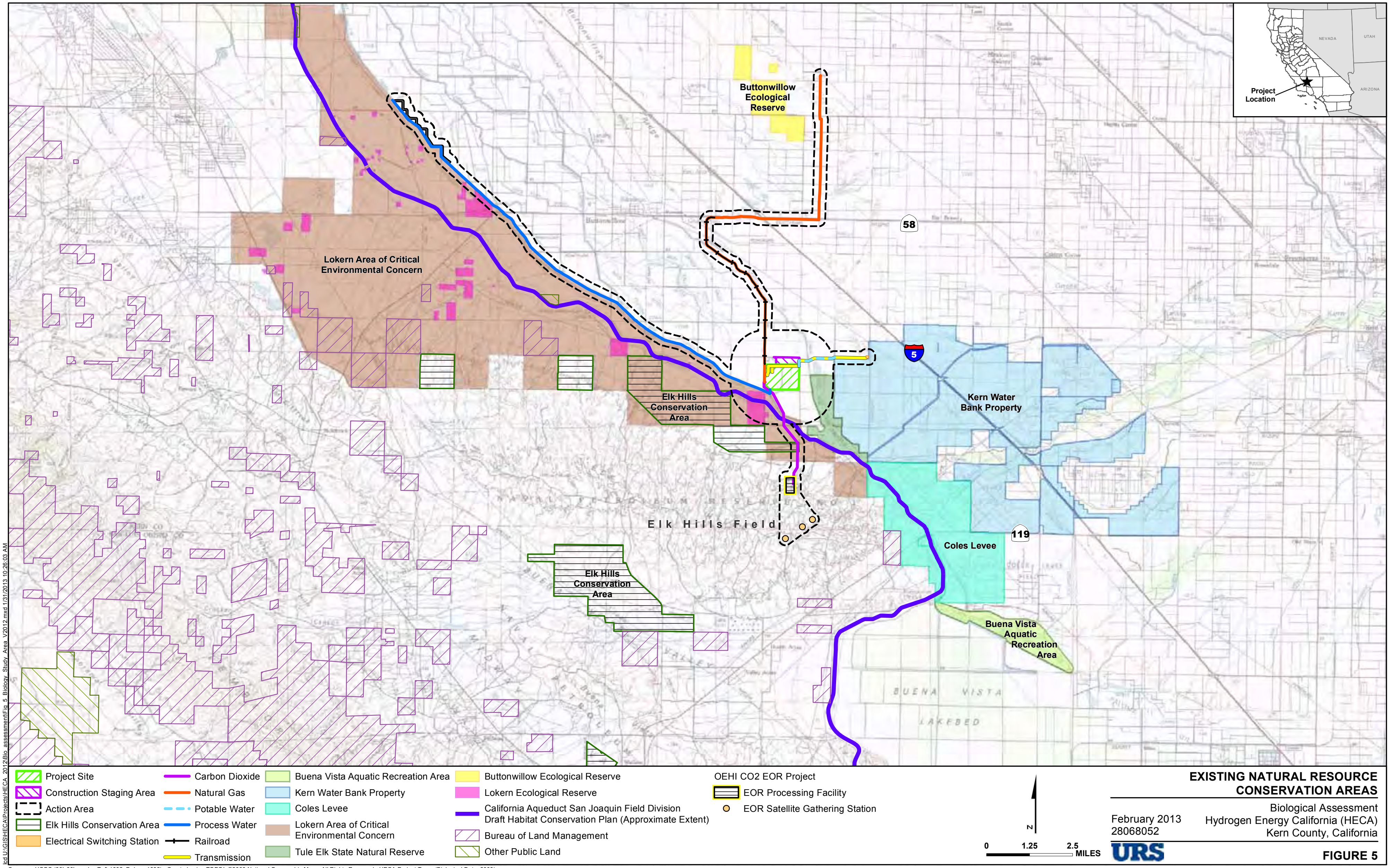
Biological Assessment
Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 4 (8)

Source: Aerial Imagery, Bing Maps Hybrid, 2010



EXISTING NATURAL RESOURCE CONSERVATION AREAS

Biological Assessment
Hydrogen Energy California (HECA)
Kern County, California

February 2013
28068052

FIGURE 5

Sources: USGS (30'x60' quads: Taft 1982, Delano 1982). Created using TOPO!, ©2006 National Geographic Maps, All Rights Reserved. HECA Project Team (Biological Data, 2009)

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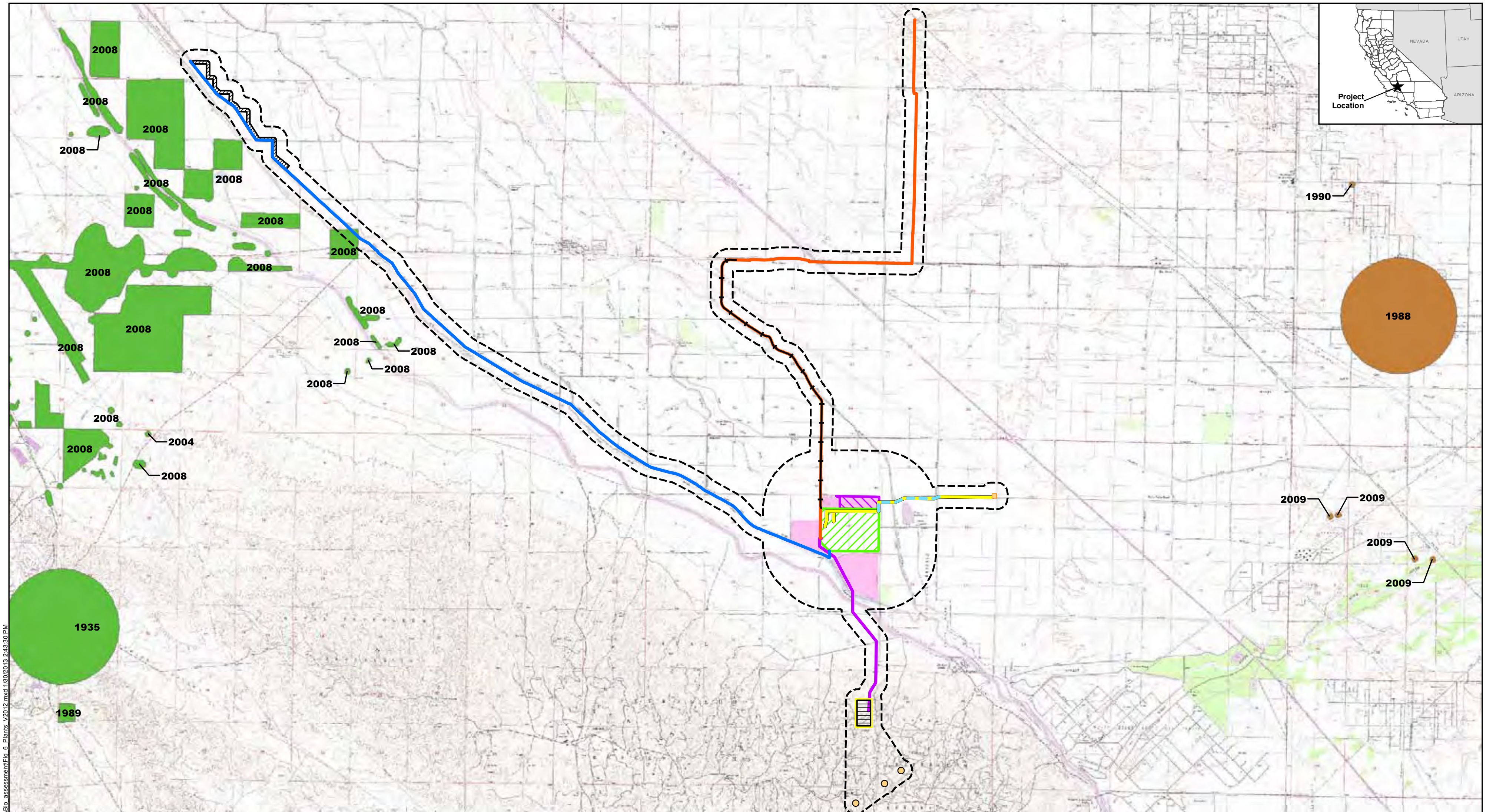

Project Site	Carbon Dioxide	San Joaquin Woollythreads	OEHI CO2 EOR Project
Construction Staging Area	Natural Gas	Kern Mallow	EOR Processing Facility
Controlled Area	Potable Water		EOR Satellite Gathering Station
BVWSD Well Field	Process Water		
Electrical Switching Station	Railroad		
	Transmission		

Note:
No known occurrences of California jewel-flower or Bakersfield cactus in area covered by this map.

N

0 0.75 1.5 MILES

FEDERALLY LISTED PLANT SPECIES NEAR THE ACTION AREA

February 2013
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Biological Assessment
Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 6

Source: USGS 7.5-minute quadrangles: Buttonwillow, published 1973 (rev 1976), East Elk Hills, published 1973 (rev 1977), Lokern, published 1973 (rev 1976), Tupman, published 1973 (rev 1977), West Elk Hills, published 1973 (rev 1976); Species data, CNDDB, April 2012.

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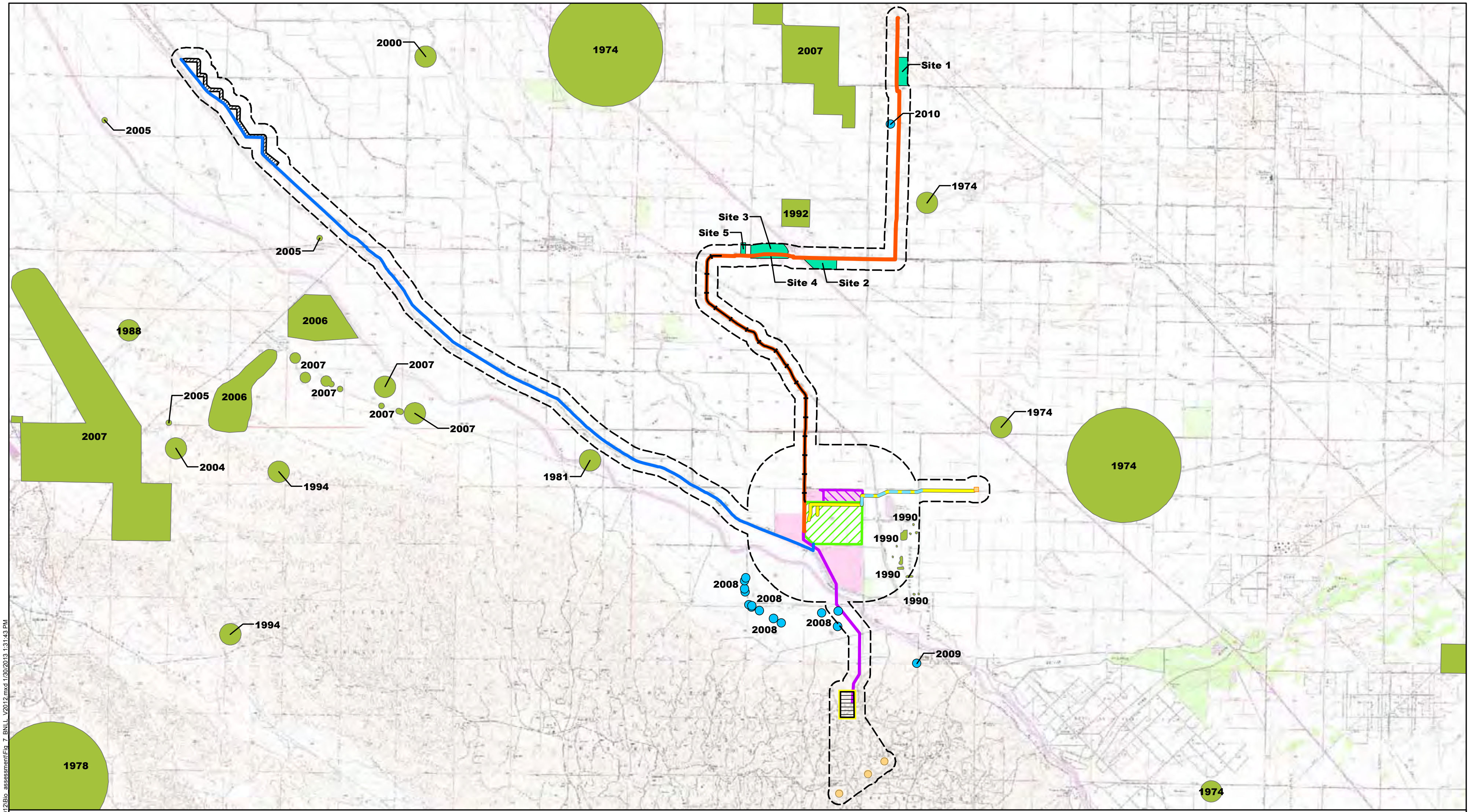

Project Site
Construction Staging Area
Controlled Area
Action Area
BVWSD Well Field
Electrical Switching Station
BNLL - CNDDB records
2012 Survey Area
BNLL - URS observation
Carbon Dioxide
Natural Gas
Potable Water
Process Water
Railroad
Transmission
OEHI CO2 EOR Project
EOR Processing Facility
EOR Satellite Gathering Station

BLUNT-NOSED LEOPARD LIZARD OCCURRENCES NEAR THE ACTION AREA

February 2013
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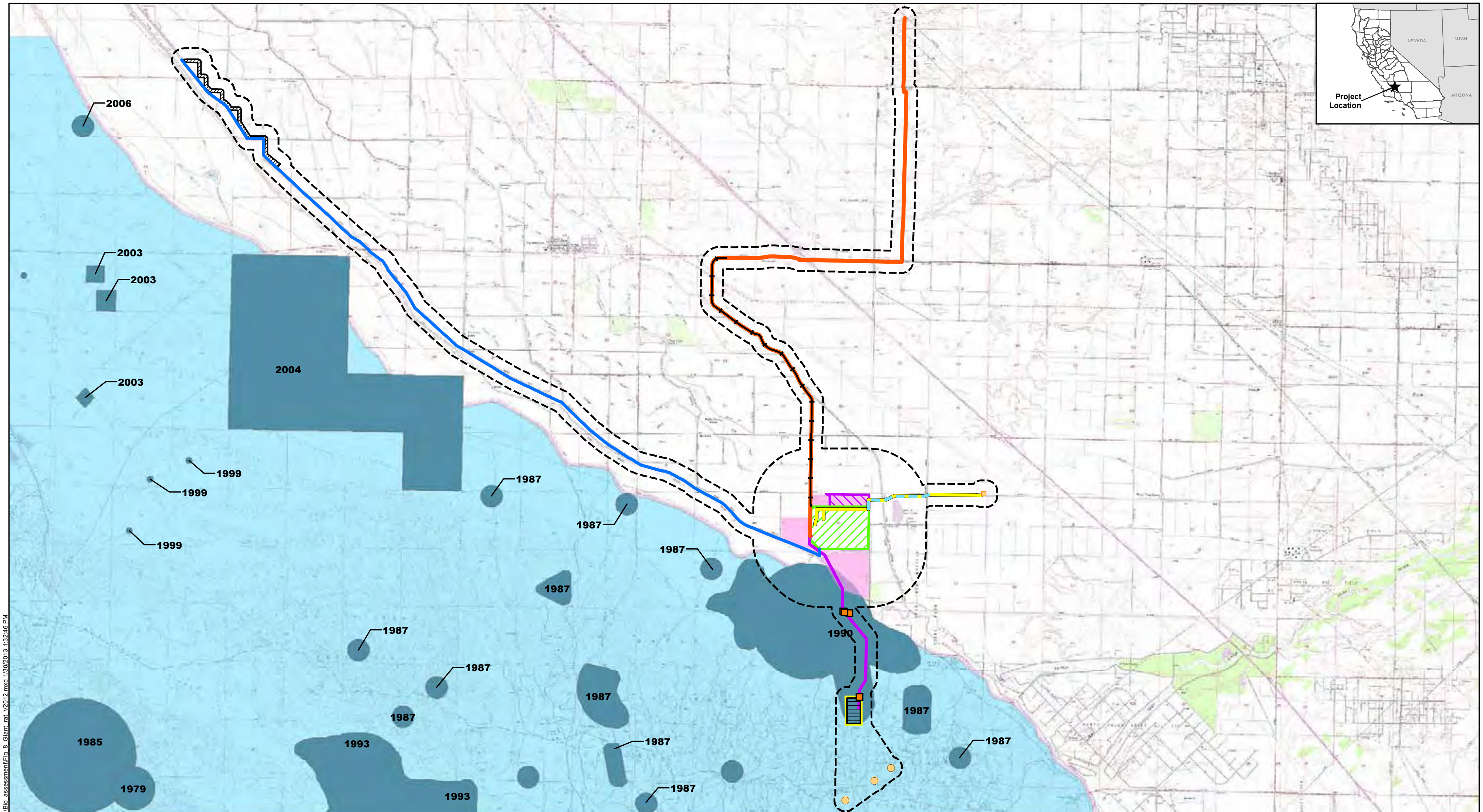
Biological Assessment
Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 7

Source: USGS 7.5-minute quadrangles: Buttonwillow, published 1973 (rev 1976), East Elk Hills, published 1973 (rev 1977), Lokern, published 1973 (rev 1976), Tupman, published 1973 (rev 1977), West Elk Hills, published 1973 (rev 1976); Species data, CNDDB, 2012.



Project Site	Carbon Dioxide	Giant Kangaroo Rat (CNDDB Records)
Construction Staging Area	Natural Gas	Giant Kangaroo Rat (Presumed Occupied)
Controlled Area	Potable Water	Giant Kangaroo Rat Precint (Stantec 2013)
BVWSD Well Field	Process Water	
Electrical Switching Station	Railroad	
	Transmission	

OEHI CO2 EOR Project
- EOR Processing Facility
- EOR Satellite Gathering Station

N

0 0.75 1.5 MILES

GIANT KANGAROO RAT OCCURRENCES NEAR THE ACTION AREA

February 2013
28068052

Biological Assessment
Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 8

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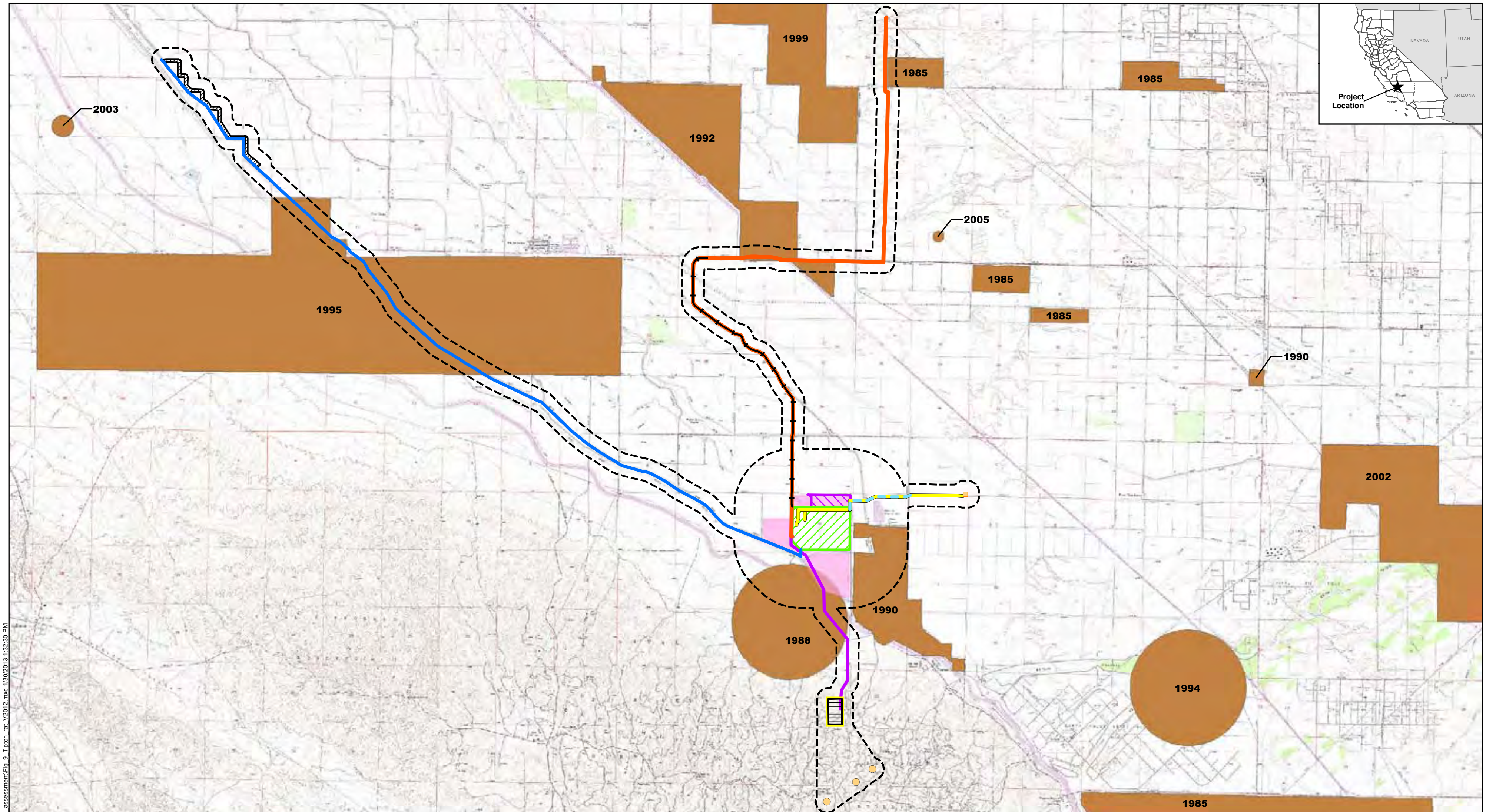
Source: USGS 7.5-minute quadrangles: Buttonwillow, published 1973 (rev 1976), East Elk Hills, published 1973 (rev 1977), Lokern, published 1973 (rev 1976), Tupman, published 1973 (rev 1977), West Elk Hills, published 1973 (rev 1976); Species data, CNDDB, April 2012; Stantec. 2013. 2012 Special-Status Species Surveys for Initial CO2 Injection Phase. OEHI. January 8.



Project Site	Carbon Dioxide
Construction Staging Area	Natural Gas
Controlled Area	Potable Water
BVWSD Well Field	Process Water
Electrical Switching Station	Railroad
	Transmission

Tipton Kangaroo Rat (CNDDB Records)

OEHI CO2 EOR Project
- EOR Processing Facility
- EOR Satellite Gathering Station

N

0 0.75 1.5 MILES

TIPTON KANGAROO RAT OCCURRENCES NEAR THE ACTION AREA

February 2013
28068052

Biological Assessment
Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 9

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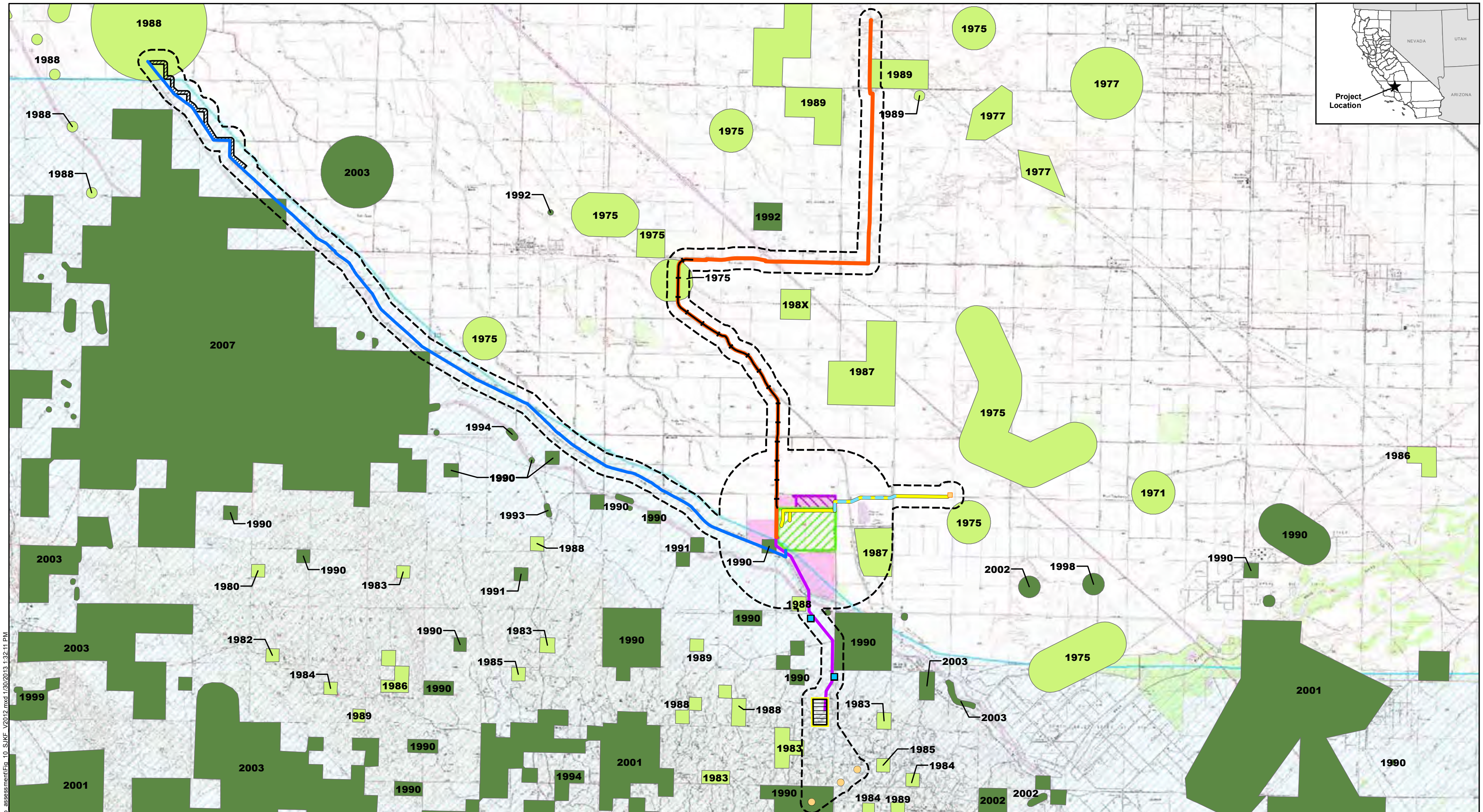
Source: USGS 7.5-minute quadrangles: Buttonwillow, published 1973 (rev 1976), East Elk Hills, published 1973 (rev 1977), Lokern, published 1973 (rev 1976), Tupman, published 1973 (rev 1977), West Elk Hills, published 1973 (rev 1976); Species data, CNDDB, April 2012.



Project Site
Construction Staging Area
Controlled Area
BVWSD Well Field
Electrical Switching Station
Carbon Dioxide
Natural Gas
Potable Water
Process Water
Railroad
Transmission
San Joaquin Kit Fox (1990 to present)
San Joaquin Kit Fox (1989 and older)
San Joaquin Kit Fox Recovery Area - Core
Potentially active San Joaquin Kit Fox Den (Stantec 2013)
OEHI CO2 EOR Project
EOR Processing Facility
EOR Satellite Gathering Station

SAN JOAQUIN KIT FOX OCCURRENCES NEAR THE ACTION AREA

Biological Assessment
Hydrogen Energy California (HECA)
Kern County, California

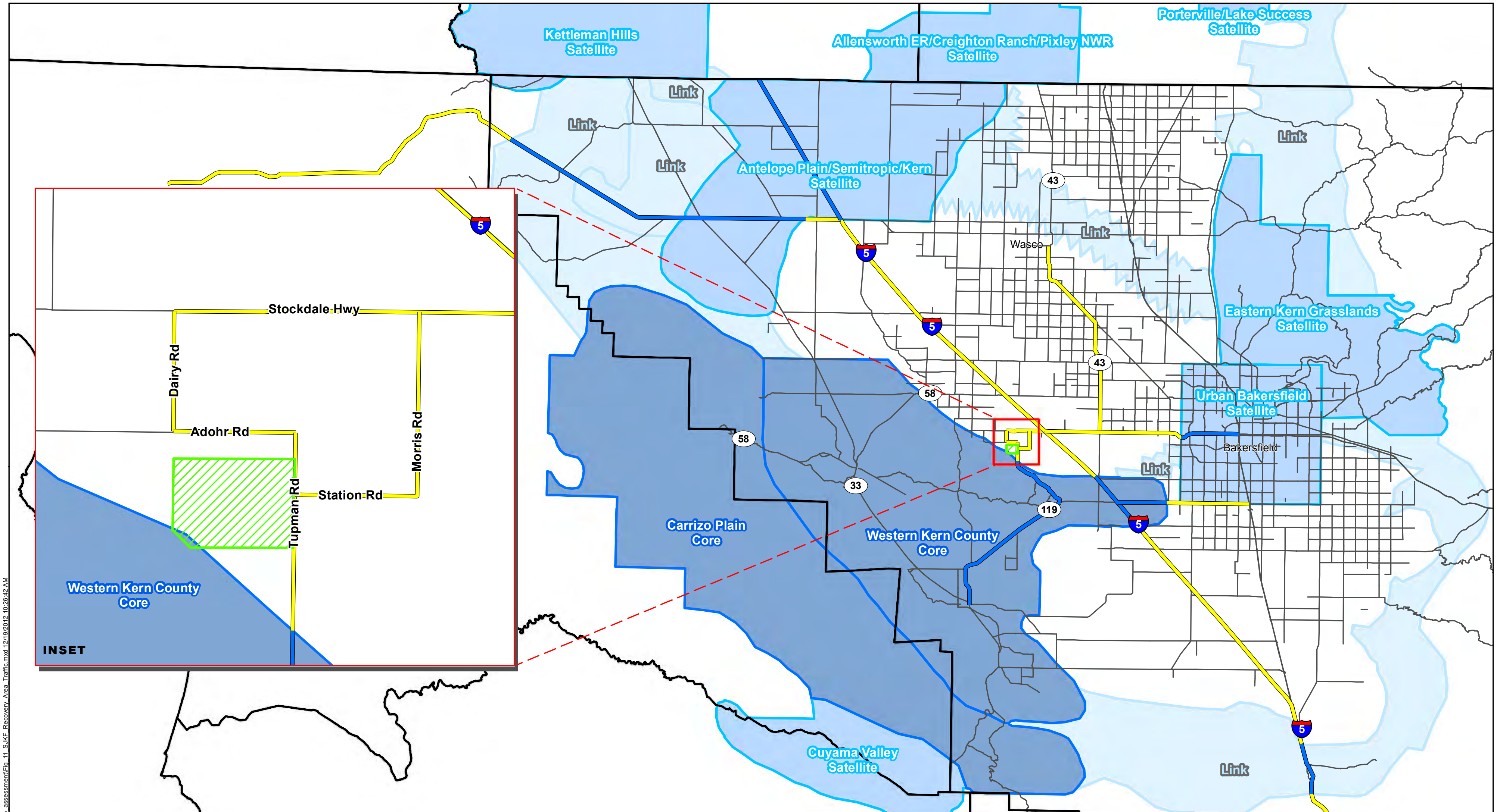
February 2013
28068052

URS

FIGURE 10

U:\GIS\HECA\Projects\HECA_2012\Bio_assessment\Fig_10_SJKF_V2012.mxd 1/30/2013 1:32:11 PM

Source: USGS 7.5-minute quadrangles: Buttonwillow, published 1973 (rev 1976), East Elk Hills, published 1973 (rev 1977), Lokern, published 1973 (rev 1976), Tupman, published 1973 (rev 1977), West Elk Hills, published 1973 (rev 1976); Species data, CNDDB, 2012; Stantec. 2013. 2012 Special-Status Species Surveys for Initial CO2 Injection Phase. OEHI. January 8.



Project Site

County Boundaries

Roads Utilized By Project Vehicles

Within Recovery Area

Outside Recovery Area

SJ Kit Fox Recovery Area (FWS 2007)

Core

Satellite

Link

N

0 4 8 Miles

SAN JOAQUIN KIT FOX RECOVERY AREA

February 2013
28068052

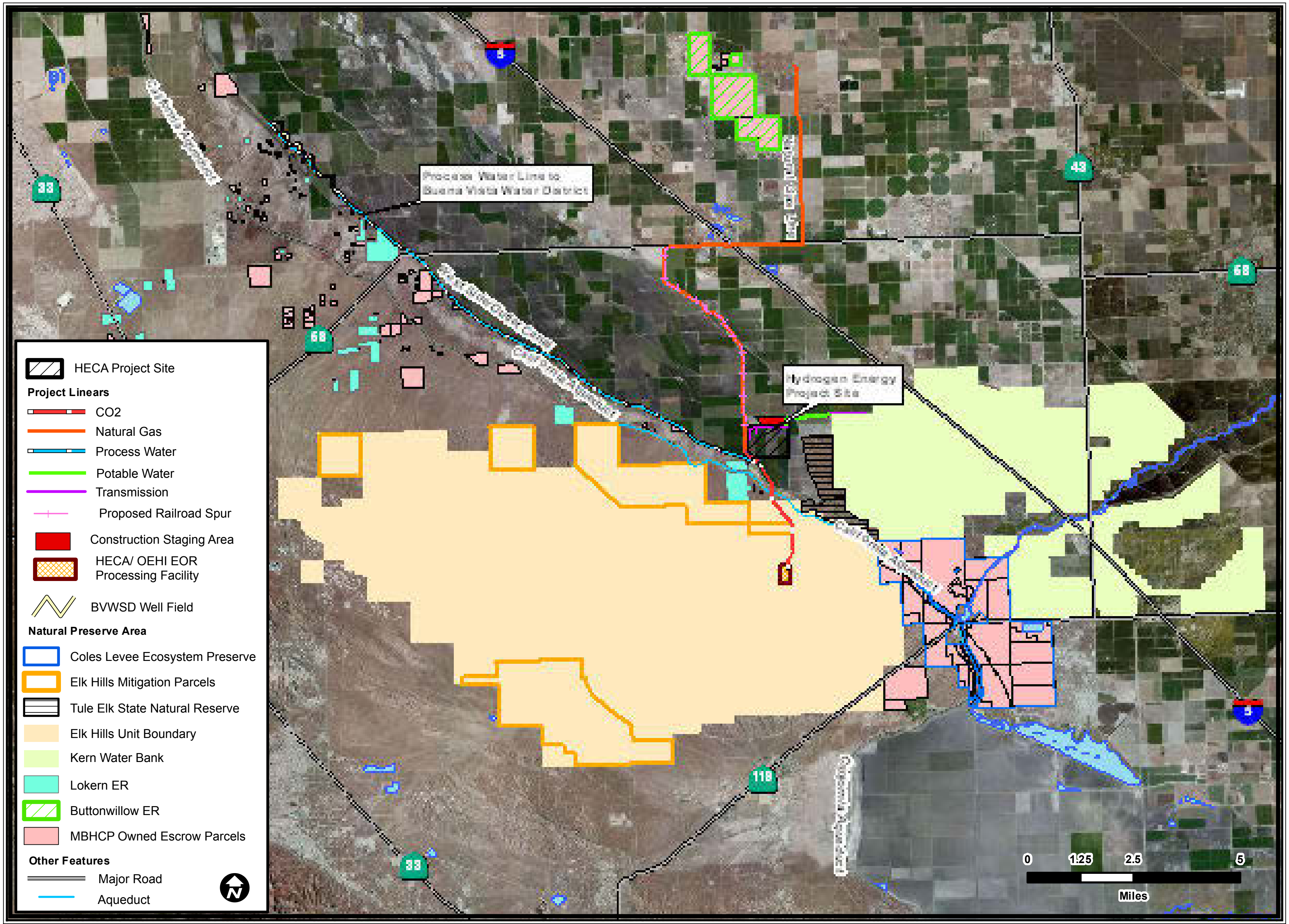
Biological Assessment
Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 11

BIOLOGICAL RESOURCES - FIGURE 1

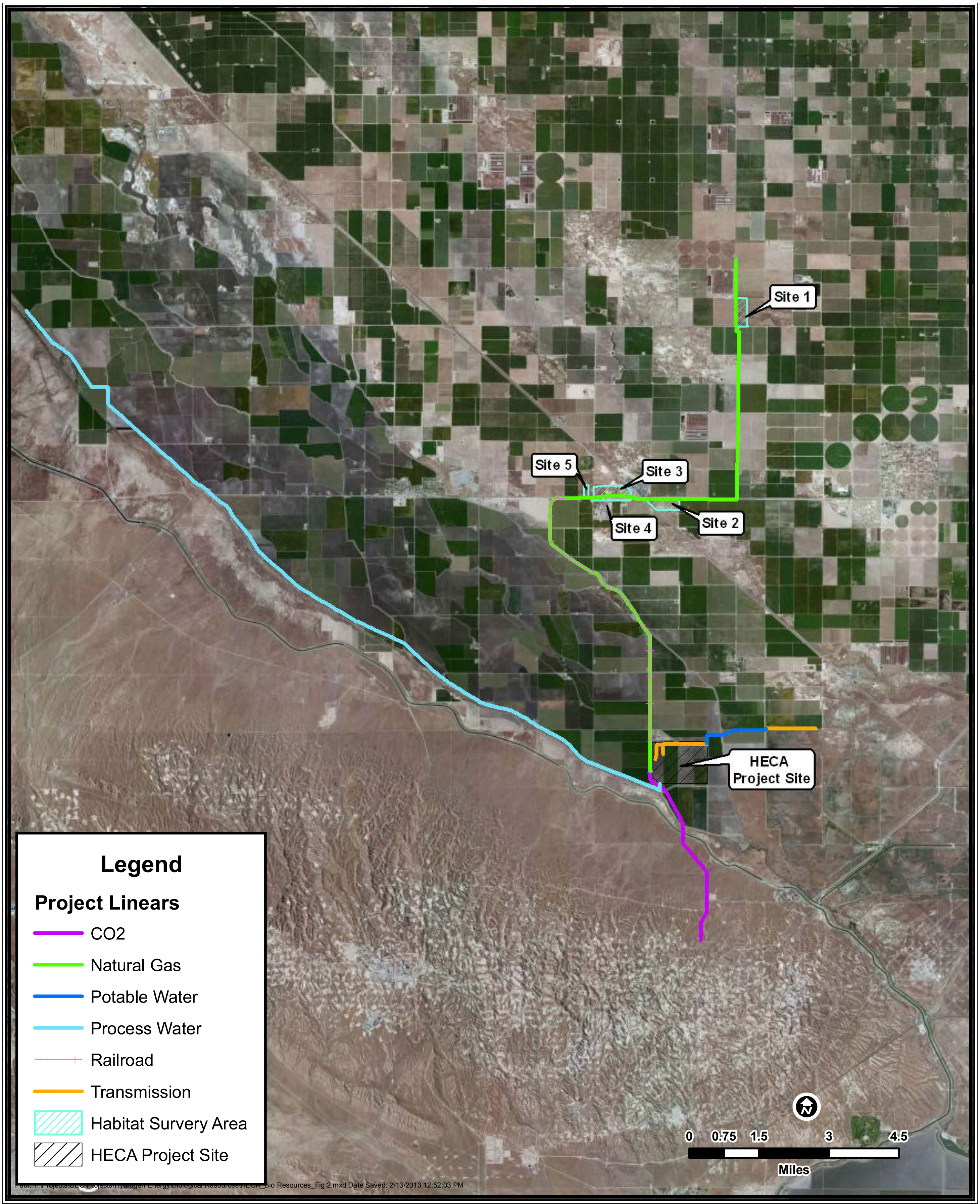
Hydrogen Energy California - Natural Preserve Areas



CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING DIVISION

SOURCE: URS & CDFW, Bing Aerial, OpenStreetMap - January 2013

BIOLOGICAL RESOURCES - FIGURE 2
Hydrogen Energy California - Project Facilities and Habitat Areas



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: URS AND ESRI

CARBON SEQUESTRATION AND GREENHOUSE GAS EMISSIONS

William Walters, P.E., David Vidaver, Abdel-Karim Abulaban, Ph.D., P.E., and Tad Patzek, Ph.D.

SUMMARY AND CONCLUSIONS

The Hydrogen Energy California project (HECA)[1] is planned to be an integrated gasification combined cycle power generating facility combined with a fertilizer manufacturing facility. HECA would gasify petroleum coke (petcoke) and coal to produce hydrogen rich fuel for a combustion turbine operating in combined cycle mode. The combined cycle plant would produce 416 megawatt (MW) gross electric power with an average, on-peak net export power output of 266 MW using hydrogen rich fuel[2]. HECA would separate and pipe most of the carbon dioxide (CO_2) formed in the gasification process to the associated Enhanced Oil Recovery (EOR) component, which is owned and operated by Occidental of Elk Hills, Inc (OEHI). The remaining CO_2 would be used in the onsite fertilizer manufacturing facility. This project would capture about 90 percent of the CO_2 in the synthetic gas produced in the gasifier, or approximately 3 million tons per year. Of this amount, 2.6 million tons per year of CO_2 would be sequestered through EOR operations and 0.4 million tons per year of CO_2 would be used in fertilizer manufacturing.

HECA's likely actual operating profile is not known; the applicant has described the facility's expected operation using more than one potential operating profile. Different operating profiles may need to be evaluated to determine which set of operating conditions represent worst case impacts. Some operating profiles may result in the facility not complying with certain regulatory requirements. For example, a profile provided by the applicant indicated reduced electricity production for eight hours each day, reducing the portion of the hydrogen-rich gas used to produce electricity and increasing that used to produce fertilizer. Under this operating profile, the project may not comply with California's Greenhouse Gases (GHG) Emission Performance Standard (EPS), as described more fully below. Even with this reduced electricity production, HECA would be operated at a capacity factor of 85 percent, roughly equal to that of the Intermountain Power Plant in Utah or the Argus Cogeneration Plant in Trona, California, both of which use coal.

Electricity is produced by operation of inter-connected generation resources. The operation of one power plant affects the operation of other power plants in the

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[1] A comprehensive acronym list is provided at the end of this section.

[2] These generation values represent the applicant's latest gross and net megawatt estimates and are based on specific operating and ambient conditions, where these generation values would occur under average annual ambient conditions. The net megawatt estimate includes the fertilizer plant's parasitic load and its associated small amount of generation but does not include the air separation unit's parasitic load, and when considering this item the net generation value drops to approximately 160 MW.

interconnected system. HECA, if accompanied by permanent sequestration, would affect the overall electricity system operation and GHG emissions in several ways. HECA:

- would, upon attaining mature operations, provide base load generation with emissions that are lower than other fossil fuel fired power plants except for the most efficient natural gas fired combined cycle facilities.
- would facilitate reductions in the import of electricity from specific power plants located out-of-state, such as coal-fired power plants with long-term contracts that have higher GHG emissions per megawatt hour, as well as imports from unspecified sources which are assumed to have higher GHG emissions per megawatt hour by the California Air Resources Board,
- could facilitate the retirement of aging fossil-fired power plants that use once-through cooling by providing necessary replacement capacity to meet reserve margin requirements in Southern California.
- would use a California petroleum refinery by-product, petroleum coke, as a fuel feedstock source which would reduce the transportation GHG emissions associated with international export of this material.
- would enable additional domestic petroleum production which would reduce the need for petroleum imports to meet California's ongoing petroleum oil product demand and would reduce associated petroleum oil transportation GHG emissions.
- would be operated in conjunction with an enhanced oil recovery/CO_2 sequestration project in the Elk Hills Oil Field (EHOF) that would be the third largest carbon capture and storage (CCS) project in the world, after La Barge in Wyoming and Gorgon in Australia. The demonstration of CCS from a large scale coal-fired power plant is the reason why this project has been selected to receive funding under the Department of Energy's (DOE) Clean Coal Power Initiative (CCPI).
- would be a polygeneration plant that would use a portion of the hydrogen produced from the gasification of the fuel to make fertilizer products to increase the electrical generation flexibility of the facility. This would provide HECA with the ability to reduce generation when necessary by approximately 45 percent to operate with some flexibility/dispatchability as needed depending on electrical load demand.
- would produce fertilizer products within an agricultural valley that could displace GHG emissions from their manufacture at other existing or new sources and reduce associated transportation emissions from fertilizer manufacture that occurs outside the San Joaquin Valley.

These system impacts, and the other GHG emission effects of the proposed project, would provide energy and capacity to California and would also lead to a net reduction of GHG emissions considering the other sectors affected, such as petroleum coke fuel transport, petroleum production and imports, and fertilizer transportation. Thus, staff concludes that the proposed project would result in a cumulative overall reduction in

California’s GHG emissions, would not worsen current conditions, and would not result in impacts that are cumulatively significant.

Staff concludes that the short-term minor emission of GHG during construction would be sufficiently reduced by “best practices” and would be more than offset by the system-wide GHG emission reductions during operation and would, therefore, not result in significant, adverse impacts.

The project could meet the EPS that applies to utility purchases of base load power from power plants (Title 20, California Code of Regulations, section 2900 et seq.), if the majority of HECA’s CO_2 emissions are permanently sequestered depending on the operating profile of the facility. However, the potential range of facility operating profiles is uncertain at this time, so staff cannot at this time make a final determination regarding compliance with the EPS. Staff is in the process of designing conditions of certification that would enforce the carbon sequestration that is necessary for this project to comply with this regulation. Staff has provided preliminary conditions of certification that outline the type of requirements that will be recommended by staff; however, significant additional detail will be added to these conditions in the FSA and additional conditions may be required for the facility to comply with the EPS so they could sell electricity to a California electric utility.

The United States Environmental Protection Agency has promulgated regulations for the permitting of major GHG emission sources and GHG emission reporting, and the California Air Resources Board has promulgated regulations for the California Global Warming Solutions Act of 2006 (AB 32 Núñez, Statutes of 2006, Chapter 488, Health and Safety Code sections 38500 et seq.) and has recently implemented a GHG emissions cap and trade regulation that has been designed to help achieve the state’s GHG emission reduction goals. The San Joaquin Valley Air Pollution Control District has found in its Preliminary Determination of Compliance that the project complies with all laws, ordinances, regulations and standards, including federal GHG emissions permitting requirements. The proposed project would also have to comply with the state cap and trade regulations, federal GHG emission source permitting, and federal and state GHG emissions reporting requirements.

In summary staff believes that with appropriate conditions of certification that staff is currently designing and that will be provided in the Final Staff Assessment/Final Environmental Impact Statement (FSA/FEIS), HECA would not create significant greenhouse gas impacts or geologic impacts and would comply with all laws, ordinances, regulations, and standards (LORS).

UNRESOLVED AREAS RELATING TO CARBON SEQUESTRATION AND GREENHOUSE GASES

Greenhouse Gases Analysis

Staff believes that the greenhouse gas emissions from HECA and the Occidental of Elk Hills, Inc. Enhanced Oil Recovery component should be able to meet all regulatory requirements, and staff is in the process of designing conditions of certification that will ensure carbon sequestration and compliance with the EPS. However, staff requires that prior to publication of the Final Staff Assessment/Final Environmental Impact Statement the applicant shall enter into a binding contract with Occidental of Elk Hills, Inc. that:

- Identifies the responsibilities of each party to demonstrate and document permanent sequestration of the supplied CO_2.
- Documents Hydrogen Energy California's rights to the entire CO_2 sequestration emissions reductions as necessary for SB 1368 EPS and other regulatory compliance.
- Clearly states that the CO_2 sequestration emissions reductions shall not be used for any other purpose than providing for the compliance obligation needs for HECA.
- This contract shall also require Occidental of Elk Hills, Inc. to provide a Carbon Dioxide Emissions Sequestration Plan to the Energy Commission for review and approval as detailed under the preliminary staff Condition of Certification **GHG-3**.

This contract is required before staff can finalize its recommendation for the project in the Final Staff Assessment/Final Environmental Impact Statement.

Staff's findings are contingent on the energy generation and consumption assumptions and operating profile that staff is currently using. However, staff has identified issues with those values, such as changes in the gas turbine gross generation rating. Staff has requested a complete energy balance for the HECA facility that includes all sources of generation and consumption, including the air separation unit. The applicant has not yet provided that information. This information is required before staff can finalize its regulatory compliance analysis and determine its recommendation for the project.

Carbon Sequestration Geology Analysis

The presence of the numerous surface and subsurface faults give reason to staff for concern that the increased pressures associated with the injection of the CO_2 can cause increased stresses on faults that can cause those faults to slip and the apertures to dilate.

Despite several attempts by staff to get site specific geologic information from the applicant such information was not provided. Therefore, staff had to rely on information from a nearby oil field that is believed to have similar characteristics as the EHOF. Using geologic data from the nearby oil field, staff has concluded that there are no unresolved geology issues that would threaten the integrity of the proposed CO_2/water injection EOR component at the EHOF. See the **Geology and Paleontology** section of this Preliminary Staff Assessment/Draft Environmental Impact Statement (PSA/DEIS) for more information on earthquake faults in the region and potential impacts that would be expected from the project, if constructed.

Based on information presented in a number of workshops between staff and the applicant as well as representatives from OEHI, staff concludes that it is feasible to inject the projected amount of CO_2 over 20 years into the Stevens reservoir. OEHI estimates that the amount of CO_2 that is estimated to be sequestered by the EOR operations after 20 years would fill only about 5 percent of the usable pore space of the reservoir. This leaves a very large volume of the reservoir available for further injection and storage in the event that the injection activities continue beyond the projected lifetime of HECA. Given the geologic lifetime of natural CO_2 domes, and many long-lasting CO_2 injection projects, it is likely that the CO_2 would be stored permanently in the EHOF. This is assuming that existing production wells as well as abandoned wells are rehabilitated to meet specifications for injection wells and monitoring wells associated with injection of CO_2 for sequestration purposes. Additionally, the CO_2 filled reservoirs would be 5,000 to 7,000 feet below the surface. The formations where the CO_2 would be stored are separated from the surface by other formations including thick and continuous shale layers. These formations offer a tight lid to prevent the stored CO_2 from leaking through the formation to the surface. The only likely pathways for leakage that remain are therefore the well borings where leakage can take place through the casings themselves or through the annular space between the casings and the formation.

Underground injection of fluids and gases is known to cause increased levels of microscopic seismic activities. As discussed in the Geology and Paleontology section, the maximum anticipated peak acceleration produced by the injection is on the order of 0.01 g, which is more than an order of magnitude less intense than site accelerations associated with maximum credible earthquakes on major faults mapped in the vicinity of the project site. Also, as discussed in the **Geology and Paleontology** section, any additional seismic event resulting from proposed CO_2 injection is not expected to exceed a magnitude 4 earthquake, a magnitude that can be felt by a human observer but is incapable of causing structural damage to facilities and buildings. Therefore, injection of the CO_2 is not expected to result in significant impacts in terms of increased seismic activity.

The enhanced oil recovery component associated with the injection of the CO_2 would include a monitoring program to ensure that there is no geologic leakage of the injected CO_2 and that after the field is retired the wells will be properly plugged and abandoned in accordance with the requirements for Class VI Underground Injection Control (UIC) regulation, as specified in the proposed conditions of certification. There are many oil production wells in the formation above the Reef Ridge formation where the carbon is planned to be injected. According to the Monitoring, Reporting, and Verification (MRV) plan that was submitted by OEHI, the prospective injector of the $CO_{2,}$ those wells are equipped with a sophisticated network of monitoring equipment that is centrally monitored and controlled. The monitoring system in those wells would include monitoring for CO_2 leakage and would offer an added level of monitoring to detect that any leaks through the formation, though unlikely, would be detected early and would be dealt with appropriately. Staff further concludes that the injection pressures required for this project are below pressures required to fracture the formation and would not induce significant seismic events.

In such a vast operation with hundreds of wells for injection and production, let alone the thousands of well bores that abound in the site for different purposes and at varying depths of penetration, leaks are prone to happen at some of the well bores. Tier 4 of the monitoring is for dealing with leaks when they are detected. OEHI's proposed procedure to deal with detected leaks involves immediate isolation of the leaking well, depressurizing the zone, and repairing the leaking well. While most likely the repair process would involve injecting a plug of cement to seal the place of the leak, this type of leak is not always accessible to inject a plug of cement. In case the leaking spot in a well is not accessible for plugging, OEHI will have to abandon that well and drill another well. OEHI stated that standard procedures would be followed to detect leaks in a well bore and follow standard procedures to repair the leak. In the event a leak is detected, which has a low-probability of occurrence; OEHI would first depressurize the reservoir at the location of the leak and then isolate the leaking zone so that repairs can be made.

OEHI has not provided detailed information on the approach it would apply to assess the amounts of CO_2 leaked to the surface. Staff therefore cannot assess the effectiveness of the approach. OEHI should decide on one or more approaches to be used for assessing the amounts of fugitive CO_2 ahead of the detection of leaks and provide details of those approaches to staff for assessment. Without this information, staff cannot conclude that HECA would comply with the state's EPS.

GHG EMISSIONS ANALYSIS – William Walters

INTRODUCTION

The generation of electricity using fossil fuels produces air emissions known as greenhouse gases in addition to the criteria air pollutants that have been traditionally regulated under the federal and state Clean Air Acts (CAA). California is actively pursuing policies to reduce GHG emissions that include adding non-GHG emitting renewable generation resources to the system. The California-regulated greenhouse gases include CO_2, nitrous oxide (N_2O), methane (CH_4), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFC), and perflurocarbons (PFC).

GHGs have wide ranging global warming potentials (GWP). Global warming potential is a relative measure, compared to CO_2, of a compound's residence time in the atmosphere and ability to warm the planet. CO_2 emissions are the most common of these emissions; as a result, even though the other GHGs may have a greater impact on climate change on a per-unit basis, GHG emissions are often "normalized" in terms of metric tons of CO_2-equivalent (MT CO2E) for simplicity. By convention, CO_2 is assigned a GWP of 1. In comparison, CH_4 has a GWP of 21, which means that it has a global warming effect 21 times greater than CO_2 on an equal-mass basis. The CO2E for a source is calculated by multiplying each GHG emission by its GWP, and adding the results together to produce a single, combined emission rate representing all GHGs.

GHG emissions include both direct and indirect emissions. Direct emissions are those that would be emitted from sources owned or controlled by a project applicant and generated directly as a result of project actions. Direct emissions from construction activities include GHG emissions generated from construction equipment and vehicles. Direct emissions from operating activities include GHG emissions generated from stationary sources, and vehicle trips. Indirect GHG emissions sources can take many forms, such as electricity usage or waste disposal, depending on the type of project.

GHG emissions are not criteria pollutants. Since the impact of the GHG emissions from a power plant's operation has global, rather than local effects, those impacts should be assessed not only by analysis of the plant's emissions, but also in the context of the operation of the entire electricity system of which the plant is an integrated part. Furthermore, the impact of the GHG emissions from a power plant's operation should be analyzed in the context of applicable GHG laws and policies, such as Assembly Bill (AB) 32, California's Global Warming Solutions Act (Stats. 2006, ch. 488.), the EPS, and Prevention of Serious Deterioration (PSD) permitting requirements.

GLOBAL CLIMATE CHANGE – DOE

Climate Change

The human and natural causes of climate change and the impacts of climate change are global in scope. GHG emissions, which are believed to contribute to climate change, do not remain localized, but become dispersed throughout the Earth's atmosphere. Therefore, this analysis cannot separate the particular contribution of HECA's and OEHI's GHG emissions to regional or global climate change from the many other past, present, and reasonably foreseeable projects that have produced or would produce or mitigate GHG emissions. Rather, this review focuses on the cumulative effects of GHG emissions and climate change from a global perspective.

Background

A worldwide environmental issue is the likelihood of changes in the global climate as a consequence of global warming produced by increasing atmospheric concentrations of GHGs (IPCC 2007c). The atmosphere allows a large percentage of incoming solar radiation to pass through to the Earth's surface, where it is converted to heat energy (infrared radiation) that is more readily absorbed by GHGs than the incoming solar radiation. The heat energy absorbed near the Earth's surface increases the temperature of air, soil, and water.

GHGs include water vapor, CO_2, methane, nitrous oxide, ozone (O_3), and several chlorofluorocarbons. Although GHGs constitute a small percentage of the Earth's atmosphere, they are responsible for its heat-trapping properties. Water vapor, a natural component of the atmosphere, is the most abundant GHG, but its atmospheric concentration is driven primarily by changes in the Earth's temperature. As such, water vapor can amplify the effects of other GHGs such as CO_2. The second-most abundant GHG is CO_2, which remains in the atmosphere for long periods of time. Due to human activities, atmospheric CO_2 concentrations have increased by approximately 35 percent over preindustrial levels. Fossil fuel burning, specifically from power production and transportation, is the primary contributor to increasing concentrations of CO_2 (IPCC

2007c). In the U.S., stationary CO_2 sources include energy facilities (such as coal and natural gas power plants) and industrial facilities. Industrial processes that emit these gases include cement manufacture, limestone and dolomite calcination, soda ash manufacture and consumption, and aluminum production (Energy Information Administration 2009). In addition, industrial and agricultural activities release GHGs other than CO_2 -- notably methane, NOx, O_3, and chlorofluorocarbons -- to the atmosphere, where they can remain for long periods of time.

In the preindustrial era (before 1750 A.D.), the concentration of CO_2 in the atmosphere appears to have been 275 to 285 ppm (IPCC 2007c). In 1958, C.D. Keeling and others began measuring the concentration of atmospheric CO_2 at Mauna Loa in Hawaii (Keeling et al. 1976). The data collected by Keeling's team and others since then indicate that the amount of CO_2 in the atmosphere has been steadily increasing from approximately 316 ppm in 1959 to 396.8 ppm in February 2013 (National Oceanic and Atmospheric Administration 2010, 2013). In addition, the Fourth U.S. Climate Action Report concluded, in assessing current trends, that CO_2 emissions increased by 20 percent from 1990 to 2004, while methane and nitrous oxide emissions decreased by 10 percent and 2 percent, respectively. This increase in atmospheric CO_2, methane and nitrous oxides is attributed almost entirely to human activities.

Impacts of Greenhouse Gases on Climate

Climate is defined as the average weather of a region, or more rigorously as the statistical description of a region's weather in terms of the means and variability of relevant parameters over time periods ranging from months to thousands of years. The relevant parameters include temperature, precipitation, wind, and dates of meteorological events such as first and last frosts, beginning and end of rainy seasons, and appearance and disappearance of pack ice. Because GHGs in the atmosphere absorb energy that would otherwise radiate into space, the possibility that human-caused emissions of these gases could result in warming that might eventually alter climate was recognized soon after the data from Mauna Loa and elsewhere confirmed that the atmosphere's content of CO_2 was steadily increasing (IPCC 2007c; National Oceanic and Atmospheric Administration 2010).

Changes in climate are difficult to detect because of the natural and complex variability in meteorological patterns over long periods of time and across broad geographical regions. There is much uncertainty regarding the extent of global warming caused by human-induced GHG emissions, the climate changes this warming has or will produce, and the appropriate strategies for stabilizing the concentrations of GHGs in the atmosphere. The World Meteorological Organization and United Nations Environment Programme established the IPCC to provide an objective source of information about global warming and climate change, and IPCC's reports are generally considered to be an authoritative source of information on these issues.

According to the IPCC fourth assessment report, "[w]arming of the climate system is unequivocal, as is now evident from observations of increases in global average air and ocean temperatures, widespread melting of snow and ice, and rising global average sea level" (IPCC 2007d). The IPCC report finds that the global average surface temperature has increased by approximately 0.74 degrees Celsius in the last 100 years, global average sea level has risen approximately 150 millimeters over the same period, and cold days, cold nights, and frosts over most land areas have become less frequent during the past 50 years. The report concludes that most of the temperature increases since the middle of the twentieth century are “very likely due to the observed increase in anthropogenic [GHG] concentrations.”

The 2007 report estimates that, at present, CO_2 accounts for approximately 77 percent of the global warming potential attributable to human-caused releases of GHGs, with most (74 percent) of this CO_2 coming from the combustion of fossil fuels. Although the report considers a variety of future scenarios regarding GHG emissions, CO_2 would continue to contribute more than 70 percent of the total warming potential under all of the scenarios. The IPCC therefore believes that further warming is inevitable, but that this warming and its effects on climate could be mitigated by stabilizing the atmosphere’s concentration of CO_2 through the use of 1) “low-carbon technologies” for power production and industrial processes, 2) more efficient use of energy, and 3) management of terrestrial ecosystems to capture atmospheric CO_2 (IPCC 2007d).

Environmental Impacts of Climate Changes

The IPCC and the U.S. Climate Change Science Program have examined the potential environmental impacts of climate change at global, national, and regional scales. The IPCC report states that, in addition to increases in global surface temperatures, the impacts of climate change on the global environment may include:

- more frequent heat waves, droughts, and fires;
- rising sea levels and coastal flooding;
- melting glaciers, ice caps, and polar ice sheets;
- more severe hurricane activity and increases in frequency and intensity of severe precipitation;
- spread of infectious diseases to new regions;
- loss of wildlife habitats; and
- heart and respiratory ailments from higher concentrations of ground-level O_3 (IPCC 2007d).

On a national scale, average surface temperatures in the U.S. have increased, with the last decade being the warmest in more than a century of direct observations (U.S. Climate Change Science Program 2008). Impacts on the environment attributed to climate change that have been observed in North America include:

- extended periods of high fire risk and large increases in burned areas;
- increased intensity, duration, and frequency of heat waves;
- decreased snowpack, increased winter and early spring flooding potentials, and reduced summer stream flows in the western mountains; and

- increased stress on biological communities and habitat in coastal areas (IPCC 2007d).

On a regional scale, there is greater natural variability in climate parameters that makes it difficult to attribute particular environmental impacts to climate change (IPCC 2007d). However, based on observational evidence, there is likely to be an increasing degree of impacts such as coral reef bleaching, loss of specific wildlife habitats, reductions in the area of certain ecosystems, and smaller yields of major cereal crops in the tropics (IPCC 2007d). For the northern hemisphere, regional climate change could affect physical and biological systems, agriculture, forests, and amounts of allergenic pollens (IPCC 2007d).

HECA's and OEHI's Potential Greenhouse Gas Emissions

The HECA component and OEHI component of the project, jointly, would demonstrate the technical and economic feasibility of capturing a high percentage of CO_2 produced by the use of coal and petcoke mixture as a feedstock in an IGCC electricity and chemicals production plant. Carbon in the coal would be converted mostly into syngas components: CO_2, CO, and small amounts of COS and other carbon forms. The polygeneration plant's water-gas shift reactor and acid gas removal units would convert most of the CO and COS in the syngas into CO_2. Approximately 92 percent of the carbon in the fuel feedstock would be captured as CO_2, and as much as 6 percent of this captured CO_2, or 5 percent of the total CO_2 in the fuel feedstock, may be released annually through the CO_2 Vent (HECA 2012s).

Carbon from fuel used at HECA's plant would take one of three primary pathways:

1. Approximately 8 percent of the coal and petcoke fuel's carbon would not be captured and would pass through as CO_2 or would be converted to CO_2 in the gas turbine and duct burner as small amounts of carbon-bearing compounds are fully oxidized. The CO_2 emission to the atmosphere, including the CO_2 Vent emissions, from the carbon in the petcoke and coal would amount to approximately 0.44 million MT per year as permitted during normal plant operations, or 11 million MT over a 25-year life of the plant. A small amount of carbon would go into slag and particulates. Preferably the slag would be sold for beneficial uses; alternatively it would be sent to a landfill.
2. Approximately 92 percent of the fuel's carbon would be captured as CO_2. Of the captured and unvented CO_2, approximately 84 percent would be sold to OEHI's project with an expectation of permanent sequestration of almost all of this CO_2. The CO_2 amount that would be sold would range from approximately 2.5-3.0 million MT per year during normal plant operations or 75-90 million MT over the 25-year life of the plant, depending on electricity and urea demand.
3. Of the captured and unvented CO_2, approximately 16 percent would be used to make urea and urea ammonium nitrate to be sold on the national market with no expectation of permanent sequestration of this CO_2. This CO_2 is assumed to remain in the surface and near surface environment but would benefit the production of crops and vegetation. The CO_2 captured in the urea product would amount to

approximately 0.53 million MT per year during normal plant operations or 13 million MT over the 25-year life of the plant, based on minimum and maximum capacities.

The electric power sector in the U.S. releases approximately 2.40 billion MT of CO_2 annually; U.S. coal-fired power plants account for 1.97 billion MT of that amount (EPA 2010). Globally, 49 billion MT of CO_2-equivalent anthropogenic GHGs are emitted annually, with fossil fuel combustion contributing approximately 29 billion MT of that amount. Annual emissions of CO_2 from the proposed project would add to these emissions.

It is likely that new fossil fuel-based electricity generating plants will be built in the United States. Although renewable energy projects have been proposed and are being developed in California, as they are in other parts of the country, the California ISO, CPUC and the Energy Commission have projected demand for replacement generating capacity that is greater than the projected capacity of new renewable sources. Similar projections have been made in other regions of the U.S. Renewable sources (wind and solar) are intermittent, requiring additional base-load to balance electric power supplies.

Although a DOE decision to contribute funding to HECA would not make it "reasonably foreseeable," within the meaning of 40 C.F.R. § 1508.7 that future fossil fuel-based power plants will incorporate carbon capture, successful construction and operation of HECA could demonstrate the feasibility of incorporating the capture of CO_2, making it more likely that it would be incorporated into new fossil fuel power plants. Should HECA demonstrate the feasibility of utility-scale electric power generation with carbon capture, it could result in the incorporation of carbon capture in new power plants, with resulting reductions in CO_2 emissions from new electricity generating capacity built in the future.

Because HECA is designed for over 90 percent carbon capture, it represents a step toward reducing GHG emissions from both coal and natural gas power plants.

GLOBAL CLIMATE CHANGE AND CALIFORNIA– William Walters

Worldwide, with the exception of 1998, over the past 132-year record the nine warmest years all have occurred since 2000, with the two hottest years on record being 2010 and 2005 (NASA 2013). According to "The Future Is Now: An Update on Climate Change Science Impacts and Response Options for California," an Energy Commission document, the American West is heating up faster than other regions of the United States (CEC 2009a). The California Climate Change Center (CCCC) reports that, by the end of this century, average global surface temperatures could rise by 4.7°F to 10.5°F due to increased GHG emissions.

The accumulation of GHGs in the atmosphere regulates the earth's temperature. Without these natural GHGs, the earth's surface would be approximately 61°F (34°C) cooler (CalEPA 2006); however, emissions from fossil fuel combustion for activities such as electricity production and vehicular transportation have elevated the concentration of GHGs in the atmosphere above natural levels. ARB estimated that the mobile source sector accounted for approximately 38 percent of the GHG emissions generated in California in 2009, while the electricity generating sector accounted for approximately 23 percent of the 2009 California GHG emissions inventory with just more than half of that from in-state generation sources (ARB 2011).

The Fourth U.S. Climate Action Report concluded, in assessing current trends, that CO_2 emissions increased by 20 percent from 1990 to 2004, while methane and nitrous oxide emissions decreased by 10 percent and 2 percent, respectively. The Intergovernmental Panel on Climate Change (IPCC) constructed several emission trajectories of GHGs needed to stabilize global temperatures and climate change impacts. It concluded that stabilization of GHGs at 450 ppm carbon dioxide equivalent concentration is required to keep the global mean warming increase below 3.8°F (2.1°C) from year 2000 base line levels (IPCC 2007a).

GHGs differ from criteria pollutants in that GHG emissions from a specific project do not cause direct adverse localized human health effects. Rather, the direct environmental effect of GHG emissions is the cumulative effect of an overall increase in global temperatures, which in turn has numerous indirect effects on the environment and humans. The impacts of climate change include potential physical, economic and social effects. These effects could include inundation of settled areas near the coast from rises in sea level associated with melting of land-based glacial ice sheets, exposure to more frequent and powerful climate events, and changes in suitability of certain areas for agriculture, reduction in Artic sea ice, thawing permafrost, later freezing and earlier break-up of ice on rivers and lakes, a lengthened growing season, shifts in plant and animal ranges, earlier flowering of trees, and a substantial reduction in winter snowpack (IPCC 2007b). For example, current estimates include a 30 to 90 percent reduction in snow pack in the Sierra Nevada mountain range. Current data suggest that in the next 25 years, in every season of the year, California could experience unprecedented heat, longer and more extreme heat waves, greater intensity and frequency of heat waves, and longer dry periods. More specifically, the CCCC predicted that California could witness the following events (CCCC 2006):

- Temperature rises between 3 and 10.5 ºF
- 6 to 20 inches or greater rise in sea level
- 2 to 4 times as many heat-wave days in major urban centers
- 2 to 6 times as many heat-related deaths in major urban centers
- 1 to 1.5 times more critically dry years
- Losses to mountaintop snowpack and water supply (e.g., according to the CCCC, Sierra Nevada snowpack could be reduced by as much as 20 to 40 percent by 2100 [CEC 2009])
- 25 to 85 percent increase in days conducive to ozone formation
- 3 to 20 percent increase in electricity demand
- 10 to 55 percent increase in the risk of wildfires

There is general scientific consensus that climate change is occurring and that human activity contributes in some measure (perhaps substantially) to that change. Man-made emissions of greenhouse gases, if not sufficiently curtailed, are likely to contribute further to continued increases in global temperatures. Indeed, the California Legislature finds that "[g]lobal warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California" (Cal. Health & Safety Code, sec. 38500, division 25.5, part 1).

The state has demonstrated a clear willingness to address global climate change (GCC) through research, adaptation[3], and GHG emission reductions. In that context, staff evaluates the GHG emissions from the proposed project, presents information on GHG emissions related to electricity generation (see "**Electricity System GHG Impacts**" below), and describes the applicable GHG policies and programs.

In April 2007, the U.S. Supreme Court held that GHG emissions are pollutants within the meaning of the CAA. In reaching its decision, the Court also acknowledged that climate change results, in part, from anthropogenic causes (Massachusetts et al. v. Environmental Protection Agency 549 U.S. 497, 2007). The Supreme Court's ruling paved the way for the regulation of GHG emissions by USEPA under the CAA.

In response to this Supreme Court decision, on December 7, 2009 the USEPA Administrator signed two distinct findings regarding GHGs under Section 202(a) of the CAA:

- Endangerment Finding: That the current and projected concentrations of the GHGs in the atmosphere threaten the public health and welfare of current and future generations; and
- Cause or Contribute Finding: That the combined emissions of GHGs from new motor vehicles and new motor vehicle engines contribute to the GHG pollution which threatens public health and welfare.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

In December 2009, the U.S. Environmental Protection Agency (U.S. EPA) declared that greenhouse gases (GHGs) threaten the public health and welfare of the American people (the so-called "endangerment finding"). Regulating GHGs at the federal level is required by PSD Program for sources that exceed 100,000 tons per year of CO2E emissions, or more than 75,000 tons if the stationary source is a major source for a non-GHG regulated pollutant. Additionally, federal rules that became effective December 29, 2009 (40 CFR 98) require federal reporting of GHG emissions. As federal rulemaking continues to evolve, staff at this time focuses on analyzing the ability of the project to comply with existing federal- and state-level policies and programs for GHGs.

[3] While working to understand and reverse global climate change, it is prudent to also adapt to potential changes in the state's climate (for example, changing rainfall patterns).

HECA's GHG emissions exceed the PSD permitting trigger level and HECA is subject to GHG PSD permitting, which is a part of the air permit that the San Joaquin Valley Air Pollution Control District (SJVAPCD) is currently completing for HECA. Conditions in the SJVAPCD's Preliminary Determination of Compliance (PDOC), released for a 45-day public comment period on February 7, 2013 that was later extended to an even longer comment period, related to the GHG PSD permitting are included in this Preliminary Staff Assessment/Draft Environmental Impact Statement (PSA/DEIS), and any changes to those conditions that are included in the SJVAPCD Final Determination of Compliance (FDOC) will be included in the Final Staff Assessment/Final Environmental Impact Statement (FSA/FEIS). It is also likely that the OEHI CO_2 EOR component, itself or as part of the larger Occidental operating complex, would also require a PSD permit for GHG emissions prior to construction because the CO_2 emissions without the regulated recycling of the produced CO_2 would easily exceed the CO_2 PSD emissions permitting trigger level.

In 1998, the Energy Commission identified a range of strategies to prepare for an uncertain climate future, including a need to account for the environmental impacts associated with energy production, planning, and procurement (CEC 1998, p.5). In 2003, the Energy Commission recommended that the state require reporting of GHGs or global climate change[4] (GCC) emissions as a condition of state licensing of new electric generating facilities (CEC 2003, IEPR p. 42). In 2006, California enacted the California Global Warming Solutions Act of 2006 (AB 32). It requires the ARB to adopt standards that will reduce statewide GHG emissions to statewide GHG emissions levels in 1990, with such reductions to be achieved by 2020. To achieve this, ARB has a mandate to define the 1990 emissions level and achieve the maximum technologically feasible and cost-effective GHG emission reductions to meet this requirement. Executive Order S-3-05 also requires ARB to plan for further GHG emissions reductions to achieve an 80 percent reduction from 1990 GHG emissions by the year 2050.

The ARB adopted early action GHG reduction measures in October 2007, adopted mandatory reporting requirements and the 2020 statewide target in December 2007, and adopted a statewide scoping plan in December 2008 to identify how emission reductions will be achieved from major sources of GHG via regulations, market mechanisms, and other actions. ARB adopted regulations implementing cap-and-trade regulations on December 22, 2011 and ARB staff continues to develop and implement regulations to refine key elements of the GHG reduction measures to improve their linkage with other GHG reduction programs. The ARB has not yet determined approved quantification methods that ensure that the emissions reductions from geologic sequestration are real, permanent, quantifiable, verifiable, and enforceable.

The California Climate Action Team produced a report to the Governor (CalEPA 2006) which included many examples of strategies that the state could pursue to reduce GHG emissions in California, in addition to several strategies that had been recommended by

[4] Global climate change is the result of greenhouse gases, or air emissions with global warming potentials, affecting the global energy balance, and thereby, climate of the planet. The term greenhouse gases (GHG) and global climate change (GCC) gases are used interchangeably.

the Energy Commission and the Public Utilities Commission. Improvements in transportation energy efficiency (fuel economy) and land use planning and alternatives to petroleum-based fuels are slated to provide substantial reductions by 2020 (CalEPA 2006). Their third biennial report, published in December 2010 and required by Executive Order S-3-05, is the most recent report addressing actions that California could take to reduce GHG emissions (CalEPA 2010).

The scoping plan approved by ARB in December 2008 builds upon the overall climate change policies of the Climate Action Team reports and includes recommended strategies to achieve the goals for 2020 and beyond. Some strategies focus on reducing consumption of petroleum across all areas of the California economy. The scoping plan includes a 33 percent Renewables Portfolio Standard (RPS), aggressive energy efficiency targets, and a cap-and-trade program that includes the electricity sector (ARB 2008). Senate Bill 2 (Simitian, Chapter 1, Statutes of 2011-12) expresses the intent of the California Legislature to have 33 percent of California's electricity supplied by renewable sources by 2020. Mandatory compliance with cap-and-trade requirements commenced on January 1, 2012, and enforcement began in January 2013.

SB 1368[5], enacted in 2006, and regulations adopted by the Energy Commission and the Public Utilities Commission pursuant to Title 20, California Code of Regulations, section 2900 et seq. prohibit California utilities from entering into long-term commitments with any base load facilities that exceed the EPS of 0.5 metric tonnes CO_2 per megawatt-hour[6] (equivalent to 1,100 pounds CO_2/MWh). Specifically, the EPS applies to power from new power plants, new investments in existing power plants, and new or renewed contracts with terms of five years or more, including contracts with power plants located outside of California, where the power plant in question is "intended and designed" to operate as a base load power plant.[7] *Base load* units are defined as units that operate at a capacity factor higher than 60 percent. If a project, in-state or out of state, plans to sell electricity to a California utility under a long-term contract (five years or more), that utility will have to demonstrate that the project meets the EPS. Compliance with the EPS is determined by dividing the annual average carbon dioxide emissions by the annual average net electricity production in MWh. This determination is based on capacity factors, heat rates, and corresponding emissions rates that reflect the *expected* operations of the power plant and not on full load heat rates [Title 20, California Code of Regulations, §2903(a)]. HECA is expected to operate continuously, outside of process upsets and annual maintenance; even if the facility were to maximize urea fertilizer manufacturing it would be expected to operate at a capacity factor greater than 60 percent. Accordingly, it would have to comply with the EPS in order for California utilities to acquire an ownership share in the project, or to purchase energy from it under a long-term contract.

[5] Public Utilities Code § 8340 et seq.

[6] The Emission Performance Standard only applies to carbon dioxide, and does not include emissions of other greenhouse gases converted to carbon dioxide equivalent.

[7] See Rule at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/64072.htm

SB1018 (Stats. 2012, ch. 39.) establishes new legislative oversight and controls over the Air Resources Board including: the creation of a separate expenditure fund for proceeds from the auction or sale of GHG allowances pursuant to the market-based compliance mechanism (the cap-and-trade program); the establishment of a separate Cost of Implementation Fee account for oversight and tracking of funds; oversight of actions taken on behalf of the State of California related to market-based compliance and auctions, specific to the Western Climate Initiative (WCI) and WCI, Inc.; and provides for return of certain funds to ratepayers of Investor Owned Utilities from funds related to the auction or sale of allowances.

If built, HECA would be required to participate in California's greenhouse gas cap-and-trade program. This cap-and-trade program is part of a broad effort by the State of California to reduce GHG emissions as required by AB32, which is being implemented by ARB. Market participants such as HECA would be required to report their GHG emissions and to obtain GHG emissions allowances (and offsets) for those reported emissions by purchasing allowances from the capped market and offsets from outside the AB32 program. Thus, HECA, as a GHG cap-and-trade participant, would be consistent with California's landmark AB 32 Program, which is a statewide program coordinated with a region wide WCI program to reduce California's GHG emissions to 1990 levels by 2020.

The applicable LORS for HECA and the associated OEHI CO_2 EOR component are both detailed below.

HECA

The following federal, state, and local laws and policies in **Carbon Sequestration and Greenhouse Gas Emissions Table 1** pertain to the control and mitigation of HECA's greenhouse gas emissions. Staff's analysis examines the proposed project's compliance with these requirements.

OEHI CO_2 EOR Component

The following federal, state, and local laws and policies in **Carbon Sequestration and Greenhouse Gas Emissions Table 2** pertain to the control and mitigation of the OEHI CO_2 EOR component as it relates to the sequestration of HECA's CO_2 emissions. Because carbon sequestration is necessary for regulatory compliance as explained further below, and because it is considered part of the proposed project, staff's analysis examines the proposed OEHI CO_2 EOR component's emissions in determining HECA's compliance with these requirements.

Carbon Sequestration and Greenhouse Gas Emissions Table 1
HECA
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	
40 Code of Federal Regulations (CFR) Parts 51, 52, 70 and 71	This rule "tailors" GHG emissions to PSD and Title V permitting applicability criteria. A new stationary source that emits more than 100,000 tons per year (TPY) of GHGs is considered to be a major stationary source subject to PSD requirements. This project would trigger the 100,000 TPY PSD threshold. SJVAPCD has been granted authority to enforce this regulation.
40 Code of Federal Regulations (CFR) Part 98	This rule requires mandatory reporting of GHG emissions for facilities that emit more than 25,000 metric tons of CO_2 equivalent emissions per year. This requirement is triggered for this project.
State	
California Global Warming Solutions Act of 2006, AB 32 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)	This act requires the ARB to enact standards that will reduce GHG emissions to 1990 levels by 2020. Electricity production is a covered sector under AB 32.
California Code of Regulations, tit. 17, Subchapter 10, Article 2, sections 95100 et. seq.	These ARB regulations implement mandatory GHG emissions reporting as part of the California Global Warming Solutions Act of 2006 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)
California Code of Regulations, tit. 17, Subchapter 10, Article 5, sections 95800 et. seq. (Cap and Trade)	These ARB regulations cap greenhouse gas emissions from specified California emission sources, including power plants that emit more than 25,000 metric tons of CO_2 equivalent emissions per year. These regulations include provisions for facility registration, setting of state-wide GHG emissions allowances, initial allocation of GHG emissions, trading and banking of GHG emissions, and the provisions for the creation and use of GHG emission offsets.
Title 20, California Code of Regulations, section 2900 et seq.; CPUC Decision D0701039 in proceeding R0604009	The regulations prohibit utilities from entering into long-term contracts with any base load facility that does not meet a greenhouse gas emission standard of 0.5 metric tonnes carbon dioxide per megawatt-hour (0.5 MT CO_2/MWh), equivalent to 1,100 pounds carbon dioxide per megawatt-hour (1,100 lbs CO_2/MWh).
Local	
SJVAPCD Rule 2410	This rule incorporates by reference the current federal PSD rule including the GHG emissions permitting requirements.

Carbon Sequestration and Greenhouse Gas Emissions Table 2
OEHI CO_2 EOR Component
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	
40 Code of Federal Regulations (CFR) Part 98	This rule requires mandatory reporting of GHG emissions for facilities that emit more than 25,000 metric tons of CO_2 equivalent emissions per year. This requirement is triggered on this project. Subpart RR requires that reporting of geologic CO_2 sequestration, including reporting the amount received, injected, and emitted from surface activities.
40 CFR Parts 51, 52, 70 and 71	This rule "tailors" GHG emissions to PSD and Title V permitting applicability criteria. A new stationary source that emits more than 100,000 TPY of GHGs is considered to be a major stationary source subject to PSD requirements. This project would not trigger the 100,000 TPY PSD threshold.
40 CFR Part 146, Subpart H, §146.81 et seq.	Federal UIC regulations for injection wells intended for long term storage of carbon dioxide
State	
California Global Warming Solutions Act of 2006, AB 32 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)	This act requires the California Air Resource Board (ARB) to enact standards that will reduce GHG emission to 1990 levels by 2020.
California Code of Regulations, tit. 17, Subchapter 10, Article 2, sections 95100 et. seq.	These ARB regulations implement mandatory GHG emissions reporting as part of the California Global Warming Solutions Act of 2006 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)
California Code of Regulations, tit. 17, Subchapter 10, Article 5, sections 95800 et. seq.	These ARB regulations cap greenhouse gas emissions from specified California emission sources that emit more than 25,000 metric tons of CO_2 equivalent emissions per year. These regulations include provisions for facility registration, setting of state-wide GHG emissions allowance budgets, initial allocation of GHG emissions, trading and banking of GHG emissions, and the provisions for the creation and use of GHG emission offsets. Currently these regulations do not have methodologies for accounting for geologic sequestration projects; however, ARB is beginning work on these parts of the regulation.
California Code of Regulations, tit. 14, sections 1722-1724	Regulations for the construction and operation of Class II injection wells that would be used to inject the CO_2 for sequestration purposes.

CLIMATE CHANGE, GREENHOUSE GASES, AND THE DOE CLEAN COAL POWER INITIATIVE FINANCIAL ASSISTANCE – DOE

As described in more detail in the **Introduction** section of this PSA/DEIS, the DOE selected the proposed project for further, more detailed consideration for financial assistance. The project would serve the DOE's Clean Coal Power Initiative (CCPI) Round 3 objective to demonstrate advanced coal-based technologies that capture and sequester CO_2 emissions. DOE believes that accelerated commercial use of new or improved technologies will help sustain economic growth, yield environmental benefits, and produce a more stable and secure energy supply.

Demonstration and advancement of technologies that increase efficiency, facilitate carbon capture, beneficially use CO_2, and ultimately sequester CO_2 are important steps in developing strategies for controlling GHG emissions. The 2007 IPCC report states that there is "high agreement" that atmospheric concentrations can be stabilized by "deployment of a portfolio of technologies that are either currently available or expected to be commercialized in coming decades assuming that appropriate and effective incentives are in place for their development." The IPCC identifies carbon capture and storage (CCS) for coal-fired power plants as one of the "key mitigation technologies" for development before 2030 (IPCC 2007c). The IPCC notes that energy efficiency will also play a key role in stabilizing atmospheric concentrations of GHGs.

DOE believes that the objectives of the CCPI cost-shared effort between the U.S. Government and industry fulfill, in part, the recommendations of the IPCC. The DOE further believes that by providing financial assistance for this proposed project, the DOE would be providing appropriate incentives for developing technologies that can help reduce GHG emissions and climate change concerns. Therefore, successful demonstration of the proposed project, in combination with its broader-scale application of its technology, and other similar DOE-sponsored GHG-reducing initiatives in the region and across the U.S., would be expected to result in a significant long-term cumulative (beneficial) effect by reducing GHG emissions and addressing climate change concerns.

DOE does acknowledge that the oil produced by EOR (i.e., CO_2 floods) would ultimately lead to the emissions of CO_2 to the atmosphere when the oil-derived products are produced and consumed. However, DOE does not expect that this project would result in increased GHG emissions from consumption of oil-derived fuels domestically or globally. Domestic production of crude oil in 2011 was 5.7 million barrels per day (bpd). The estimated CO_2 capture rate for this project would be as high as 3.0 million tons per year (2.7 MMTA). Assuming a typical CO_2 EOR efficiency of 3.1 barrels of crude oil produced per metric ton of CO_2 sequestered, this project could result in an average crude oil production rate of approximately 23,000 bpd (0.023 million bpd) over the life of the project[8]. DOE believes that the resulting 0.40 percent increase in domestic supply of crude oil would not be enough to change the market price. With no price signal, the project would not affect the crude oil consumption rate, and therefore there would be no change in CO_2 emissions from the combustion of oil-derived fuels.

DOE predicts that the increased domestic crude oil production from this project would offset imports of crude oil as a source of supply. Imported crude oil is more expensive and would be the first source to be offset with an increase in domestic supply. This assertion is supported by crude oil supply data from the Energy Information

[8] Please note that OEHI has estimated oil production as approximately 4,500 to 22,500 bpd for the EOR component (HECA 2012dd).

Administration. During the economic downturn in 2007, demand for crude oil decreased. However, domestic supply remained level, and all of the reduction in supply came from imports. Based on the estimated crude oil production rate of 0.023 million barrels per day and using a five-year rolling average price for crude oil of $78.00 per barrel, which might underestimate future oil prices by 25 percent or more, the project would reduce the outflow of cash for imported crude oil by roughly $650 million per year and enhance the nation's energy security.

GHG NO ACTION ALTERNATIVE – DOE

If HECA is not built, it cannot be assumed that the additional emissions attributed to the project would be avoided. Other less efficient or more CO_2-emitting fossil fuel power plants might be constructed in its place, existing plants might produce more power thereby increasing their CO_2 emissions, or existing, less efficient and/or more CO_2-emitting fossil fuel power plants might remain online instead of being replaced.

Under the No-Action Alternative, DOE would not provide financial assistance to the applicant for the HECA Project. The applicant could still elect to construct and operate its project in the absence of financial assistance from DOE, but DOE believes this is unlikely. For the purposes of analysis in the PSA/DEIS, DOE assumes the project would not be constructed under the No-Action Alternative.

In the No-Action Alternative, demonstration of the project's integration of technologies for carbon capture, geologic storage of CO_2 through EOR, generation of electricity, and manufacture of urea would not occur. Consequently, commercialization of these integrated technologies may be delayed or not occur because utilities tend to use demonstrated technologies with predictable costs and risks. The No-Action Alternative would not contribute to DOE goals of accelerating advanced emission controls and demonstrating new coal technologies that capture and beneficially use CO_2.

The No-Action Alternative would not directly cause appreciable global warming that would lead to climate changes. However other sources of GHG's would continue to increase the atmosphere's concentration of GHG's, and, in combination with past and future emissions from all other sources, contribute incrementally to the global warming that produces the adverse effects on climate change. At present, there is no methodology that would allow DOE to estimate the specific impacts (if any) this increment of warming would produce in the vicinity of the plant or elsewhere.

Domestically produced oil, with or without EOR, reduces CO_2 emissions caused by the transportation of foreign oil into the United States. The average distance of "water carrier" transport of imported oil is estimated at 4,300 miles/barrel (bbl). The CO_2 equivalent emissions associated with this transport are estimated at approximately 12 pounds of CO_2 per barrel of foreign oil transported to refineries in the United States. Based on the estimated increased production of domestic oil resulting from the use of the project's CO_2 for EOR at the OEHI (4,500 to 22,500 bbl/day), HECA could result in a

CO_2 reduction of 10,000 to 49,000 tons/yr. This potential reduction in CO_2 would not be realized under the No-Action Alternative.[9]

Similarly, under the No-Action Alternative, there would be no production of urea or other nitrogenous compounds. HECA is estimated to generate 550,000 tons/yr of pelletized urea. Presently, all of the urea consumed in California's Central Valley is produced outside of California. Rail transport from the mid-west accounts for approximately 60 percent of the urea used in the Central Valley; at certain times of the year 20 percent is imported from Canada (via rail) and 20 percent is imported from China and Russia (via ocean transport and rail). Accordingly, the No-Action Alternative would require California's Central Valley to continue to import 100 percent of its urea, resulting in CO_2 from its transportation. Unlike the urea produced by HECA, it is likely that this imported urea is produced by facilities that do not capture and sequester their CO_2 emissions.

GHG EMISSIONS SOURCES DESCRIPTION– William Walters

The proposed project includes two components for purposes of this analysis: emissions from the HECA site (HECA component) and emissions resulting from the OEHI CO_2 EOR activities (OEHI CO_2 EOR component).This section includes short descriptions of each.

HECA

HECA would be an integrated gasification combined cycle (IGCC) project, which gasifies the fuel feedstocks, in this case nominally 25 percent petroleum coke (petcoke) and 75 percent sub bituminous coal, into a hydrogen rich fuel that is used in the combined cycle gas turbine to make electricity. The raw CO_2 emissions from this process are not substantially different from other types of coal fired power technologies; however, this technology allows separation of the fuel carbon, in the form of carbon dioxide, prior to the power production process. Once separated, the carbon dioxide can be sent for sequestration.

The HECA component's GHG emissions include both the direct onsite emissions from the fuel conversion and power production process, as well as emissions from an onsite fertilizer manufacturing complex and onsite ancillary and auxiliary equipment and from offsite feedstock, material, and personnel transportation. The onsite emissions sources include:

- Combustion Turbine Generator/Heat Recovery Steam Generator (CTG/HRSG)
- CO_2 Vent
- Auxiliary Boiler

[9] Variations in crude oil and relationships of supply and demand are not reflected in these numbers. Numbers calculated using DOE-NETL's UpStreamDashBoard_v2.0.3 (DOE 2013) available at http://www.netl.doe.gov/energy-analyses/refshelf/PubDetails.aspx?Action=View&PubId=439

- Thermal Oxidizer
- Gasification Flare
- Rectisol® Flare
- Sulfur Recovery Unit (SRU) Flare
- Emergency Engines
- CO_2 piping fugitive emissions
- Onsite dedicated mobile equipment
- SF_6 containing electrical equipment
- Coal Dryer
- Nitric Acid unit
- Urea Absorber Vents
- Ammonia Synthesis Plant Start-up Heater

The offsite emission sources include:

- Material Transportation (truck and train)
- Worker Transportation
- CO_2 transportation and sequestration process (described separately under the OEHI CO_2 EOR Component description)

Onsite GHG Emission Sources Description

The primary onsite GHG emissions, over 90 percent of the onsite total, are emitted from the combustion gas turbine/heat recovery steam generator (CTG/HRSG). Unlike a typical natural gas-fired power plant there are a number of onsite emission sources from the gasification process and fertilizer manufacturing complex, and there is a much larger consumption of onsite power which reduces the net power transmitted from the site when operating on hydrogen rich fuel. A description of the onsite emission sources follows with the expected annual emissions rates shown in **Carbon Sequestration and Greenhouse Gas Emissions Table 4** that is provided in the Electricity and Greenhouse Gas Emissions section. There are also the indirect GHG emissions and climate change factors of the reduction of CO_2 uptake through the change in land use, in this case removing land from active farming, and the change in land albedo. Staff has reviewed these factors for other much larger acreage renewable energy projects and has found that these indirect impacts are insignificant in comparison to a power plant's direct GHG emissions.

Large GHG Emissions Sources (>10,000 MT/year)

CTG/HRSG

The combustion turbine generator/heat recovery steam generator provides most of the electrical energy derived by this project. The CTG/HRSG proposed for this project is a Mitsubishi Heavy Industries 501GAC® (G-Class) model gas turbine operating in combined cycle mode with duct burners. The main gas turbine burners and duct burners would both be designed to operate on the hydrogen rich fuel from the gasification system or natural gas. Carbon sequestration would only occur when the gasifier is making hydrogen rich fuel. Sequestering carbon dioxide from natural gas combustion is not yet a technically mature technology at the scale of this project and would not be cost effective for this project given the fact that natural gas use would be very limited. Additionally, this project is a demonstration project for low carbon energy production from coal, so changing the project's primary fuel to natural gas would not fulfill the objectives of the project. The GHG emission performance when operating on natural gas is roughly the same as that for recently approved natural gas-fired combined-cycle projects. The primary GHG emissions from the CTG/HRSG would be CO_2 from the hydrogen rich fuel[10] and natural gas combustion, with small amounts of nitrous oxide and methane (natural gas combustion only) in the exhaust. The CTG/HRSG is, by a large margin, the largest HECA annual GHG emission source.

CO_2 Vent

When there are any upsets in the CO_2 transmission system or when the OEHI CO_2 EOR component cannot receive CO_2 due to upsets or other operating conditions, the CO_2 stream cannot be sequestered and would be vented onsite. The maximum annual CO_2 venting has been estimated to be 504 hours, which should only happen during early operations. CO_2 venting for mature operations is estimated to drop to no more than 120 hours per year. When operating the CO_2 vent has the second highest instantaneous GHG emission rate of any HECA emission source.

Auxiliary Boiler

The auxiliary boiler would be used to provide steam to facilitate CTG startup and other miscellaneous uses when Gasification Block or HRSG steam is not available. The auxiliary boiler would be limited to 2,190 hours per year of operation. The primary GHG emission from the auxiliary boiler is CO_2 from natural gas combustion, with small amounts of methane and nitrous oxide in the exhaust.

Gasification Flare

The gasification flare would be used to safely dispose of gasifier startup gases, syngas (also called unshifted and shifted gases[11]), and hydrogen-rich fuel generated during

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[10] Hydrogen rich fuel contains carbon dioxide created in the gasification process that is not able to be separated and sequestered.

[11] Shifted gas sent to the flare would contain large amounts of hydrogen and carbon dioxide but would still contain sulfur, as H_2S, and other impurities, such as low levels of mercury, not yet removed in the

short-term combustion turbine outages and other unplanned power plant upsets or equipment failures[12]. Reduced pressure sour gas would be scrubbed to remove sulfur and both high and low pressure gases would be vented through knockout drums to remove water and other entrained liquids. The primary GHG emissions from the gasification flare is the CO_2 emitted from the flare's combustion of the syngas, with smaller amounts of methane and nitrous oxide in the syngas flare exhaust, and small amounts of CO_2, methane, and nitrous oxide from the pilot gas combustion. The gasification flare, when operating under turbine outage or upset conditions and under full syngas production, has the highest instantaneous GHG emission rate of any HECA emission source. However, gasification flare operation is expected to occur only approximately 28 hours per year during startup/shutdown events, so it is expected that annual emissions would be well below those of the gas turbine/HRSG.

Coal Dryer

The coal dryer would be used to dry the feedstock. Its heat source is the hot turbine exhaust gas from CTG/HRSG. Exhaust gases from the CTG/HRSG are used to dry the coal before it is fed to the gasifier. These exhaust gases are collected from the HRSG after emissions control but before final heat recovery to provide adequate heat for the coal drying. The total annual operation of the coal dryer is 8,110 hours. The coal dryer uses approximately 14 percent of the HRSG off-gas flow and therefore approximately 14 percent of the total GHG emissions from the CTG/HRSG operations. For the purposes of the GHG emissions tables the CTG/HRSG and Coal Dryer GHG emissions are combined.

Moderate GHG Emissions Sources (>1,000 and <10,000 MT/year)

Thermal Oxidizer

The SRU tail gas thermal oxidizer would be operated to oxidize hydrogen sulfide (H_2S) and other vent gas components that are generated during startup, shutdown, and other miscellaneous gasification unit streams (tank and equipment vents) during normal operation to prevent nuisance odors during operation. The primary GHG emissions from the thermal oxidizer is CO_2 from the pilot gas and vent gas combustion, with small amounts of methane and nitrous oxide in the exhaust.

Rectisol® Flare

The Rectisol® flare would be used as an emergency flare to safely dispose of low temperature gas streams from the acid gas removal (AGR) unit and its associated refrigeration unit during startup, shutdown, and unplanned upsets or emergency events. These gases, which are first vented through a knockout drum to remove any entrained

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process. Unshifted gas sent to the flare would contain large amounts of carbon monoxide, carbon dioxide and hydrogen and would also contain sulfur compounds, as carbonyl sulfide (COS), and the other impurities contained in the shifted gas.

[12] The process is continuous without any significant syngas or fuel storage capacity so any upsets require the gases to be vented to a flare while the source of the upset is corrected or the gasification system is shutdown.

liquids prior to introduction to the flare header, are below the freezing point of water and require segregation from the other flared gases. The primary GHG emissions from the Rectisol® flare would be the CO_2 from the pilot gas and vented gas combustion, with small amounts of methane and nitrous oxide in the exhaust.

Nitric Acid Unit

Nitric acid production occurs through a three-step process consisting of ammonia oxidation, nitric oxide (NO) oxidation, and absorption. The total annual operation of the nitric acid unit would be 8,053 hours. The primary GHG emissions from the nitric acid unit would be the N_2O from the absorber column tail gas which would be cleaned before being discharged by catalytic decomposition and reduction of both N_2O and nitrogen oxides (NOx).

Small GHG Emissions Sources (<1,000 MT CO2E/year)

SRU Flare

The SRU flare would be operated to safely dispose of acid-gas streams containing sulfur from the AGR unit, gasification unit, and sour water stripper unit during startup or during emergency or upset events. The acid gas is first vented through an emergency caustic scrubber and knockout drum to remove sulfur compounds and entrained liquids and then vented to the flare for oxidation of the remaining acid gas. The primary GHG emissions from the SRU flare would be the CO_2 that is entrained in the acid-gas streams with additional CO_2 from the pilot gas and vented gas combustion and small amounts of methane and nitrous oxide in the exhaust.

Emergency Engines

The project is proposing two diesel-fired emergency generators (2,922 horsepower [hp] each) and one diesel-fired emergency fire pump (565 hp) that would combust diesel fuel during routine “readiness testing”. The primary GHG emissions would be CO_2 with smaller amounts of methane and nitrous oxide in the exhaust.

CO_2 Piping Fugitive Emissions

CO_2 would be emitted onsite from piping components (valves, flanges, compressor seals, etc.) within the gasification and CO_2 separation systems. For the purposes of onsite emissions, the fugitive emissions are assumed to occur from piping components until the CO_2 custody transfer point located near the HECA fence line, at which point additional CO_2 fugitive emissions are considered offsite emissions and thus under the control of Occidental Petroleum. At this point, responsibility for all of the OEHI CO_2 EOR component’s CO_2 emissions that are directly attributable to the CO_2 would be transferred from HECA to OEHI. However, GHG emissions attributable to the CO_2 sequestration are included in the overall CO_2 emissions estimate for the project. The CO_2 fugitive emissions are calculated in the same general manner as emissions of volatile organic compounds (VOC) from piping components within refineries.

Onsite Dedicated Mobile Equipment

This includes trucks, forklifts, and other on-road and off-road equipment that primarily or solely operates onsite. GHG emissions from this emission source are from the combustion of diesel, gasoline, or propane fuels.

SF_6 Containing Electrical Equipment

An electrical switchyard would be constructed onsite that would include eight new circuit breakers containing SF_6 as an insulator. A total of six 230 kilovolt (kV) circuit breakers containing 240 pounds (lbs) of SF_6 each and two 18 kV circuit breakers containing 73 lbs of SF_6 each have been proposed for the project. The emissions of SF_6 occur from equipment leakage, which have been conservatively estimated by the applicant to be one half of one percent per year.

Urea Absorber Vents

The low-pressure (LP) and high-pressure (HP) absorbers reduce the ammonia content of the off-gases from the urea synthesis process in the vents. The primary GHG emissions from the urea absorber vents would be the CO_2 from the off-gases.

Ammonia Synthesis Unit Start-Up Heater

The 55-Million British Thermal Units/hour (MMBtu/hr) natural-gas-fired start-up heater would be operated to heat the catalyst bed, used for ammonia synthesis reaction, during initial plant commissioning or during a start-up after a long period of plant shut-down. The annual heat input for this heater is not expected to exceed 7,700 MMBtu higher heating value, which is equivalent to approximately 140 hours of operation at full capacity. The primary GHG emissions would be the CO_2 from the natural gas combustion, with small amounts of methane and nitrous oxide in the exhaust.

Undetermined GHG Emissions Source

Limestone Fluxant

The applicant has revised the project description to include the use of a limestone fluxant in the gasifier feedstock. The maximum annual limestone fluxant use would be 59,000 tons per year. Limestone is composed of calcium carbonate ($CaCO_3$) that would breakdown and release carbon dioxide in the gasifier, with a maximum annual CO_2 emissions rate of approximately 23,550 metric tonnes per year (26,000 short tons/year). The applicant has not indicated how this additional generation of CO_2 would change the overall HECA CO_2 emissions/export balance; however, the total quantity of CO_2 from the fluxant is a small fraction of the maximum total CO_2 generated annually from the gasifier, which would be over 3 million tonnes. The emissions tables presented in this section do not include the potential CO_2 emissions from the fluxant shipping and use. Staff will provide updated emissions data that includes the fluxant shipping use in the FSA/FEIS.

Offsite GHG Emission Sources Description

Offsite emission sources include material delivery and employee transportation emissions and the emissions from the OEHI CO_2 EOR component's CO_2 sequestration process, where the latter is described separately below.

Material and Product Transport

HECA is considering two alternative methods for transporting materials and products to the project site:

- **Alternative 1, Rail Transportation.** An approximately 5-mile-long new industrial railroad spur that would connect the project site to the existing San Joaquin Valley Railroad Buttonwillow railroad line, north of the project site. This railroad spur would be used to transport coal to the site and fertilizer plant products to the market. Truck travel would still be used for petcoke delivery and other miscellaneous deliveries and hauling a portion of the secondary products (sulfur, ash) to market.
- **Alternative 2, Truck Transportation.** An approximately 27-mile-long truck transport route via existing roads from an existing coal transloading facility northeast of the project site. This alternative would be used to transport coal to the site. This alternative assumes petcoke and all fertilizer plant products and secondary products would be trucked to the site or to the market.

This includes delivery of the fuel feedstock by truck and train, other material deliveries and secondary product export trips, including fertilizer, ash, and sulfur. Staff has included a separate accounting of this emission source that was prepared by the applicant. However, fuel transportation emissions, including methane losses from pipeline transport, have not been included in past Energy Commission licensing case project GHG analyses; there currently is no regulatory requirement to control, offset, or inventory such emissions from stationary source projects such as HECA. Additionally, the petcoke and the fertilizer products might otherwise be shipped longer distances than they would with HECA. In the case of petcoke, it would otherwise be shipped overseas for use; and in the case of the fertilizer products, they might otherwise be shipped from outside of California for use in California. No analysis has been completed, or credit taken, for these potential net reductions in shipping emissions.

Employee Transportation

Employees would commute from communities surrounding HECA. The primary GHG emissions from employee vehicles would be CO_2 from their fuel combustion, with smaller amounts of methane and nitrous oxide. It is assumed that these GHG emissions, a minor source in the context of HECA, would be reduced over time as vehicle emissions are reduced through greater fuel efficiency or fuel substitution, including electrification.

OEHI CO_2 EOR COMPONENT

Occidental of Elk Hills, Inc. (OEHI) is proposing to extend the life of the EOR operations by using CO_2 from the proposed HECA project to facilitate oil production from its Elk

Hills Unit operations. The CO_2 would be compressed and delivered via pipeline to the OEHI's EOR Processing Facility. The process involves re-compressing and injecting the CO_2 to enable trapped oil to flow more readily into the reservoir, thereby improving recovery. Occidental Petroleum has stated that ultimately essentially all of the injected CO_2 is expected to become trapped in the formation and sequestered.

The EOR process would inject alternating slugs of CO_2 and water into a number of injection wells in what is known as the water alternating gas (WAG) injection process. The supercritical CO_2 that is used in this tertiary oil recovery process increases the miscibility and lowers the viscosity of the oil in the formation and the water sweep and then helps move the oil through the formation from the injection wells to the production wells. Occidental Petroleum notes that the industry standard CO_2 utilization efficiency ranges from 6 million standard cubic feet per barrel of produced petroleum oil (mmscf/bbl) to 30 mmscf/bbl. Assuming that the OEHI CO_2 EOR component falls into this range, Occidental Petroleum has estimated that they would produce an incremental 4,500 to 22,500 bbl/day of oil over the life of the project (HECA 2012dd).

There would also be the recovery of associated natural gas and natural gas liquids that would be sent offsite for sale by pipeline. In terms of their carbon and energy value they would be recovered in rates that would be much lower than the oil recovered. Therefore, these products are not the focus of the EOR component and their recovery rate has not been estimated by OEHI.

The OEHI CO_2 EOR component would include facilities to recapture, separate, and re-inject the CO_2 that accompanies the produced oil from the EOR process. Additionally, the water that accompanies the produced oil would also be recovered for reinjection. CO_2 would be injected continuously throughout the injection well field; any upsets that would require a CO_2 delivery shutdown would be handled at the HECA site (i.e. CO_2 venting), so that there would be no need to store any of the CO_2 received from HECA or recovered during the EOR process.

Occidental Petroleum has estimated that the maximum recycle rate of CO_2 that would occur prior to moving to a new injection and production well grid area would be approximately 550 mmscfd. Therefore, the maximum CO_2 injection rate would be 685 mmscfd, or approximately 4.7 times the amount of 135 mmscfd of CO2 that is received from HECA (OXY 2013c). Occidental Petroleum has not determined an average injection rate to establish expected long-term average emissions and noted that this analysis should use the maximum injection rate as the basis to determine the average annual emissions for the project (OXY 2013e).

The OEHI CO_2 EOR component's GHG emissions include the direct onsite emissions from EOR processing facility processes and the indirect onsite emissions from power consumption, as well as emissions from onsite ancillary and auxiliary equipment and from material and personnel transportation. The onsite emissions sources include the following sources:

- EOR Component Power Consumption (indirect)
- CO_2 Injection Heater
- Regeneration Gas Heater
- Triethlylene Glycol (TEG) Reboiler
- Amine Unit
- Central Tank Battery (CTB)
- Reinjection Compression Facility (RCF)
- Fire Pump Engines
- Piping Fugitives

The offsite emission sources include:

- Material Transportation
- Worker Transportation

Onsite GHG Emission Sources Description

Over 75 percent of the onsite GHG emission total is indirectly emitted emissions that account for the EOR component's power consumption. A description of the onsite emission sources follows with expected annual emissions rates shown provided later in this section in **Carbon Sequestration and Greenhouse Gas Emissions Table 7**.

Large GHG Emissions Sources (>10,000 MT/year)

EOR Power Consumption

The EOR component would require a total of approximately 940,000 MWh/yr, which is approximately 34 percent of HECA's annual generation total. The indirect GHG emissions from the EOR power consumption is by a large margin, at over 80 percent of the total EOR component's CO2E emissions, the largest OEHI CO_2 EOR component GHG emission source.

CO_2 Injection Heater

The CO_2 injection heater would be used to maintain desired operating temperatures. The primary GHG emissions from the CO_2 injection heater would be the CO_2 from the natural gas combustion, with small amounts of methane and nitrous oxide in the exhaust.

Moderate GHG Emissions Sources (>1,000 and <10,000 MT/year)

Regeneration Gas Heater

The regeneration gas heater would be used to heat up the regeneration gas from the molecular sieve bed where the gas is dehydrated to prevent ice or hydrate formation in the cold sections of the fractionation system. The primary GHG emissions from the CO_2

injection heater would be the CO_2 from the natural gas combustion, with small amounts of methane and nitrous oxide in the exhaust.

TEG Reboiler

The Triethylene Glycol (TEG) reboiler would be used to dehydrate the TEG to the CO_2 water content specification. This dehydration step would allow for the use of standard carbon steel material throughout the reinjection compression facility. The primary GHG emissions from the CO_2 injection heater would be the CO_2 from the natural gas combustion, with small amounts of methane and nitrous oxide in the exhaust.

Flares

OEHI proposes to use flares for the Central Tank Battery (CTB) and the Reinjection Compression Facility (RCF). These intermittent sources would operate only a few hours per year and would primarily have emissions of CO_2 from combustion of their pilot gas and their occasional flare use, with small amounts of methane and nitrous oxide in the exhaust.

Small GHG Emissions Sources (<1,000 MT CO2E/year)

CTB

The CTB would be used as the primary oil/water separation system for the CO_2 EOR process and would be collocated with the RCF and CO_2 Recovery Plant (CRP). It would consist of an inlet header system, gas separators, gas flume, and vortex tanks for oil/water separation. The primary GHG emissions from the CTB would be a small amount CO_2 and methane from the vortex tank breathing and working loss for the small amount of each that remains in the liquids after the gases are separated, and the piping component fugitives.

Amine Unit

The amine unit would remove the remaining CO_2 and sulfur compounds and then reduce the nitrogen content in the recovered hydrocarbon gases before they are sent to sales. The primary GHG emissions from the amine unit would be from the Nitrogen Removal Unit (NRU) heater and the CO_2 that is entrained in the acid-gas streams lost as fugitive emissions.

Fire Pump Engines

The project is proposing two fire pump engines (175 hp each). The primary GHG emissions from the fire pump engines would be the CO_2 from the diesel fuel combustion during routine readiness testing.

Piping Fugitives

Fugitive emissions of CO_2 may occur in some areas of the facility due to leaks in the piping and components. Piping fugitives are associated with all areas of the well fields and EOR processing facility, but do not include upsets, such as well blow-outs.

Offsite GHG Emission Sources Description

Offsite emission sources include material delivery and employee transportation emissions.

Material and Product Transport

This includes material deliveries and associated oil production secondary product (natural gas liquids and sulfur) export trips. The primary GHG emissions from employee vehicles would be CO_2 from their fuel combustion, with smaller amounts of methane and nitrous oxide. It is assumed that these GHG emissions, a minor source in the context of the OEHI CO_2 EOR component, would be reduced over time as vehicle emissions are reduced through greater fuel efficiency.

Employee Transportation

Employees would commute from communities surrounding the OEHI CO_2 EOR component. The primary GHG emissions from employee vehicles would be CO_2 from their fuel combustion, with smaller amounts of methane and nitrous oxide. It is assumed that these GHG emissions, a minor source in the context of the OEHI CO_2 EOR component, would be reduced over time as vehicle emissions are reduced through greater fuel efficiency or fuel substitution, including electrification.

ELECTRICITY AND GREENHOUSE GAS EMISSIONS

ELECTRICITY PROJECT GREENHOUSE GAS EMISSIONS

The system to deliver adequate and reliable electricity supply is complex and variable. But it operates as an integrated whole to meet demand, such that the dispatch of a new source of generation generally curtails or displaces one or more less efficient or less competitive existing sources. Within the system, generation resources provide electricity, or energy, generating capacity, and ancillary services to stabilize the system and facilitate electricity delivery, or movement, over the grid. *Capacity* is the instantaneous output of a resource, in megawatts. *Energy* is the capacity output over a unit of time, for example an hour or year, generally reported as megawatt-hours (MWh) or gigawatt-hours (GWh). Ancillary services[13] include regulation, spinning reserve, non-spinning reserve, voltage support, and black start capability. Individual generation resources can be built and operated to provide only one specific service. Alternatively, a resource may be able to provide one or all of these services, depending on its design and constantly changing system needs and operations.

California is actively pursuing policies to reduce GHG emissions that include adding non-GHG emitting renewable generation resources to the system mix. The generation of electricity using fossil fuels produces air emissions known as greenhouse gases in addition to the criteria air pollutants that have been traditionally regulated under the

[13] See page CEC 2009c, page 95.

federal and state Clean Air Acts. Greenhouse gas emissions contribute to the warming of the earth's atmosphere, leading to climate change.

This analysis provides staff's conclusions concerning greenhouse gas emissions for this siting case. Future power plant siting and amendment cases are likely to be reviewed with the benefit of new information and policy direction from the Energy Commission. This analysis recognizes that the "prudent use" of fossil fuels for electricity generation will serve to optimize the system (for providing reliability), but, without further analysis and policy direction by the Commission to refine this general understanding, this analysis leaves the implications for optimizing the system to future cases (CEC 2009b).

PROJECT CONSTRUCTION

Construction of industrial facilities such as power plants requires coordination of numerous equipment and personnel. The concentrated on-site activities result in short-term, unavoidable increases in vehicle and equipment emissions that include greenhouse gases. The construction would last 42 months. The greenhouse gas emissions estimate, presented below in **Carbon Sequestration and Greenhouse Gas Emissions Table 3,** were converted by staff into MT CO2E and totaled.

Carbon Sequestration and Greenhouse Gas Emissions Table 3
Estimated HECA Construction Greenhouse Gas Emissions

Construction Element	CO_2-Equivalent (MT CO2E) [a,b]
Project Construction Emissions	
On-Site Combustion Emissions	
Construction Equipment – On-road	5,244.7
Construction Equipment – Off-road	8,385.2
Worker Vehicles	249.9
Delivery Trucks	353.8
Linear Combustion Engines	2,450.9
Subtotal of On-Site and Linear Emissions	16,684.5
Off-Site On-Road Emissions	
Off-Site Combustion Emissions	
Worker Vehicles	14,536.2
Delivery Trucks	5,376.6
Subtotal of Off-Site On-Road Emissions	19,912.9
Total Emissions	36,597.4

Source: HECA 2013a, HECA 2013b
[a] One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms
[b] The vast majority of the CO2E emissions, over 99 percent, is CO_2 from these combustion sources.

PROJECT OPERATIONS

Alternative 1

GHG emissions associated with the operation of HECA are shown in **Carbon Sequestration and Greenhouse Gas Emissions Table 4**. Operation of the proposed HECA project would cause GHG emissions from a number of onsite and offsite sources including the CTG/HRSG, CO_2 vent, auxiliary boiler, thermal oxidizer, gasifier, fertilizer manufacturing units, onsite facility vehicle fleet trips (including from locomotives/switch engine), and employee trips.

Carbon Sequestration and Greenhouse Gas Emissions Table 4 shows the proposed project's expected annual GHG emissions, as permitted by emission source, during early and mature operation periods. All emissions are converted to CO2E and totaled. Electricity generation GHG emissions are generally dominated by CO_2 emissions from the carbon-based fuels; other sources of GHG are typically small and also are more likely to be easily controlled or reused/recycled. **Carbon Sequestration and Greenhouse Gas Emissions Table 4** shows the project's emissions without the CO_2 that is transported to the OEHI CO_2 EOR component for sequestration. The CO2E emissions attributable to the OEHI CO_2 EOR component and the combined HECA and OEHI CO_2 EOR totals are provided later in this document.

Carbon Sequestration and Greenhouse Gas Emissions Table 4
Estimated HECA Alternative 1 Operating GHG Emissions with Sequestration

Operating Assumptions	**Early Operations[a] (Maximum Permitted)**	**Mature Operations[a]**	**Expected Mature Syngas Operations[a]**
Natural Gas Operation, hours/yr	351	351	15
Hydrogen-Rich Fuel Operation, hours/yr	8,108	8,108	8,108
Intermittent CO_2 venting, hours/yr	504	120	0
Stationary Sources	**Annual CO2E (MT/yr)[b]**	**Annual CO2E (MT/yr)[b]**	**Annual CO2E (MT/yr)[b]**
CTG/HRSG Hydrogen-Rich Fuel and PSA Off-Gas	269,153	269,153	269,153
CTG/HRSG Natural Gas	44,772	44,772	1,913
CO_2 Vent	174,113	41,456	0
SF_6 circuit breakers	86	86	86
Flares	8,257	8,257	8,257
Thermal Oxidizer	5,946	5,946	5,946
Emergency generators and fire pump	181	181	181
Auxiliary Boiler	24,782	24,782	24,782
Ammonia synthesis plant start-up heater	409	409	409
Urea absorber vents	116	116	116
Nitric acid unit	12,659	12,659	12,659
Fugitives	83	83	83
Subtotal Stationary Sources	**540,557**	**407,900**	**323,585**
Mobile Sources	**Annual CO2E (MT/yr)[a]**	**Annual CO2E (MT/yr)[a]**	**Annual CO2E (MT/yr)[a]**
On-site trucks	413	413	413
On-site trains	291	291	291
Off-site workers commuting	824	824	824
Off-site trucks	10,866	10,866	10,866
Off-site trains	45,226	45,226	45,226
Subtotal Mobile Sources	**57,620**	**57,620**	**57,620**
Total HECA CO2E Emissions (MT/year)	**598,177**	**465,520**	**381,205**

Sources: HECA 2012e, HECA 2013a, HECA 2013b, and staff's interpretation of net generation.
[a] Early operations, which are assumed to occur during the first two years of operation, include maximum permitted amounts of natural gas use and CO_2 venting that could occur early in HECA facility operation and OEHI CO_2 EOR component operation when both are undergoing initial commissioning and operators are learning how to operate most efficiently alone and in concert. For the mature operations case, which is assumed to occur after the first two years of operation, the applicant assumes that there are fewer upsets requiring CO_2 venting due to optimization of operations that occurs over time. Finally, the applicant expects that mature operations could occur with very little natural gas firing, startup/shutdown only, and with no CO_2 venting. This expected mature syngas operations case represents the best case scenario for GHG emissions during mature operations. All permits would be based on the limits in the Early Operations case, which is the worst-case scenario that staff has used to determine LORS compliance; the other two cases were provided by the applicant for informational purposes for expected versus permitted emissions.
[b] One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms.

The proposed project as shown above in **Carbon Sequestration and Greenhouse Gas Emissions Table 4** is estimated to emit, directly from primary and secondary emission sources on an annual basis, as much as 600,000 MT CO2E/yr during the early operations period and that it could be reduced to approximately 380,000 MT CO2E/yr during mature syngas only operations.

The offsite material transportation GHG emission estimates provided by the applicant, including fuel stock transportation, are also provided in **Carbon Sequestration and Greenhouse Gas Emissions Table 4**. These mobile source emissions do not count towards SB 1368 EPS compliance. Additionally, no accounting for the offset of emissions from transportation that would occur in lieu of the project, such as alternate transportation of the petcoke to other users, is included in this emissions summary table.

Alternative 2

Alternative 2 changes the feedstock and product transportation assumptions for the project, the other emission sources at the project site are not affected. This alternative would not have a rail spur, so the feed materials and the products would be shipped to and from the site by truck, where the coal is shipped by train to Wasco and trucked from Wasco to the site. The distance for the shipping of the fertilizer products under this alternative is reduced as those products when shipped by truck are assumed to be shipped to regional distribution/transloading facilities within a 40 mile radius of the site, rather then shipped by train to more distant locations. **Carbon Sequestration and Greenhouse Gas Emissions Table 5** summarizes facility emissions under Alternative 2 and presents the total project emissions for this alternative. These mobile source emissions do not count towards SB 1368 EPS compliance. Additionally, no accounting for the offset of emissions from transportation that would occur in lieu of the project, such as alternate transportation of the petcoke to other users, is included in this emissions summary table. The GHG emissions from Alternative 2 are nearly identical to those from Alternative 1, with just a small increase in transportation emissions. The transportation emissions for Alternative 2 would have increased more if the same product delivery locations were assumed for these two alternatives.

Carbon Sequestration and Greenhouse Gas Emissions Table 5
Estimated HECA Alternative 2 Operating GHG Emissions with Sequestration

Operating Assumptions[b]	**Early Operations (Maximum Permitted)**	**Mature Operations**	**Expected Mature Syngas Operations**
Natural Gas Operation, hours/yr	351	351	15
Hydrogen-Rich Fuel Operation, hours/yr	8,108	8,108	8,108
Intermittent CO_2 venting, hours/yr	504	120	0
Stationary Sources	**Annual CO2E (MT/yr)**[a]	**Annual CO2E (MT/yr)**[a]	**Annual CO2E (MT/yr)**[a]
Subtotal Stationary Sources[c]	**540,557**	**407,900**	**323,585**
Mobile Sources	**Annual CO2E (MT/yr)**[a]	**Annual CO2E (MT/yr)**[a]	**Annual CO2E (MT/yr)**[a]
On-site trucks	867	867	867

Operating Assumptions[b]	Early Operations (Maximum Permitted)	Mature Operations	Expected Mature Syngas Operations
Off-site workers commuting	824	824	824
Off-site trucks	18,562	18,562	18,562
Off-site trains	37,464	37,464	37,464
Subtotal Mobile Sources	**57,717**	**57,717**	**57,717**
Total HECA CO2E Emissions (MT/year)	**598,274**	**465,617**	**381,302**

Sources: HECA 2012e, HECA 2013a, HECA 2013b, and staff determination of net generation.
[a] One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms.
[b] Operating assumptions are the same for Alternative 2, but are presented again for clarity.
[c] These values are the same as for Alternative 1, so only the subtotal is presented, please see **Carbon Sequestration and Greenhouse Gas Emissions Table 4** for the detailed stationary source emissions.

CLOSURE AND DECOMMISSIONING

Eventually the facility would close, either at the end of its useful life or due to some unexpected situation such as a change in market conditions or regulations. When the facility closes, all sources of air emissions would cease to operate and thus impacts associated with those greenhouse gas emissions would no longer occur. The only other expected, albeit temporary, GHG emissions would be equipment exhaust (off-road and on-road) from dismantling activities. These activities would be of a much shorter duration than construction of the proposed project, equipment used to dismantle the facility are assumed to have lower comparative GHG emissions due to technology advancement, and would be required to be controlled in a manner at least equivalent to that required during construction. It is assumed that the beneficial GHG impacts of this facility, displacement of higher GHG emitting fossil fuel fired generation, would be replaced by the construction of renewable energy or other low GHG generating technology facilities that would be necessary to comply with existing state regulations. Also, the recycling of the facility components (steel, concrete, etc.) could indirectly reduce GHG emissions from decommissioning activities. Therefore, these emissions would be substantially less than the HECA operation emissions and they are determined to be less than significant.

GREENHOUSE GAS/CLIMATE CHANGE IMPACTS AND MITIGATION

Staff assesses four kinds of impacts: construction, operation, closure and decommissioning, and cumulative effects. As the name implies, construction impacts result from the emissions occurring during the construction of the proposed project. The operation impacts result from the emissions of the proposed project during operation. Closure and decommissioning impacts result from emissions occurring due to the dismantling and restoration required at the end of the project's operational life. Cumulative impacts analysis assesses the impacts that result from the proposed project's incremental effect viewed over time. Staff is continuing to monitor development of AB 32 Scoping Plan implementation efforts and general trends and developments affecting GHG regulation in the construction and electricity sectors.

The impact of GHG emissions caused by the proposed facility must be considered in terms of how the power plant would affect emissions of the overall electricity system. The integrated electricity system depends on non-fossil and fossil-fueled generation resources to provide energy and satisfy local demands. The five separate roles that fossil fuel-fired power plants are most likely to fulfill in the future of a low-GHG system with increasing reliance on renewables include: 1) Intermittent generation support; 2) Local capacity requirements; 3) Grid operations support; 4) Extreme load and system emergencies support; and 5) General energy support (CEC 2009d, p. 93). HECA is analyzed below for its role in providing local capacity and base load generation and general energy support for expected generation retirements or replacements.

PROPOSED PROJECT

Construction Impacts and Mitigation

Staff concludes that the GHG emission increases from construction activities would not be significant for several reasons. First, the period of construction would be short-term, not ongoing during the life of the proposed project. Second, best practices control measures that staff recommends, such as limiting idling times and requiring, as appropriate, equipment that meets the latest emissions standards would further minimize greenhouse gas emissions since the use of newer equipment would increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of the ARB's low-carbon fuel regulations to reduce GHG from construction vehicles and equipment. Finally, the construction emissions are minimal in comparison with the GHG emission reductions that would occur from project operation. In fact, if the project construction emissions were distributed over the applicant projected minimum 25 year life of the proposed project those emissions would only increase the project life time annual facility GHG performance by approximately 0.0005 MT CO2E per MW, assuming that the project operates as a base load facility as assumed in **Carbon Sequestration and Greenhouse Gas Emissions Table 4**.

Operation Impacts and Mitigation

If sequestration is successful, the proposed HECA project, in the context of the Energy Commission's *Integrated Energy Policy Report*, promotes the state's efforts to move towards a low-GHG electricity system. As stated in the 2009 *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California* (CEC 2009d, p.20):

> When one resource is added to the system, all else being held equal, another resource will generate less power. If the new resource has a lower cost or fewer emissions than the existing resource mix, the aggregate system characteristics will change to reflect the cheaper power and lower GHG emissions rate.

Net GHG emissions for the integrated electric system will decline when new power plants are added that: 1) move renewable generation towards the 33 percent target; or 2) improve the overall efficiency, or GHG emission rate, of the electric system; or 3) serve load growth or capacity needs more efficiently, or with fewer GHG emissions. While HECA is not a natural gas-fired power plant, as designed it should provide base load energy at a lower GHG emission rate per megawatt than older natural gas-fired power plants and that are comparable with the emission rates of newer natural gas-fired power plants.

Additionally, HECA has several indirect GHG emissions benefits that are not directly related to electricity generation. These indirect benefits are:

- Petroleum extracted within California would be refined within California, which would reduce transportation emissions from imported oil. Additionally, all natural gas (i.e. methane) extracted would be collected and beneficially used, which is not always the case for imported oil.
- A portion of the CO_2 and hydrogen produced would be used to create fertilizer products that are a desired product within the agriculturally rich San Joaquin Valley. This could reduce the overall fertilizer transportation emissions to the San Joaquin Valley from more distant suppliers.
- The use of petcoke from California oil refineries would reduce their export overseas and reduce their transportation emissions. The exported petcoke is burned overseas and the associated GHG emissions are not controlled. These would be reduced approximately 90 percent by HECA, in the form of sequestered carbon dioxide.

While it can be concluded that the project has these indirect GHG emissions benefits, the exact amount of these indirect GHG emissions benefits cannot be reasonably quantified. Therefore, these indirect GHG emissions benefits have not been included in any of the GHG emissions quantifications provided in this section.

OEHI CO_2 EOR Component GHG Emissions

The OEHI CO_2 EOR component requires moving of the injection and production wells periodically, corresponding new or repurposed pipeline work, and new well drilling. Therefore, construction of this project is ongoing for the twenty year life of the project. The GHG emissions estimated for the OEHI CO_2 EOR component construction are summarized in **Carbon Sequestration and Greenhouse Gas Emissions Table 6**.

Carbon Sequestration and Greenhouse Gas Emissions Table 6
Estimated OEHI CO_2 EOR Component Construction Greenhouse Gas Emissions

	CO_2-Equivalent (MT CO2E) [a,b]
Total Construction Emissions (20-year period)	86,605
Annual Average Emissions	4,330

Source: HECA 2012s
[a] One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms
[b] The vast majority of the CO2E emissions, over 99 percent, is CO_2 from on-road and off-road combustion sources.

Operations GHG emissions for the OEHI CO_2 EOR component are shown In **Carbon Sequestration and Greenhouse Gas Emissions Table 7**. Operation of the proposed OEHI CO_2 EOR component would cause GHG emissions from a number of onsite and offsite sources including the EOR component power consumption (indirect), CO_2 Injection Heater, Regeneration Gas Heater, Triethlylene Glycol (TEG) Reboiler, Amine Unit, Central Tank Battery (CTB) Flare, Reinjection Compression Facility (RCF) Flare, Fire Pump Engines, Piping Fugitives, and materials and employee vehicle trips.

Carbon Sequestration and Greenhouse Gas Emissions Table 7
Estimated OEHI CO_2 EOR Operating GHG Emissions with Sequestration

OEHI CO_2 EOR Component Emission Sources	**Annual CO2E (MT)[a]**
CO_2 Injection Heaters	34,516
Regeneration Gas Heater	5,753
TEG Reboiler	2,876
Amine Unit	575
Fire Pump Engines	3
CTB – Flare	6,923
RCF – Flare	6,536
Fugitive GHG Emissions	115
Maintenance GHG	127
Pressure Relief GHG	2
Miscellaneous Small Tanks	4
EOR Component Power Consumption[b]	282,124
Workers Commuting	207
Well Maintenance Activities	215
Total EOR Component CO2E Emissions	**339,976**

Sources: HECA 2012e, OXY 2013c, OXY 2013e
[a] One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms
[b] The power consumption emission factor has been revised from the value of 524 lbs CO2E/MWh used by the applicant to the current recommended value of 661.2 lbs CO2E/MWh for the WECC California Area by The Climate Registry (TCR 2013)

The emissions estimates above are based on the maximum recycle rate correction provided by OEHI, and are also used as the project average emission rate per OEHI (OXY 2013a, OXY 2013b). Staff revised the power consumption emissions factor to the value currently recommended by The Climate Registry (TCR 2013) that staff feels is a more accurate value for new base load power consumption, which would be generated by a mix of newer generation resources including new natural gas-fired resources and renewable resources. The total cumulative project's emissions and the cumulative CO2E emission rate per net MWh are provided below in **Carbon Sequestration and Greenhouse Gas Emissions Table 8**.

Carbon Sequestration and Greenhouse Gas Emissions Table 8
Estimated HECA and EOR Component Emissions and Generation Efficiency

	Early Operations (Maximum Permitted)	Mature Operations	Expected Mature Syngas Operations
	Annual CO2E (MT)[a]	Annual CO2E (MT)[a]	Annual CO2E (MT)[a]
Direct Annual HECA Component CO2E Emissions [b]	**598,274**	**465,617**	**381,302**
Direct Annual EOR Component CO2E Emissions [b]	**62,182**	**62,182**	**62,182**
Total Combined Annual	**660,456**	**527,799**	**443,484**
Net Annual Generation [c]	940,281	940,281	839,481
Generation Efficiency (MT CO2E/MWh)	**0.702**	**0.561**	**0.528**

Sources: HECA 2012e, HECA 2012s, HECA 2013a, HECA 2013b, OXY 2013c, OXY 2013e, and staff interpretation of net generation.
[a] One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms.
[b] Emissions include the amortized annual construction emissions based on a 20 year project life, but do not include the indirect CO_2 emissions from electricity use.
[c] This is the total net generation including all generation and all consumption for HECA and the EOR component, including the air separation unit. This estimate is a preliminary staff estimate and will likely change when staff obtains a complete HECA facility energy balance from the applicant.

This table indicates, considering the addition of the HECA mobile source emissions, the direct and indirect emissions from the OEHI CO_2 EOR component, and all of the power consumption necessary for HECA and the EOR component that the combined CO2E emissions will be lower than those of other types of coal-fired power plants, but would be higher than those of efficient natural gas fired combined cycle power plants. For comparison the Avenal Energy power plant was estimated to have an emissions rate of 0.384 MT CO2E/MWh. However, unlike Avenal Energy, HECA and the EOR component would be providing useful products other than electricity, namely 1 million tons per year of nitrogen-based fertilizers from HECA and approximately 12,000 barrels per day of oil[14] from the EOR component. Therefore, comparing the CO2E efficiency between HECA and natural-gas fired combined cycle power plants is an incomplete comparison. The actual CO2E emissions and net efficiency in terms of CO2E per net MWh will be a function of the actual operating profile for the HECA facility and determination of actual CO_2 emissions from the OEHI CO_2 EOR component, which could be somewhat higher or lower than the values shown above.

CUMULATIVE IMPACTS

Cumulative impacts are defined as "two or more individual effects which, when considered together, are considerable or . . . compound or increase other environmental impacts" (California Environmental Quality Act [CEQA] Guidelines § 15355). "A cumulative impact consists of an impact that is created as a result of a combination of the project evaluated in the EIR together with other projects causing related impacts" (CEQA Guidelines § 15130[a][1]). Such impacts may be relatively minor and

[14] The total heat equivalent of 12,000 barrels per day of oil is approximately 920 MW per hour, and after consideration of useful efficiency, assuming around 33 percent efficiency, would be over 300 MW of equivalent useful energy. Considering that useful energy in the total efficiency would drop the maximum combined HECA and EOR component permitted efficiency value from 0.702 CO2E/MWh to 0.185 CO2E/MWh.

incremental, yet still be significant because of the existing environmental background, particularly when one considers other closely related past, present, and reasonably foreseeable future projects.

This entire assessment is a cumulative impact assessment. The project alone would not be sufficient to change global climate, but would emit greenhouse gases and therefore has been analyzed as a potential cumulative impact in the context of existing GHG regulatory requirements and GHG energy policies.

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Compliance with LORS is addressed both for the HECA component as necessary for the Committee to make a decision on this project, and for the associated OEHI CO_2 EOR component.

HECA

HECA would be subject to ARB's mandatory reporting requirements and potentially other future requirements mandating compliance with AB 32 that are being developed by ARB. How the project would comply with these ARB requirements is speculative at this time, but compliance would be mandatory. The ARB's mandatory GHG emissions reporting requirements do not indicate whether the project, as defined, would comply with the potential GHG emissions reduction regulations being formulated under AB 32. The project may have to provide additional reports and GHG reductions, depending on the future regulations expected from ARB.

Reporting of GHG emissions would enable the project to demonstrate consistency with the policies described above and the regulations that ARB adopts and to provide the information to demonstrate compliance with any applicable EPS that could be enacted in the next few years. Since this power project would be permitted for more than a 60 percent annual capacity factor, and to be financially viable would have to obtain a long-term contract from an IOU or POU, the project would be subject to the requirements of SB 1368 and the current EPS. As described below, HECA's GHG emission performance would be well below the SB 1368 EPS as long as the carbon dioxide emissions sent to the oil field remain sequestered underground. Operational period testing would be conducted to demonstrate compliance with the GHG performance standards.

GHG LORS COMPLIANCE

<u>EPS Compliance</u>

California's EPS prohibits California utilities from acquiring ownership shares in or entering into long-term contracts for energy with base load facilities whose CO_2 emissions exceed 1,100 lbs per MWh (0.5 metric tonnes per MWh). The EPS further defines annual average carbon dioxide emissions and annual average electricity production (§ 2904 and § 2905). The following practical assumptions are taken from those sections of the regulations:

1) The CO_2 emissions within the HECA project site that are included in the total CO_2 emissions for EPS compliance include the following CO_2 emission sources:
    a. CTG/HRSG (all fuels)
    b. CO_2 Vent [per §2904(c)]
    c. Gasification Flare [per §2904(c)]
    d. Rectisol® Flare [per §2904(a)]
    e. SRU Flare [per §2904(a)]
    f. Auxiliary Boiler [per §2904(a), ancillary equipment]
    g. Thermal Oxidizer [per §2904(a)]
    h. Gasification Heater [per §2904(a)]
    i. Gasification and Gas Handling Units Fugitives (piping components) [per §2904(c)]
    j. Ammonia Synthesis Plant Start-Up Heater
    k. Urea Absorber Vents
    l. Fertilizer Plant Fugitives

    Emissions sources a. through i. are sources considered necessary for, not ancillary to, the operation of the gasification process and gas turbine/HRSG. CO_2 emissions associated with the fertilizer manufacture (j. through k.) are included in the emissions total, and the positive amount of electricity generated by the fertilizer manufacture is also included in total facility net generation. The combined effect of including both the CO_2 emissions and electricity generation from the fertilizer manufacture actually reduces the project-wide CO_2 emissions per MWh value.

2) The CO_2 emissions within the HECA project site that are not included in the total CO_2 emissions for EPS compliance include the following CO_2 emission sources:
    a. Emergency Engines [per §2904(a), ancillary equipment]
    b. Onsite/Offsite Mobile Equipment [per §2904(a), vehicles]
    c. The carbon remaining in the gasification solids.

    The carbon in the gasification solids is not considered to be a CO_2 emission source, as is generally required per §2904(a)[15], since the carbon in the gasification solids is bound into the structure of the solids and will not be emitted

[15] Regardless that the carbon is in a solid form part (a) notes “the calculation shall assume that all carbon in the fuels is converted to carbon dioxide. However, in this case the petcoke and coal are not directly used as fuels but rather as feedstock to make the fuel, so the provision in part (a) is not considered applicable to the carbon left in the gasification solids.

as a gas, and the gasification solids are planned to be used as a secondary product that will supplant the use of other raw materials.

3) The CO_2 emissions within the OEHI CO_2 EOR component that are included in the total CO_2 emissions for EPS compliance include the following CO_2 emission sources:

   a. HECA's CO_2 emissions that are not sequestered, which at this time is only considered to be the piping and other fugitive emissions from the EOR component, and CO_2 that is dissolved in the recovered oil or contained in the produced natural gas that is not recovered and recycled back for re-injection.

   b. CO_2 emission created at the OEHI CO_2 EOR component that is directly related to the CO_2 sequestration. Those sources include:

      i) CO_2 Injection Heater

      ii) Regeneration Gas Heater

      iii) Triethlylene Glycol (TEG) Reboiler

      iv) Amine Unit

      v) Central Tank Battery (CTB) flare

      vi) Reinjection Compression Facility (RCF) flare

   c. Indirect CO_2 emissions generated from the electricity consumed to sequester the CO_2.

   These three emissions sources are considered necessary to meet the intent of the EPS regulation [§2904(c)] to determine the net amount of CO_2 emissions sequestered.

4) The CO_2 emissions within the OEHI CO_2 EOR component site that are not included in the total CO_2 emissions for EPS compliance include the following CO_2 emission sources:

   a. Emergency Engines [per §2904(a), ancillary equipment]

   b. CO_2 emissions created in the downstream refining or use of the recovered petroleum products.

   c. Onsite/Offsite Mobile Equipment [per §2904(a), vehicles]

   The GHG emissions from the EOR component's produced oil use are not considered to be relevant in the discussion of the project's impacts. With or without this project necessary oil production to meet petroleum product demand will occur, at the Elk Hills site using other means, domestically, or overseas. It can also be argued that production closer to demand, similar to the greenhouse reduction concept of using local products, actually reduces overall GHG emissions.

5) The total net MWh for determination of EPS compliance includes the following assumptions:

   a. The total net MWh to the grid from the HECA project site minus the MWh needed for operation of the Air Separation Unit [per §2905(a)].

   b. The total net MWh used in the fertilizer production [per §2905(a)] and incremental generation from the fertilizer production.

These interpretations of §2904 and §2905 are based on the following overarching concepts:

1) The onsite fuel preparation process (i.e. gasification process and its various emission sources) is not an ancillary process. This realizes that the actual fuel is the coal and coke feed stocks that are gasified as the hydrogen rich fuel combusted in the gas turbine/HRSG would not exist without the coal and coke.

2) The fact that the geologic sequestration is being performed by a third party and that the air separation unit will be owned and operated by a third party does not mean that additional CO_2 emissions created by the sequestration process or the energy (MWh) used in the air separation process, which is integral to the operation of the gasifier, can be neglected[16].

3) The petroleum produced by the sequestration process will supplant petroleum production that would occur elsewhere that would have similar or higher emissions, given that the sequestration process CO_2 emissions have been considered as part of HECA's CO_2 emission performance. Therefore, the downstream GHG emissions would not create an incremental increase in CO_2 emissions from petroleum production.

Additionally, there are three main operating conditions:

1) The production of hydrogen rich fuel with separation and sequestration of CO_2.
2) The production of hydrogen rich fuel with separation but no sequestration of CO_2 (i.e. CO_2 vent operating).
3) The generation of electricity with natural gas when the gasification system is not operating.

The applicant has provided annual assumptions for each of these operating conditions to create worst case (early and mature operations) and best case (mature operations) annual operating scenarios.

[16] If HECA were proposing to sequester CO_2 emissions using onsite injection wells into a salt formation, then the onsite emissions and electrical consumption would certainly be considered in the final CO_2 emissions performance. Similarly, if the air separation unit were owned and operated by HECA directly then the parasitic load would be considered in the total net MW calculations. The positive intent of allowing CO_2 sequestration to meet the EPS is lost if third party sequestration CO_2 emissions and electrical consumption are not considered as part of the total emissions performance.

Using these assumptions, and the applicant's CO_2 emission estimates for the HECA facility and Occidental Petroleum's CO_2 emission estimates for the EOR component, staff has completed a summary of the SB 1368 CO_2 emission sources and Net MW in **Carbon Sequestration and Greenhouse Gas Emissions Table 9**, where the worst-case (early operations and mature operations) and best-case (mature operations) annual operating scenarios from **Carbon Sequestration and Greenhouse Gas Emissions Table 4** have been tabulated to identify the project's potential range for CO_2 emission performance.

Carbon Sequestration and Greenhouse Gas Emissions Table 9
HECA SB 1368 EPS Compliance – Preliminary Calculations

	Early Operations (Maximum Permitted)	**Mature Operations**	**Expected Mature Syngas Operations**
Net Electrical Energy Production	**Annual CO_2 (MT/yr)**	**Annual CO_2 (MT/yr)**	**Annual CO_2 (MT/yr)**
CTG/HRSG Hydrogen-Rich Fuel, PSA Off-Gas and Coal Dryer	256,900	256,900	256,900
CTG/HRSG natural gas	44,729	44,729	1,911
CO_2 vent	174,113	41,456	0
Flares	8,252	8,252	8,252
Thermal Oxidizer	5,940	5,940	5,940
Auxiliary Boiler	24,758	24,758	24,758
Ammonia synthesis plant start-up heater	409	409	409
Urea absorber vents	116	116	116
Fugitives	38	38	38
HECA Stationary Source CO_2 EPS Emissions	**515,255**	**382,598**	**298,324**
OEHI CO_2 Emissions (long-term average) [b]	338,676	338,676	338,676
Net HECA SB 1368 CO_2 Emissions	853,931	721,274	637,000
	Annual MWh	**Annual MWh**	**Annual MWh**
HECA Facility Net MWh per year [c]	2,740,400	2,740,400	2,639,600
Air Separation Unit Energy Use (MWh per year) [d]	859,448	859,448	859,448
Total Net HECA Facility Net MWh per year	1,880,952	1,880,952	1,780,152
GHG Emission Performance with Sequestration	**MT CO_2/MWh**	**MT CO_2/MWh**	**MT CO_2/MWh**
HECA Only Emission Performance	0.274	0.203	0.168
HECA and OEHI Emission Performance	**0.454**	**0.383**	**0.358**
Emission Performance Standard	**0.500**	**0.500**	**0.500**

Sources: HECA 2012e, HECA 2012s, HECA 2013a, HECA2013b, and staff interpretation of net generation.
[a] One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms.
[b] These emissions do not match those on **CARBON SEQUESTRATION AND GREENHOUSE GAS EMISSIONS Table 8** because they are CO_2, not CO2E, and they do not include the annualized OEHI construction emissions.
[c] These values are based on the applicants values of 325 MWh net on hydrogen rich fuel when not subtracting the manufacturing facility parasitic load and generation and 300 MWh net when operating on natural gas.
[d] These values are based on an average hourly consumption rate of 106 MW for the ASU over 8,108 hours of operation per year. It should be noted that part of the ASU's gas production is used for fertilizer production; however, staff does not have enough information to determine what proportion is reasonable and so is conservatively assuming the entire power consumption is related to the gasifier operation and part of the HECA net MW determination.

There is the potential that there are greater CO_2 losses due to lower than expected separation efficiencies at HECA or lower than intended sequestration efficiency from the OEHI CO_2 EOR component; however, the emissions estimates show some margin of safety[17], so compliance with the EPS is expected as long as HECA's CO_2 is separated and sequestered through the OEHI CO_2 EOR component as proposed and the ratio of gas turbine operating hours versus venting hours is not substantially higher than the cases shown above. However, if the gas turbine operation is substantially lower than 8,100 hours per year and the venting hours are as high as permitted maximum level of 504 hours per year then there is the potential that HECA's CO_2 emission performance could exceed the EPS. Based upon preliminary data, if the facility were to reduce electricity production by 110 MW and maximize ammonia production during off-peak hours (eight hours per night), HECA would emit 0.51 MT CO_2/MWh, just above the 0.5 MT CO_2/MWh required by the EPS.

Staff is recommending staff conditions **GHG-1** through **GHG-3** and **GHG-5** to ensure compliance with this regulation. Condition **GHG-1** would require the project owner to prepare and operate under a CO_2 Emissions Performance Compliance Plan (EPCP) that would detail the operating procedures that would be used to reduce project site CO_2 emissions to the extent feasible and maintain emissions below the EPS. Condition **GHG-2** would require the project owner to shutdown gasifier operations if OEHI stops accepting the CO_2 for sequestration or otherwise as necessary for compliance with the EPCP, SB 1368, or other regulatory requirements. Condition **GHG-3** would require that the applicant, and through a binding contract OEHI, prepare and operate in compliance with a CO_2 Emissions Sequestration Plan (CO_2 ESP) that details the design and operation requirements, monitoring requirements and recordkeeping requirements for ensuring CO_2 emissions sequestration. Condition **GHG-5** would require HECA to annually compute their actual emission performance. Currently these conditions are preliminary. Staff is continuing our evaluation of the detailed requirements that are needed for these conditions and will publish any needed final amendments to these conditions in the FSA/FEIS.

Applicant Position

The applicant does not agree with staff's interpretation of the emissions accounting under the EPS (URS 2013). In general the differences are that staff includes emissions sources that the applicant does not, including the emissions from the OEHI CO_2 EOR component, staff includes the air separation unit's power consumption in the HECA net energy production calculation, and staff includes the fertilizer manufacturing plant's generation in the net generation totals. Therefore, staff includes more emissions in the numerator and less megawatt hours of generation in the denominator of the EPS determination. A summary of the applicant's stated position, based on their

[17] This margin of safety would increase if and when staff can determine that a portion of the air separation unit's electricity consumption can be apportioned to the manufacturing complex, rather than the entire consumption being counted against HECA's net generation. For example, if one third of the power consumption from the ASU can be apportioned to the manufacturing plant then the CO_2 emissions performance value for the early operations case would be reduced from 0.454 MT CO_2/MWh to 0.394 MT CO_2/MWh. Likewise, the margin of safety could decrease if HECA is not able to meet their expected operating hours profile due to factors such as the competitive California electricity market's acceptance of the electricity produced by HECA.

interpretation of the Energy Commission Regulations, Chapter 11, Article 1, is as follows:

- The EPS emission calculations include only the annual GHG emissions from each fuel used in any component directly involved in electricity production or associated with the sequestration of CO_2.
- Emissions from electricity production come from the CTG/HRSG and coal dryer when burning syngas, PSA off-gas and natural gas, and SF_6 from the circuit breakers.
- Emissions associated with the CO_2 sequestration include the CO_2 vent and fugitives from CO_2 preparation for sequestration.
- The EPS emission calculations do not include emissions associated with the Gasification Block (flares, thermal oxidizer), Manufacturing Complex (ammonia synthesis plant start-up heater, urea absorbers, and nitric acid unit), auxiliary boiler, emergency generators, fire pump, and vehicles.
- CO_2 emissions associated with the recovery of oil have nothing to do with power production at HECA or the sequestration of the CO_2. HECA would provide CO_2 to OEHI that would be pressurized adequately that it could be injected directly into the ground for sequestration without further compression. But since OEHI's main purpose is to extract oil, they would further pressurize this CO_2 so that it can push out the oil. Thus all emissions associated with the OEHI component that were presented in the Supplemental Environmental Information (SEI) are associated with the recovery of oil, and should not be included in the emission inventory for determining EPS compliance.
- The net electricity production calculated for EPS compliance for hydrogen-rich fuel generation includes the net power exported plus the power used on-site in the Manufacturing Complex minus the steam generated from the ammonia production unit.

The three major differences in approach are that: 1) staff is considering the coal and petcoke feedstocks to be the fuel, while the applicant is considering the gasification product as the fuel; 2) staff considers the air separation unit as an integral part of the plant, regardless of ownership, which must be considered in the HECA net energy production calculation; and 3) staff considers the CO_2 sequestration process as proposed to be integral to the project, while the applicant considers a theoretical sequestration project that does not exist and that would not cause additional emissions.

A comparison of staff's calculation approach for EPS emissions and HECA facility net MWh accounting and the applicant's approach for the range of operations, early operations and best case mature operations, is shown in **Carbon Sequestration and Greenhouse Gas Emissions Figure 1** and numerical values are provided in **Carbon Sequestration and Greenhouse Gas Emissions Table 10**.

Carbon Sequestration and Greenhouse Gas Emissions Figure 1 graphically shows how different the interpretations of EPS calculation requirements are between staff and the applicant. The applicant believes that only a very small part of the overall project, centered around the gasifier and gas turbine, should be included in the EPS calculations. Staff's interpretation of the SB 1368 regulation suggests that most of the project, and certainly the carbon sequestration portion of the project, must be included in the emissions and net electricity generation calculations to determine whether the project would comply with the EPS. **Carbon Sequestration and Greenhouse Gas Emissions Table 10** below shows in numeric terms just how different the EPS calculation approaches are between staff and the applicant.

Carbon Sequestration and Greenhouse Gas Emissions Table 10
HECA EPS Compliance – Staff Versus Applicant Comparison

	Early Operations Staff Assumptions	Early Operations Applicant Assumptions	Mature Operations Staff Assumptions	Mature Operations Applicant Assumptions
Net Electrical Energy Production	**Annual CO_2 (MT/yr)**	**Annual CO_2 (MT/yr)**	**Annual CO_2 (MT/yr)**	**Annual CO_2 (MT/yr)**
CTG/HRSG Hydrogen-Rich Fuel, PSA Off-Gas and Coal Dryer	256,900	256,900	256,900	256,900
CTG/HRSG natural gas	44,729	44,729	1,911	1,911
CO_2 vent	174,113	174,113	0	0
Flares, thermal oxidizer, auxiliary boiler	38,950	0	38,950	0
Manufacturing Complex	525	0	525	0
Fugitives	38	38	38	38
HECA Stationary Source CO_2 EPS Emissions	**515,255**	**475,780**	**298,324**	**258,849**
OEHI CO_2 Emissions (long-term average)	338,676	0	338,676	0
Net HECA SB 1368 CO_2 Emissions	853,931	475,780	637,000	258,849
	Annual MWh	**Annual MWh**	**Annual MWh**	**Annual MWh**
HECA Facility Net MWh per year	1,880,952	2,699,860	1,780,152	2,599,060
GHG Emission Performance with Sequestration	**MT CO_2/MWh**	**MT CO_2/MWh**	**MT CO_2/MWh**	**MT CO_2/MWh**
HECA Only Emission Performance	0.274	**0.176**	0.168	**0.100**
HECA and OEHI Emission Performance [b]	**0.454**	**0.176**	**0.358**	**0.100**
Emission Performance Standard	**0.500**	**0.500**	**0.500**	**0.500**

Sources: HECA 2012e, HECA 2012s, HECA 2013a, HECA 2013b, OXY 2013c, OXY 2013e, and staff's interpretation of net generation.
[a] One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms.
[b] HECA and OEHI emission performance could be as high as 0.51 MT CO_2/MWh during early operations under some staff assumptions.

The table above includes corrections to several errors in the applicant's data provided in AFC Table 5.1-23, as follows:

1) Only CO_2 emissions, not CO2E emissions are provided for the combustion emissions sources;
2) The SF_6 emissions source included in AFC Table 5.1-23 was removed; and
3) The emissions were updated per data responses received.

The differences shown in this table are significant in terms of percentage where staff's approach provides CO_2 emission performance results that are over two and a half times higher for the early operations case and over three and half times higher for the mature operations case. However, both calculation methods support the same finding that the project's emissions would be below the EPS.

GHG Emissions Cap and Trade

HECA is forecast to emit far more than the 25,000 MT CO2E applicability threshold for the cap and trade regulation (see **Carbon Sequestration and Greenhouse Gas Emissions Table 4**). Therefore, the project owner would be required to obtain GHG emission allowances, or other emissions reductions or offsets, in sufficient amounts to cover the GHG emissions to the atmosphere occurring within the facility (CCR Title 17 §95850(b)). The facility would also be regulated as a CO_2 supplier and would have a compliance obligation based on the CO_2 supplied minus the emissions geologically sequestered through use of an ARB-approved carbon capture and geologic sequestration quantification methodology that ensures that the emissions reductions are real, permanent, quantifiable, verifiable, and enforceable[18]. ARB staff has been directed to initiate a public process to establish a quantification methodology for geologic sequestration but ARB does not currently have a defined schedule to complete this process.[19] However, no ARB-approved methodology currently exists and HECA would currently have a compliance obligation for the total CO_2 supplied until ARB implements their geologic sequestration regulations.

HECA would be required to obtain sufficient valid compliance instruments (a combination of emission allowances, offset credits, or sector based offset credits, although offsets are limited to no more than 8 percent of total compliance obligation) every three years (triennially) to cover its triennial emissions by November of the year following each triennial compliance period, and they would have to retire at least 30 percent of their GHG emissions reported from the previous calendar year each November following that calendar year. HECA would have to obtain necessary GHG allowances or offset credits to meet its total compliance obligation. HECA would be subject to this regulation immediately upon facility start-up.

PSD Permitting

HECA is subject to GHG PSD permitting, which is included in the SJVAPCD PDOC (SJVAPCD 2013). The PDOC has concluded that the project meets GHG emissions best available control technology (BACT) requirements and also contains conditions relevant to GHG emissions. These conditions are included with the rest of the PDOC conditions in the Air Quality section of this PSA/DEIS.

GHG Emission Inventory and Reporting

HECA, which as proposed would emit significantly more than 25,000 MT CO2E per year, would be subject to both federal and state GHG emission inventory preparation and reporting. Staff is proposing under Condition of Certification **GHG-4** that these

[18] While regulations exist for electric generating facilities and for CO_2 suppliers, the regulations for geologic carbon sequestration under the Cap and Trade program have not yet been completed.

[19] See page 15 of ARB resolution: http://www.arb.ca.gov/regact/2010/capandtrade10/res1042.pdf

inventories and reports be kept at the site, for a period of 5 years, for inspection by appropriate agencies.

AVENAL PRECEDENT DECISION

The Energy Commission established a precedent in the Final Commission Decision for the Avenal Energy Project. This decision requires the Energy Commission to determine that any new natural gas fired power plants certified by the Energy Commission are likely to: (a) not increase the overall system heat rate for natural gas plants; (b) not interfere with generation from existing renewable facilities nor interfere with the integration of new renewable generation; and, (c) taking into account these factors, reduce system-wide GHG emissions and support the goals and policies of AB 32 (CEC 2009c, page 111).

While the decision is intended to apply to new natural gas fired projects, HECA would be fueled with a blend of 75 percent coal and 25 percent petroleum coke. Both of these have a much higher carbon content than natural gas. As proposed, the project would also use a limited amount of natural gas, with more being used in the early years of operation and less used as the project matures and the operators learn how to optimize operations as described above. Based upon preliminary data and subject to revision, HECA is estimated to emit from 0.454 MT CO_2/MWh to 0.51 MT CO_2/MWh during early years of operation and as little as 0.358 MT CO_2/MWh thereafter. In comparison, today's new natural gas fired combined cycles emit about 0.364 to 0.386 MT CO_2/MWh.

The system mentioned above is the Western Electricity Coordinating Council (WECC), which includes the western United States, the Canadian provinces of British Columbia and Alberta, and the northern portion of Baja California, Mexico. Staff's estimate of the average heat rate for natural-gas fired generation in the WECC, based on the Energy Information Administration's (EIA) Form EIA-923 data, is 0.41 MT CO_2/MWh Thus, when HECA is new, it would operate with CO_2 emissions that are higher per megawatt-hour than the electricity production system's average natural gas fired power plants and may exceed the EPS of 0.5 MT CO_2/MWh. However, when HECA is mature it would operate with CO_2 emissions that are below the system average and slightly lower than today's new natural gas combined cycle facilities.

If HECA were a conventional natural gas-fired plant, its having a higher heat rate upon starting operations than the WECC average would not affect a detrimental effect on the latter as it would displace higher-emission resources. As it burns gasified coal, however, its initial impact on average system-wide GHG emissions may be negative; see **The Role of HECA in Energy Displacement** below.

OEHI CO_2 EOR COMPONENT

GHG Emissions Cap and Trade

The OEHI CO_2 EOR component is also forecast to emit more than the 25,000 MT CO2E applicability threshold for cap and trade regulation. (see **Carbon Sequestration and Greenhouse Gas Emissions Table 7**). Therefore, Occidental Petroleum would be required to obtain GHG emission allowances in sufficient amounts to cover the GHG emissions to the atmosphere occurring within the facility and its other covered emissions units (CCR Title 17 §95850(b)). Additionally, Occidental Petroleum would be responsible for following an ARB-approved carbon capture and geologic sequestration quantification methodology, if and when the ARB-approved methodology is prepared, that would ensure that the emissions reductions from the EOR component's carbon sequestration are real, permanent, quantifiable, verifiable, and enforceable.

PSD Permitting

The OEHI CO_2 EOR component would trigger GHG PSD permitting. This permit would be processed by the SJVAPCD with the other required air quality permits for that project. Occidental Petroleum is not expected to file the necessary permit applications for the EOR component until a decision has been made on HECA. Therefore, the EOR component's GHG PSD permit is expected to be finalized well after the Energy Commissions licensing process has been completed. Because the EOR component is not subject to the Energy Commission's jurisdiction, the District would complete an Authority to Construct, which would be subject to public notice and by rule would have a comment period of at least 30 days. Staff has not identified any issues with the EOR component that might affect the timely completion of a GHG PSD permit.

GHG Emission Inventory and Reporting

The OEHI CO_2 EOR component would emit significantly more than 25,000 MT CO2E per year and would be subject to both federal and state GHG emission inventory preparation and reporting. Staff is proposing under Condition of Certification **GHG-4** that these inventories and reports be obtained by the HECA project owners from Occidental Petroleum and kept at the HECA site, for a period of 5 years, for inspection by appropriate agencies.

Because leaks of injected CO_2 have the potential to contaminate underground sources of drinking water (USDW), the U.S. EPA, with mandate under the Clean Water Act, has issued regulations to control injection wells intended for long term storage of CO_2 in terms of construction, operation, monitoring, plugging, post-injection site care (PISC), and closure, as well as financial responsibility for any maintenance and correction action plans. The U.S. EPA regulations were codified under 40 CFR part 146 subpart H commencing with subsection 146.81. Compliance of the project owner with the regulations for injection wells as required by Condition of Certification **GHG-3**, with the exception that the project owner would not have to obtain the actual permit, would ensure that impacts from the injection of the carbon dioxide would have no significant impacts on USDWs.

DIRECT/INDIRECT OPERATION IMPACTS AND MITIGATION

GHG Emissions During Plant Operation

HECA would produce GHG emissions during operations through the combustion of hydrogen-rich fuel produced by coal and petcoke gasification, as well as limited amounts of natural gas, to generate electricity. Preliminary data supplied by the applicant and shown in **Reliability Table 1** of the Power Plant Reliability section indicate the facility would operate 50 weeks a year, require 192 hours (total), to start up twice a year, have a 91.3 percent equivalent availability factor and an 85 percent capacity factor. On a typical day it would operate at full electrical power production (originally stated as 405 MW gross output, more recently stated as 416 MW) for 16 hours and at a reduced electrical output for the remainder of the day, when it would be maximizing fertilizer production. HECA would emit approximately 0.454 to 0.51 MT CO_2/MWh during early years of operation and as little as 0.358 MT CO_2/MWh during thereafter. In comparison, today's new natural gas fired combined cycles emit about 0.364 to 0.386 MT CO_2/MWh.

Approximately 92 percent of the CO_2 generated during from the gasification process would be separated and approximately 80 to 85 percent of the separated CO_2 would be exported by pipeline to Occidental Petroleum for sequestration in the process of enhanced oil extraction. Power production is forecast to occur over 90 percent of the year, and the hourly net electricity generation rate added to the grid would be turned down 45 percent during off peak periods. HECA's fertilizer plant provides limited flexibility in the use of the hydrogen production from the gasifier allowing part of the plant's generation to be dispatchable.

Based upon this preliminary data, HECA, upon operational maturity, promotes the state's efforts to move towards a low-GHG electricity system in two primary ways:

- The energy produced by HECA would displace energy from higher GHG-emitting coal- and natural gas-fired generation resources, lowering the GHG emissions from electricity generation in the western United States, Canada and Mexico, the relevant geographic area for the discussion of GHG emissions from California's electricity generation.
- The dependable capacity provided by HECA may facilitate the retirement of resources that are adversely affected by the State Water Resources Control Board's (SWRCB) policy on once-through cooling (OTC).

California's Energy Action Plan Loading Order

In 2003, the three key energy agencies in California at the time – the California Energy Commission (Energy Commission), the California Power Authority, and the California Public Utilities Commission (CPUC) – came together in a spirit of unprecedented cooperation to adopt an "Energy Action Plan" (EAP) that listed joint goals for California's energy future and set forth a commitment to achieve these goals through specific actions. The EAP is a living document meant to change with time, experience, and need. In 2005 the CPUC and the CEC jointly prepared an Energy Action Plan II to identify further actions necessary to meet California's future energy needs (CEC 2005).

The EAP's overarching goal is for California's energy to be adequate, affordable, technologically advanced, and environmentally-sound. Energy must be reliable – provided when and where needed and with minimal environmental risks and impacts. Energy must be affordable to households, businesses and industry, and motorists – and in particular to disadvantaged customers who rely on California government to ensure that they can afford this fundamental commodity. EAP actions must be taken with clear recognition of cost considerations and trade-offs to ensure reasonably priced energy for all Californians.

The EAP accomplishes these goals in the electricity sector by calling for a "loading order" specifying the priority order for how to balance electricity supply and demand. The loading order identifies energy efficiency and demand response as the state's preferred means of meeting growing electrical energy needs. After cost-effective efficiency and demand response, it relies on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs or provide services needed to reliably operate the electricity system, the loading order supports clean and efficient fossil-fired generation.

The Role of HECA in Energy Displacement

As electricity demand is largely independent of the generation resources used to meet it, the construction and operation of a new power plant results in displacement of energy from another generation source in an amount equal to that provided by the new facility. This section discusses the energy sources that would likely be displace by the construction and operation of HECA.

HECA can be expected to displace energy from other fossil-fueled resources:

- California's Renewable Portfolio Standard (RPS) calls for an amount equal to 33 percent of their retail sales to be purchased by the state's load-serving entities from qualifying renewable energy facilities by 2020. Similar albeit less ambitious standards have been established in other states. The development of HECA would not affect the obligation of load-serving entities to procure this amount of renewable energy. Nor would HECA affect the output of those few renewable generators that do not sell energy to entities with RPS obligations, as these plants have very low variable costs of generation and are thus able to sell into spot and short-term energy markets at nearly $0. Accordingly, HECA would not be expected to displace renewable energy.

- Both large hydroelectric facilities and nuclear plants have very low variable costs of production as well. Moreover the latter are not designed to cycle up and down. Both of these resources would be unaffected by the development of HECA.

If HECA were a conventional natural-gas fired plant, it would be possible to say that it would displace less-efficient gas fired generation and might or might not displace coal-fired generation, depending upon the latter's variable cost of production. In any case, the development of HECA would represent an unambiguous reduction in system-wide GHG emissions.

The role of HECA in energy displacement is complicated by several factors. When (new) fossil generation alternatives are limited to those combusting natural gas, both the new facility and the facility potentially displaced use the same fuel unless the latter combusted coal, and thus had a unambiguously higher GHG emissions rate. Accordingly, it has been reasonably assumed that the natural gas-fired generation units dispatched first–those with the lowest variable operating cost per MWh–would be those that combusted natural gas most efficiently in the production of electricity and, thus, would be those with the lowest GHG emissions per unit of electricity. As a result, when new facilities produce electricity they would replace higher GHG-emitting facilities and reduce system-wide GHG emissions. In combusting gasified coal, however, the fuel cost per unit of electricity produced may be lower for HECA than for a natural gas fired combined cycle. As such, it may be dispatched first despite – in its early years of operation - having a higher GHG emissions rate.

Furthermore, unlike conventional natural gas-fired generation, HECA produces products other than electricity and ancillary services. Even if fuel costs per MWh are higher for HECA than for a natural gas-fired combined cycle, HECA might choose to produce electricity at a price below that at which new combined cycles are willing to operate as generation may produce revenue streams for HECA other than those resulting from the sale of electricity and ancillary services. If HECA receives sufficient revenue for fertilizer production or for its CO_2 used for enhanced oil recovery, etc., and generation is a necessary component of these production processes, HECA may have sufficient financial incentives to generate electricity at prices below those at which new natural gas-fired combined cycles would be dispatched. Again, this could result in HECA being dispatched before a natural gas-fired combined cycle which, during the early years of HECA's operation, would have a lower GHG emissions rate.

The Role of HECA in Capacity Displacement

HECA would provide up to 160 MW of new electrical capacity and associated electrical energy to the grid[20]. Electricity demand in California reaches its peak during mid- to late-afternoons on the hottest weekdays of the summer. Dependable capacity–the amount of capacity that can be counted upon to be available during the peak demand for electricity–is needed to reliably serve loads; the generation fleet, in conjunction with

[20] This value represents the power generation under average annual ambient conditions and includes the parasitic loads of the fertilizer plant and the air separation unit.

demand response programs, must provide a sufficient amount of dependable capacity to meet demand on the highest load day of the year.[21] Load-serving entities in the California (Independent System Operator) ISO control area, for example, are required by the California ISO to procure dependable capacity in amounts determined by their peak load forecast.

The dependable capacity provided by HECA could assist in replacing that lost due to the EPS and the SWRCB's OTC policy, both discussed more fully below. Given uncertainties regarding load growth, the contribution of renewable resources to capacity needs over the next ten years, the availability of the San Onofre Nuclear Generating Station, etc., the amount of new dispatchable capacity that will be needed to serve loads reliably is presently uncertain. It should be noted, however, that required new capacity needs may largely be limited to and satisfied by projects in specific locations (e.g., the Los Angeles Basin) to meet local capacity requirements or be required to have operating characteristics that HECA is lacking (cycling ability, fast ramp rate, ability to operate over a wide output range).

Replacement of High GHG-Emitting Generation

High GHG-emitting base load electricity generation resources, such as conventional coal facilities, are effectively prohibited from entering into new, long-term contracts for California electricity deliveries as a result of the EPS adopted in 2007 pursuant to SB 1368. Between now and 2020, 1,549 MW of coal-fired generation capacity will have to reduce GHG emissions or be replaced; these contracts are presented in **Carbon Sequestration and Greenhouse Gas Emissions Table 11**.

Carbon Sequestration and Greenhouse Gas Emissions Table 11
Expiring Long-term Contracts with Coal-fired Generation 2013 – 2020

Utility	Facility	Contract Expiration	MW
Department of Water Resources (DWR)	Reid Gardner	2013 [a]	213
San Diego Gas and Electric (SDG&E)	Boardman	2013	84
Southern California Edison (SCE) [b]	Four Corners	2016	720
Turlock Irrigation District (TID)	Boardman	2018	55
Los Angeles Department of Water and Power (LADWP)	Navajo	2019	477
		TOTAL	**1,549**

Source: Energy Commission staff based on Quarterly Fuel and Energy Report (QFER) filings.

Notes:

[a] Contract not subject to EPS, but the Department of Water Resources has stated its intention not to renew or extend.

[b] The sale of SCE's share of Four Corners to Arizona Public Service was approved by the CPUC and subsequently by Federal Energy Regulatory Commission (FERC) in November 2012.

[21] This is usually the hottest weekday in the summer, when residential and commercial cooling loads are at their highest.

Retirement of Generation Using Once-Through Cooling

The State Water Resources Control Board (SWRCB) policy on cooling water intake at coastal power plants has led to the retirement and replacement of several plants that use once through cooling (OTC). Numerous others are likely to retire on or prior to assigned compliance dates,[22] some of which will require replacement.[23] The units with compliance dates on or before the end of 2020 are presented in **Carbon Sequestration and Greenhouse Gas Emissions Table 12.**

Carbon Sequestration and Greenhouse Gas Emissions Table 12
OTC Units with SWRCB Compliance Dates on or before December 31, 2020[24]

Plant Name & Unit	Local Reliability Area	Capacity (MW)
Alamitos 1 – 6	LA Basin	2,010
El Segundo 3 & 4	LA Basin	670
Encina 1 – 5	San Diego	950
Huntington Beach 1 & 2	LA Basin	430
Mandalay 1 & 2	Ventura	436
Morro Bay 3 & 4	None	650
Moss Landing 6 & 7	None	1,510
Moss Landing 1 & 2	None	1,020
Ormond Beach 1 & 2	Ventura	1,516
Pittsburg 5 - 7	SF Bay	1,311
Redondo Beach 5 – 8	LA Basin	1,356
Total		**11,859**

Note: Pittsburg Unit 7 (682 MW) does not use once-through cooling but would be required to shut down if Units 5 and 6 retire.

CO_2 EOR AND SEQUESTRATION ANALYSIS – Tad Patzek and Abdel-Karim Abulaban

HECA would generate larger amounts of CO_2 per gross megawatt-hour than permitted by the EPS for base load power plants. To achieve compliance with the EPS, HECA proposes to store excess production permanently in the geologic formation at the Elk Hills Oil Field (EHOF) where oil was extracted for the past several decades. The idea is that if these formations had the capacity to hold the oil for millions of years under the tremendous pressures known to exist in oil-bearing formations, they should be a

[22] Most of the OTC units are aging facilities, for which extensive retrofits would be uneconomical. While compliance using operational and structural controls is allowed, the ability of units to comply in this manner and still operate in a fashion that yields a sufficient revenue stream is questionable.

[23] The California ISO, CPUC and the Energy Commission are studying amount of OTC capacity that will require replacement.

[24] **Carbon Sequestration And Greenhouse Gas Emissions Table 12** does not include OTC units that retired prior to January 1, 2012, resources with compliance dates through 2020 that have already been slated for replacement (e.g., LADWP units at Haynes and Scattergood), or units with post-2020 compliance dates (the remaining units at Haynes and Scattergood, LADWP's Harbor combined cycle, and the nuclear facilities at San Onofre [which Southern California Edison announced on June 7, 2013 that they would close rather than repair it] and Diablo Canyon).

suitable place to store the CO_2 gas. The EHOF site has been used for decades to extract oil by the federal government and Occidental Petroleum, leaving a huge amount of pore space empty and hence capable of storing the excess amounts of CO_2 produced by the HECA project. The site is characterized by the presence of a syncline and an anticline that form a dome-like cap that makes it an excellent candidate to store the CO_2 gas. The dome-like formation is also comprised of several alternating layers of sand and shale, which is a favorable sequence of layers for the purpose of storing the CO_2 gas and preventing leaks. In addition, the presence of the shale layers offers a relatively elastic medium that acts as an elastic seal that would be useful in preventing the propagation of any fractures that might be caused by the high pressures needed to keep the CO_2 gas in a liquid state and to overcome the formation pressures during the injection process.

REGIONAL SETTING

The EHOF is located along the southwest edge of the San Joaquin Valley, approximately 26 miles (42 Kilometers [km]) southwest of Bakersfield in western Kern County, California. The entire EHOF is approximately 48,000 acres. The EHOF was originally developed as part of the federal Naval Petroleum Reserves. This area is situated immediately south of, and contiguous with, the Lokern Area of Critical Environmental Concern (ACEC) a part of which (3,111 acres) is controlled by the Bureau of Land Management (BLM). Portions of this surrounding area (2,050 acres) are managed as conservation areas by the Center for Natural Lands Management (CNLM) and OEHI (formerly Plains Exploration and Production Company and Nuevo Energy Company) Habitat Management Lands (200 acres). The remainder is owned by Chevron Corporation and others. The city of Buttonwillow is located directly to the north. McKittrick Valley and portions of Buena Vista Valley, with Highway 33 running NW-SE, are to the west. The cities of McKittrick and Derby Acres are located along Highway 33. Approximately ten miles to the west and across the Temblor Range is the Carrizo Plain National Monument (199,030 acres).

To the south of the EHOF is the Buena Vista Valley, the majority of which is within another Naval Petroleum Reserve oil field. The City of Taft is located approximately seven-miles to the south. Mostly undeveloped areas are located along Highway 119 to the southeast of EHOF. Lands to the immediate east include Coles Levee Ecological Preserve (6,059 acres), Kern Water Bank Authority (19,900 acres), Tule Elk Reserve State Park and the Kern River. The California Aqueduct and the West Side Canal converge and flow along the north and eastern boundary of EHOF, as does the Kern River. The Buena Vista Lake Bed is located immediately southeast of Highway 119. Bakersfield is approximately 26 miles to the northeast. The EHOF is circumscribed by Highway 5 to the north and east, Highways 119 and 33 to the south, Highway 33 to the west and Highway 58 to the north. Elk Hills Road runs north and south and bisects the Project area.

GEOLOGIC SETTING

The EHOF is located in the Great Valley geomorphic province. The Great Valley Province is characterized by a large northwest trending valley bounded by the Sierra Nevada province to the east and south, the Klamath Mountains province to the north, the Cascade Range province to the northeast, and the Coast Range province to the west. The Great Valley Province is filled with thick sediments eroded from the surrounding mountain ranges. The Great Valley province is underlain by a thick (up to 80,000 feet thick) sequence of sedimentary units (the Great Valley Sequence) which are Jurassic age or younger. The valley is an asymmetrical synclinal trough with a more gently dipping eastern limb. The Great Valley is divided into two halves. The northern half is the Sacramento Valley (containing the Sacramento Rivers) and the southern half is the San Joaquin Valley (containing the San Joaquin River). These rivers converge at the Sacramento/San Joaquin Delta and eventually flow into San Francisco Bay.

The project site is located on the western side of the San Joaquin Valley. The San Joaquin Valley is filled with thick Mesozoic and Tertiary marine and non-marine sediments covered by a relatively thin veneer of Quaternary alluvial sediments (Bailey 1966). Kettleman Hills, Elk Hills, and Buena Vista Hills provide the only significant topographic relief in the San Joaquin Valley portion of the Great Valley province (Stantec 2012).

Prior to the early Eocene epoch the bulk of the province was covered by seas. As the seas withdrew, increasing terrestrial sediments were deposited from the erosion of the Sierra Nevada to the east. During the Eocene there was uplift on the margins of the province causing the seas to gradually recede. During this time the Stockton Arch (the division between the northern and southern parts of the province) was also rising. Subsidence of the valley during late Eocene time caused the seas to again inundate the province. As the valley continued to fill with sediments, the seas occupied smaller areas. By the end of the Pliocene the seas had finally withdrawn for the last time from the southwestern portion of the province, the last area to be submerged. The last large lake to occupy the Great Valley Province was Lake Corcoran, about 600,000 years ago (URS, 2008). Lake Corcoran covered much of the western part of the San Joaquin Valley. The resulting Corcoran Clay (composed of fine clays, volcanic ash, and diatomite) covers more than 5,000 square miles and forms an extensive aquaclude creating a major confined aquifer (Stantec 2012).

The EHOF is located near the south-western edge of the San Joaquin Valley, approximately 25 miles southwest of the city of Bakersfield in Kern County, California. At the surface, the EHOF is manifest as a large WNW-ESE trending anticlinal structure, approximately 17 miles long and over 7 miles wide. With increasing depth, the structure sub-divides into three distinct anticlines, separated at depth by high-angle reverse faults. The anticlines are believed to have formed in a transpressional regime associated with formation of the San Andreas Fault, beginning in the Middle Miocene, which began approximately 16 million years ago (Callaway and Rennie Jr., 1991).

The highest elevation in the Elk Hills is 1,551 feet above mean sea level, which is between 1,000 and 1,200 feet above the floor of the San Joaquin Valley. The Tertiary (Tulare Formation) and Quaternary-aged deposits underlying the Elk Hills and nearby areas are up to 24,000 feet thick (U.S. Department of Energy [DOE], 1997).
The Tulare Formation lies at the surface of Elk Hills and consists of gravel, sand, and silt derived from erosion of the Monterey Formation exposed in the Temblor Range to the west. (Stantec 2012). Lithologically, the Tulare Formation consists of argillaceous sand and silt deposits with lenses of coarse sand and gravel. Conglomerate units do occur, but are rare overall.

The Monterey formation includes the Stevens oil-saturated sands targeted in Elk Hills for miscible-CO_2 oil recovery. Major Stevens reservoirs include the Main Body B (MBB), 26R, W31S, 24Z, 2B, A1A6, and T&N pools. Reservoir properties of the Stevens sands are good, and have led to many decades of oil production. The 24Z sand fills an anticline between 4,500 and 6,000 ft BGL (Below Ground Level) and is overlain by the Reef Ridge shale which is over 500 ft thick. The sand porosity is about 20–25 percent, and its permeability averages 150 millidarcy. The Stevens sands have net reservoir thickness of up to 1,000 ft, making them in principle a good target for CO_2 injection, if the residual oil saturation is sufficiently high (OXY, 2010a).

The Monterey Formation is overlain by the thick “Maricopa” or “Monterey Shale” or “Reef Ridge Shale” that was described in (USGS, 1932, Pages 39 and 40) for the first time:

> The Maricopa shale unconformably underlies the Etchegoin formation along the mountain front. It is the "brown shale" of drillers and is regarded by many as the source of the oil in the fields along the west and south sides of the valley. On the flanks and crest of the Temblor Range it is divided, as mapped and described by Pack,4 into a lower part consisting principally of mud shales, siliceous shale, and diatomite and an upper part comprising chiefly soft, punk diatomite and coarse detrital deposits. Many of the beds carry diatoms, radiolarians, and sponge spicules, and others carry foraminifers. At its type locality near Maricopa the thickness of the Etchegoin formation and Maricopa shale in the Sunset-Midway field. Many of the oil operators prefer to use the terms " Monterey shale" and "Santa Margarita formation," as used by Arnold and Johnson in an early report, for the beds lumped by Pack as Maricopa shale. The coarse detrital beds in the Santa Margarita formation indicate a pronounced change of some kind, presumably an elevation of the adjoining mountains. The sea began to withdraw as these beds were laid down. There is some evidence that during Santa Margarita time minor folds had begun to form. Maricopa shale is 4,800 feet, but the maximum thickness at the south end of the valley is undoubtedly considerably greater….

Staff notes that based on the above quote from USGS, Etchegoin is stratigraphically located above the Monterey. The name “Reef Ridge Shale” was proposed by Barbat and Johnson (1933, p. 239, 1934, p. 3-5) for a distinctive soft blue (brown weathering) clay shale poorly exposed on the northeast side of Reef Ridge, stratigraphically above the brown siliceous shale of the McLure Shale Member. These workers noted that the distinctive character of the strata was first recognized by Arnold and Anderson (in the quote above), who included the rocks as an upper division of the Santa Margarita (see Siegfus, 1939 and references therein).

EOR COMPONENT DESCRIPTION

The original Project Description provided by ManageTech (2010) identified a projected total of 550 injection and production wells. Upon additional evaluation, OEHI increased the number of projected wells to 720 (309 injection wells and 411 production wells). OEHI has designed the project to utilize existing wells to the maximum extent feasible. OEHI estimated that 570 of the 720 wells necessary for the proposed project will utilize pre-existing well locations. The remaining 150 wells will be new installations. The wells would be utilized in an alternating fashion to inject the CO_2 gas and to extract oil. The permit application submitted by OEHI to DOGGR for Class II wells included wells in 25 patterns. Applications to permit new wells would be submitted as the need arises for them to be installed.

According to OEHI, approximately 1,231 wells penetrate the Stevens reservoirs. Currently 1,021 active wells penetrate the Reef Ridge Shale in the 31S structure; 128 wells are permitted by California's Division of Oil, Gas and Geothermal Resources (DOGGR) as underground injection control (UIC) Class II injection wells and 749 wells are permitted by DOGGR as production wells. In addition there are 144 wells that can be both producers and injectors at the completion level within different reservoirs, or have been "plugged and abandoned" in one reservoir, but are active in another, or have changed well type. There are 178 inactive injection and production wells, 22 injection and production wells that have been "plugged and abandoned" according to regulatory requirements, and 10 wells that are shut in.

The presence of such a large number of well bores in the area as seismically active as the project site raises the potential for seismic activities to damage some of those well bores, thereby creating leak pathways for the injected CO_2. The structural integrity of existing and proposed new wells for injection and extraction for EOR is also a concern because relatively high pressures will be used.

Carbon Capture & Storage (CCS) projects around the world

OEHI believes the combination of multiple sandstone reservoirs interbedded with impermeable shale seals within the three large anticlines make the EHOF one of the most suitable locations in North America for the extraction of hydrocarbons and sequestration of CO2. Staff notes there are a number of other projects around the world that are currently underway in the design and construction process for CCS. The MIT website, sequestration.mit.edu/, keeps track of most existing and planned CCS projects around the world, and divides them into two classes: (1) electric power plant projects and (2) non-electric power plant projects that are mostly CO_2 injection EOR projects or CO_2 removal from methane projects.

In the first category, six projects are listed in the U.S., two in Canada, 12 in the European Union, two in Norway, three in the rest of the world, and there are 18 pilot projects.

Among the U.S. projects, a 65 percent sequestration project for a 582 MW lignite and natural gas power plant in Mississippi is under construction and may become operational in 2014. The project will sequester 3.5 MT/y of CO_2 for 22 years at an estimated cost of \$2.4 billion. This cost excludes Allowance for Funds Used During Construction (AFUDC) and includes incentives. Mississippi Power has received a \$270 million grant from the Department of Energy for the project (CCPI Phase 2) and \$133 million in investment tax credits approved by the Internal Revenue Service. HECA and four other projects are in planning stages.

When completed in 2014, the Canadian Boundary Dam 110 MW project will export its CO_2 to an EOR project via a 100 km pipeline. The total cost of the project is estimated to be \$1.24 billion. The Boundary Dam project received \$240 million from the federal government in 2011, of which about \$180 million has already been spent. The provincial government in Saskatchewan is also supporting the project. Revenue from the sale of CO_2 is expected to offset the project costs. Sulfur dioxide (SO_2) will also be captured and sold.

In EU, a small pilot project in England injects 100 T/y of CO_2 and may be expanded to 1.7 MT in the future.

In Norway, an up to 100,000 T/y Mongstad pilot project has been in operation since May 2012. This project may be expanded to 1.7 Mt/y in the future at a cost estimated to be 6 billion kroner (\$1.02 billion).

Among the 18 small pilot projects (Mongstad is listed again), 14 were operated in the past, or are operational now.

In summary, among the 42 unique CCS projects around the world designated as electric power generation, none are operational, 3 may be expanded in the future from the pilot to full scale, and all but one will be smaller than HECA.

In the second category, CCS/EOR projects, 10 projects are listed in the US (HECA excluded), six in Canada, five in Europe, and five in the rest of the world.

Of the U.S. projects, four to six are either operational or were operated. The La Barge, Wyoming project, operated by Exxon Mobil, is designed to inject 6 MT/y of CO_2. Production of natural gas from the La Barge field began in 1986. This gas contains high concentrations of CO_2. The Shute Creek Treating Facility (SCTF) processes the gas produced from the La Barge field. The gas composition entering Shute Creek is 65 percent CO_2, 21 percent methane, 7 percent nitrogen, 5 percent hydrogen sulfide (H_2S) and 0.6 percent helium. The SCTF separates CO_2, methane, and helium for sale and removes hydrogen sulfide for disposal. This ongoing project is three times larger than the HECA project would be.

In Canada of the six projects, two are operational. The Weyburn project is injecting 1 MT/y of CO_2 into a depleted oilfield.

In Europe, the oldest CO_2 separation project in Sleipner, Norway, started in 1996. This project injects 1 MT/y of CO_2 separated from natural gas.

In the rest of the world, of the five listed projects, four were either operated or are operational. The Shell Gorgon project in Australia is under development and will inject 3.3 MT/y. This is the world's largest sequestration project and is supported by Australia's Government. The Australian Government accepted liability for Gorgon project (August 2009). Construction started November 2009. All necessary permits and approvals have been obtained (October 2010).

In October 2012, Australian's energy minister Martin Ferguson, announced that the Gorgon project was still on track for injection to start in 2015. At this time the project was 55 percent complete.

METHOD FOR DETERMINING SIGNIFICANCE OF IMPACTS

Injection of CO_2 can have impacts in terms of induced seismic activity, contamination of underground sources of drinking water (USDW) and/or air quality. For seismic impacts, staff uses the prevailing seismic activity in the region as the background conditions and compares the induced seismic activity with the prevailing activity to determine if there would be significant impact. If the magnitude of the induced seismic activity exceeds the prevailing magnitudes then staff concludes that the impact is significant. For impacts to USDWs staff considers any leak that has the potential to reach a USDW as a significant impact. For air quality impacts, any potential leaks of CO_2 would contribute to the greenhouse gas emissions. Since one of the purposes of the injection of the CO_2 is to reduce the total emissions to comply with the SB1368 EPS any potential leaks could lead to violation of the compliance requirements of SB1368.

GEOLOGIC CHARACTERIZATION AND LEAKAGE PATHWAYS

In the presence of the numerous surface faults in the region staff is concerned that increased pore pressure associated with the injection of the carbon dioxide can cause increased stresses on faults, which can cause those faults to slip and the apertures to dilate and allow for leakage of CO_2. In addition to the surface faults, and given the nature of the area and the fact that it is composed of anticlinal formation on one side and synclinal formation on the opposite side, it is likely that there exist numerous subsurface faults and fractures beneath the ground surface. Staff analyzed whether faults and fractures in the EHOF could be conduits for leakage of CO_2 to the surface. Two anticline structures (31S and NWS) would be used as primary injection structures by the OEHI CO_2 EOR project and a third anticline structure (29R) will be used as a backup. These structures form bathymetric highpoints on the deep inland marine surface (seafloor location and extent of four faults that helped to form these anticlines. Four faults penetrate the Reef Ridge Shale and one of them, 5R (which is outside the Oxy CO_2 EOR component area), fully transects this formation. Based on site-specific studies, OEHI has concluded that the vertical extent of faults 1R, 2R and 3R is limited and any penetration of the confining zone of the Reef Ridge Shale is minimal and does not present a likely pathway for leakage to the surface.

Further discussion of this analysis is presented in Section 3.1.2.2 of the OEHI MRV (Oxy, 2012), which discusses the Reef Ridge Shale characterization studies conducted by OEHI. OEHI's 3-D seismic data provides further evidence of the sealing characteristics of the Reef Ridge Shale. The data were processed using pre-stack depth migration which produces superior imaging in steeply dipping beds, such as on the flanks of the Stevens structures. Analysis of these data indicates that faults above and below the Reef Ridge Shale terminate before penetrating the seal.

The Stevens reservoirs are contained within three geologic structures that are completely overlain by the Reef Ridge Shale, which serves as the primary seal. OEHI used the following methods as evidence to confirm the sealing characteristics of the Reef Ridge Shale:

1. *Physical Rock Characteristics of the Reef Ridge Shale,*
2. *Fluid Contacts and Reservoir Pressure Depletion,*
3. *Core Analysis of the Reef Ridge Shale,*
4. *Seismic Control,*
5. *Geochemical Analysis, and*
6. *Geomechanical Analysis.*

OEHI's methods are summarized below:

1. Physical Rock Characteristics of the Reef Ridge Shale

The significant areal extent and vertical thickness of the Reef Ridge Shale are the two main factors in its effectiveness as a seal for containing injected CO_2. The Reef Ridge Shale covers an area that is many times larger than the planned areal extent of the OEHI CO_2 EOR component. The Reef Ridge Shale is also very thick, ranging from 750 to 1,400 feet in thickness over the injection zones in the NWS and 31S structures.

2. Waterflooding and Fluid Contacts Analysis

Waterflooding is currently being conducted under a set of Class II UIC permits issued by DOGGR. To date, more than 830 million barrels of water have been injected and there are currently about 150 active water-injection wells and 580 active oil and gas production wells in the Stevens reservoirs. OEHI indicated that it has not detected any evidence of communication between zones. This lack of communication between the zones, confirmed by publicly-available production and pressure records reported to DOGGR, indicates that they are separated from each other even when both reservoirs are pressured for production.

3. Core Analysis

In 2000, Reef Ridge Shale core samples were collected from the 31S structure. These core samples demonstrated two important features. First, X-ray diffraction of the core indicated that the predominant secondary mineral is clay, which inhibits the Reef Ridge Shale's ability to fracture. Second, low permeability was verified by the absence of oil saturation. This may indicate that as zones below the Reef Ridge Shale were being charged with hydrocarbons, the permeability of the Reef Ridge Shale was sufficiently low to prevent hydrocarbon migration through the shale.

4. Seismic Control

A 3-D seismic survey was performed from 1999 – 2000, and covered nearly 70 square miles in the Elk Hills Unit (EHU). The data were processed using pre-stack depth migration which produces superior imaging in steeply dipping beds, such as on the flanks of the Stevens structures. Analyzing these data, OEHI concluded that faults above and below the Reef Ridge Shale terminate before penetrating the seal.

Since 1990, 129 naturally occurring earthquakes have been recorded with a magnitude greater than 3.0 within a 60-mile (100-km) radius of the EHOF. The vast majority of these have occurred along the White Wolf Fault approximately 30 miles southeast of the EHOF (Southern California Earthquake Data Center web site). The historical data (long-term and short-term) indicate that naturally occurring seismic activity throughout history has not compromised the sealing integrity of the Reef Ridge Shale.

5. Geochemical Analysis

Geochemical data collected by OEHI revealed five distinct oil families sourced from the Miocene Monterey Formation and tied to stratigraphic intervals. The differences between the distinct geochemical compositions of the Stevens and shallow oil zone (SOZ) oils among the other oil "families" identified corresponds to separate reservoir horizons and suggests "minimal upsection, [and] cross stratigraphic migration." OEHI concludes that the hydrocarbons present in the SOZ reservoirs are from "another Monterey source facies (perhaps the youngest) with charging of Pliocene reservoirs" and not the result of upward movement from the older Miocene reservoirs.

6. Geomechanical Analysis

OEHI developed a full-field simulation model which allowed OEHI to assess the integrity of the Reef Ridge Shale under various injection-volume and pressure scenarios over extended periods of time.

Staff believes this is significant evidence that suggest the likelihood there would be reactivation of faults or dilation of fractures that would extend to the surface is low.

The EHOF is in a compressive tectonic stress field generated by the San Andreas Fault (Patzek 2011). Since no principal stress measurements are available for the OEHI project area, staff had to rely on information from two nearby analogs, the South Belridge Diatomite and Brown Shale, and the Lost Hills Diatomite and Shale oil and gas fields for analysis of field stresses. Due to the nature of the geology of the formation at the site and the distribution of different types of forces, stresses in these two fields cross-over, meaning that the vertical stress is larger than the horizontal stress for some depth and then the situation reverses and the horizontal stress becomes larger than the vertical stress below that depth. Thus, with increasing depth the vertical stress becomes the minimum principal stress. Therefore, the fault character in Elk Hills ought to change with depth from strike-slip faulting to reverse or thrust faulting.

When vertical stress is the minimum principal stress and the injection pressure is very high (higher than the overburden pressure), this can lead to the creation of horizontal fractures. At shallower depths, possible fractures created by injection would be vertical. Therefore, the injection pressures of CO_2 and water must be monitored carefully by OEHI over the duration of the project to avoid unwanted fractures that might compromise the reservoir seals. It should be pointed out, however, that thick layers of the more elastic shales overlying the OEHI CO_2 injection interval act as elastic sheets that effectively prevent substantial fracture extensions beyond the reservoir interval. Therefore, the only place where the geologic seal might fail is through the preexisting faults that extend vertically above the injection interval and become activated by the high injection pressure.

A fault might slide if the ratio of the shear stress resolved onto the sliding fault plane and the effective normal stress on the fault is equal to the coefficient of friction, which almost universally is about 0.6 (Hubbert and Rubey, 1959). Note that for faults where the cohesive strength is small, their slip criterion can be deduced directly from the Mohr-Coulomb law (Patzek 2011). Therefore, with the increasing injection pressures of CO_2 and water, some faults may slip, causing seismic activity. Most, if not all, of this seismic activity would be so weak that it is unlikely, if not impossible, to be noticed by a surface observer. It is therefore extremely unlikely that the integrity of the overlying shales would be compromised by the injection activities. Also, when injection activities are completed and the excess pore pressure dissipates through the formation, most of the faults that might have been caused to open by the injection activities would close and reseal.

In addition, staff agrees with OEHI that natural seismicity is not likely to impact field operations and is highly unlikely to lead to leakage to the surface of any injected CO_2 from the EHOF. This assessment is based on decades of historical data for earthquake effects on wells in oil and gas operations in Southern California. It is also based on the geological setting of the EHOF, which is in relatively soft and shallow sediments.

With respect to natural seismic events, abundant historical data and information indicate that such events do not constitute a significant threat of leakage to the surface. The southern San Joaquin Valley area has a 100-year history of being a prolific oil and gas producing region with about 70 medium-to-very-large-scale oil and gas fields. There are more than 58,000 deep production and injection wells in Kern and Inyo Counties. These existing wells have experienced decades of seismic activity with no significant release of gas, oil or water to the surface during earthquakes.

Furthermore, the drilled thickness of the Reef Ridge Shale in well 324-19R is 633 feet. The Reef Ridge Shale is also shown in Figures 14.3 and 14.4 in USGS (2007). It is unlikely that this thick pliable shale will fail across the CO_2 injection site in the EHOF, unless there is a failure of a large fault caused by severe overpressurization (significantly above the overburden pressure) of the sands into which CO_2 would be injected. Such overpressurization is illegal and is unlikely to happen over a prolonged time and large reservoir area. Staff concludes that given the nature of the faults and fractures and the geology of the EHOF, CO_2 leakage from the EOR component in terms of fault mobilization and dilation of fractures would be less than significant.

Natural and Induced Seismicity

The EHOF is located in the most seismically active area in the US. The San Andreas Fault is located only about 12 miles southwest of the EOR site. As discussed in detail in the **Geology and Paleontology** section, there are a number of major faults within 70 miles of the oil field. There are several faults of type A and type B, where type A faults have a slip rate greater than 5mm/year and are capable of producing an earthquake of magnitude 7.0 or greater and type B faults which have a slip rate of 2 to 5 mm/year and are capable of producing an earthquake of magnitude 6.5-7.0 on the Richter scale. There are also type C faults with slip rates less than 2 mm/year that are more than 20 miles away from the EOR and sequestration site and would have no effect on the site.

The applicant believes that natural seismicity is not likely to impact field operations and is highly unlikely to lead to leakage to the surface of any injected CO_2 from the EHOF. As indicated by the applicant, this assessment is based on decades of historical data for earthquake effects on wells in oil and gas operations in Southern California. It is also based on the geological setting of the EHOF, which is in relatively soft and shallow sediments. They also note that the southern San Joaquin Valley area has a 100-year history of being a prolific oil and gas producing region with about 70 medium-to-very-large-scale oil and gas fields. There are more than 58,000 deep production and injection wells in Kern and Inyo counties. These existing wells have experienced decades of seismic activity with no significant release of gas, oil or water to the surface during earthquakes.

Staff concurs that most earthquakes with a magnitude 6 and above in California occur at depths of 6 miles or more in brittle basement rock. Since the proposed injection zones at EHU are less than 2 miles deep there would appear to be a significant separation between major earthquake sources and the injection reservoirs. The Los Angeles Basin contains more than 80 oil and gas fields and several natural gas storage fields. The fact that it has experienced more than 20 major earthquakes (greater than magnitude 6), some directly adjacent to major gas fields and natural gas storage fields, with no damaging release of gas to the surface is compelling evidence that potential impacts could be limited.

Fluid and gas injection is known to induce microscopic seismic activities. However, the risk of induced seismicity from CO_2 EOR has been assessed to be very low. Injection operations have been observed to cause low level seismic occurrences at a limited number of oil and gas fields around the world, including some in California (most notably the Geysers geothermal operations).

Generally, the low risk of induced seismicity is supported by the results of a comprehensive study that reviewed data on low-level seismic effects related to underground injection operations designed to hydraulically fracture shale formations. Warpinski et al. 2012), The study covered several thousand shale fracture treatments in various North American shale basins and the largest micro earth tremor recorded had a measured magnitude of about 0.8. A deep earthquake of this magnitude would not be felt at the surface of the earth, and would not cause surface damage.

McGarr et al., 2002, have analyzed dozens of earthquakes causes by dams, liquid waste injection, mines, and production/injection in oil and gas reservoirs. They note that the upper bound of the correlation between the characteristic size of a human activity and the associated anthropogenic earthquakes has the slope of two. This correlation suggests that for an activity 10 km in extent, the maximum credible earthquake would have a magnitude near 6. They also caution that no seismic activity is recorded in many instances where human activities affect the earth stresses over large areas, such as below many impounded water reservoirs.

The Nature Journal (www.nature.com/news/method-predicts-size-of-fracking-earthquakes-1.9608) wrote about McGarr's approach and published the following rule of thumb:

> The researchers found a proportional relationship between the volume of fluid injected and the magnitude of the earthquake.
>
> "If you inject about 10,000 cubic meters, then the maximum sized earthquake would be about a magnitude 3.3," says McGarr. Every time the volume of water doubles, the maximum magnitude of any quake rises by roughly 0.4. "The earthquakes may end up being much smaller, but you want to be prepared for the worst-case scenario," says McGarr. The relationship is straightforward, but it is the first time that anyone has quantified it, he adds."

The annual injection of CO_2 in the EHOF will be 2 million tons, equivalent to 1 million cubic meters of water. This is 7 doublings from 10,000 cubic meters of water. Thus the maximum earthquake magnitude might be 3.3+7x0.4 = 6. It should be noted, however, that oil, water and gas will be produced at the same time, and therefore the maximum possible magnitude will be much less, likely less than 3.3.

It should be stressed here that the calculation above provides an estimate of a remote possibility, not of a real earthquake. Magnitude 6.0 earthquakes do occur in the Parkfield area in California, not far from the EHOF. Such earthquakes have occurred on the Parkfield section of the San Andreas fault at fairly regular intervals - in 1857, 1881, 1901, 1922, 1934, and 1966. While little is known about the first three shocks, available data suggest that all six earthquakes may have been "characteristic" in the sense that they occurred with some regularity (mean recurrence period of about 22 years) and may have repeatedly ruptured the same area on the fault. (earthquake.usgs.gov/research/parkfield/hist.php). The last magnitude 6 earthquake occurred in Parkfield in 2004, which was long overdue. In summary, staff believes that it is very unlikely, if not impossible, that anthropogenic earthquakes will exceed natural earthquakes in the EHOF.

While there is no history of induced seismicity at Elk Hills, the possibility cannot be ruled out completely. As discussed above, any such induced seismicity events would likely be less than magnitude 4, considering the geologic setting, areal extent and depth of proposed operations, and anticipated pressure and stress changes. Seismic events of magnitudes between 3 and 4 would be felt in the local area but should not cause structural damage to facilities and buildings.

Furthermore, as discussed in the **Geology and Paleontology** section, the maximum anticipated peak acceleration produced by the injection is on the order of 0.01 g, which is at least an order of magnitude less intense than site accelerations associated with maximum credible earthquakes on major faults mapped in the vicinity of the project site. Since induced seismic events are not large enough to cause structural damage, staff agrees with the conclusion reached by OEHI that a release of CO_2 from the subsurface due to induced seismicity is unlikely.

Lateral Spill

When a liquid is poured into a container it starts to fill it from the bottom up until it reaches the lowest spill over point on the edge of the container where the container would not hold any more of the liquid. However, if a fluid is buoyant (lighter than the ambient fluid) then it will rise to the top, and unless there is a barrier that prevents it from rising it would it would dissipate up into the ambient fluid. And in the presence of a lid (an inverted bowl) that holds the fluid in place it would keep filling the space from the top down until it reaches a point where it can escape out of the lid. This point is known as the lateral spill point (LSP).

The CO_2 injected in the EHOF would be held in place by the dome-shaped shale formation. Since the injected CO_2 is more buoyant than formation fluids it tends to rise in the target formation until it reaches the ceiling of the structural or stratigraphic trap. This trap has held hydrocarbons for millions of years. Hypothetically, more CO_2 could be injected into a structural or stratigraphic trap than that trap could hold, filling the space from the top downward until the CO_2 flows out of the trap through the lowermost “spill point.” However, given the physical characteristics of the 31S and NWS structures and the relatively small volume of CO_2 to be injected compared to the capacity of the Stevens reservoirs on the 31S and NWS structures, there are no reasonable injection scenarios that would lead to overfilling the Stevens reservoir with CO_2 to result in leakage at lateral spill points.

As was shown in the MRV plan submitted by OEHI, the oil bearing layers within the Stevens reservoirs in the 31S structure are above the free water levels. Beneath the free water level there is no residual oil saturation (i.e. no oil to be recovered through CO_2 EOR). The left lateral spill point (LSP) was shown to be on the left flank of the 31S structure. The right LSP is located very far away from the injection point. However, both LSPs were shown by OEHI to lie below the free-water level, which means that water would act as a barrier for the CO_2 to escape even if the amount injected was large enough to fill the whole available pore space and reach the water surface.

With respect to the volume of the CO_2 to be injected, the OEHI CO_2 EOR Project would produce roughly the same quantity of fluids as are injected. As stated by OEHI, this operating practice prevents overfilling of the reservoir to the spill point with CO_2. Moreover, the quantity of CO_2 to be injected over the 20-year life of the OEHI CO_2 EOR project is equivalent to less than five percent (approximately) of the useable reservoir pore volume, (i.e., the pore volume located above the free-water levels). As the full field simulation conducted by OEHI indicated, it is predicted that a majority of the injected CO_2 would be contained in the MBB portion of the Stevens reservoirs which is the main target zone for injection.

In addition to the foregoing, the Reef Ridge Shale extends hundreds of miles beyond the EHOF. If CO_2 were to migrate beyond the LSP's, it would be sequestered because of the influence of other natural trapping mechanisms including mineralization and residual trapping.

In light of the preceding analysis, staff concurs with OEHI that the risk of overfill through lateral spill points is less than significant.

Ground Subsidence

Ground subsidence can result from activities that cause a lowering of the total reservoir pressure. Oil and gas extraction, as well as groundwater pumping are examples of activities that have been known to cause ground subsidence. However, the magnitude of subsidence depends on several factors including the geologic structure of the subsurface domain.

Oil and gas extraction operations have been taking place at the EHOF for decades. However, there has been no documented evidence that significant subsidence has occurred at the site. This could be attributed to the dome shape and large thickness of the shale formations overlying the extraction zones. The dome shape offers resistance to deflection under increased vertical loading that can cause increases in the net downward forces acting on the formation when the pressure below the formation is decreased by extraction activities.

While conventional oil and gas extraction activities remove more fluids from a reservoir than is put back, EOR activities are more likely to result in replacing all volumes of fluids extracted with other fluids such as water and carbon dioxide. This means that it is likely that no net decrease will be experienced by reservoir pressures. If anything, there might even be a slight increase in reservoir pressure after equilibrium has been attained since injection pressures have to be higher than native pressures for the injected fluids to enter the formation. Thus staff concludes that it is unlikely for the CO_2 EOR activities at the EHOF to result in any significant ground subsidence.

Regulations Governing the Injection Activities

OEHI would be injecting the CO_2 pursuant to the Class II permit for the existing wells and would obtain new Class II permits from DOGGR for new wells. However, Class II well requirements are not intended for injecting CO_2 for sequestration purposes.

Since leaks of injected CO_2 have the potential to contaminate underground sources of drinking water (USDW), the U.S. EPA, with mandate under the Clean Water Act, has issued regulations to control injection wells intended for long term storage of CO_2 in terms of construction, operation, monitoring, plugging, post-injection site care (PISC), and closure, as well as financial responsibility for any maintenance and correction action plans. The U.S. EPA regulations were codified under 40 CFR part 146 subpart H commencing with subsection 146.81. The Class VI regulations include specific requirements for the construction of new wells and retrofitting of existing wells, and also for the operation and monitoring of the wells during and after termination of the injection activities. Some of the prominent differences in the requirement for the wells in the two classes are listed below in **Carbon Sequestration and Greenhouse Gas Emissions Table 13.**

Carbon Sequestration and Greenhouse Gas Emissions Table 13

Comparison of Requirements for Class II and Class VI Wells

Requirement Type	Class VI Regulatory Citations	Class II Requirements (Summary) and Regulatory Citations	Additional Class VI Requirements
Required permit information	40 CFR 146.82	Information is required on the local geologic structure and faults; maps and cross sections of the regional geology, including the Area of Review (AoR); planned formation testing, construction, operating, and monitoring procedures; and a demonstration of financial responsibility to close the well. (40 CFR 146.24)	Class VI regulations require information on baseline geochemistry and seismic history. Class VI requirements include several project-specific plans not required for Class II (e.g., post-injection site care and site closure, and comprehensive emergency and remedial response plans). Class VI requirements include periodic updates to certain plans.
Minimum criteria for siting	40 CFR 146.83	Demonstrate the presence of injection and confining zones. Confining zone must be free of known open faults or fractures within the AoR. (40 CFR 146.22)	Class VI regulations permit the UIC Program Director to require characterization of additional confining zones.

Requirement Type	Class VI Regulatory Citations	Class II Requirements (Summary) and Regulatory Citations	Additional Class VI Requirements
Area of review and corrective action	40 CFR 146.84	Define the AoR (based on the zone of endangering influence) as a fixed radius of at least ¼ mile or calculate by a formula. (40 CFR 146.6) Identify and address improperly completed or plugged wells in the AoR. (40 CFR 146.24(c)(6))	Class VI regulations require computational modeling for AoR and periodic reevaluation of the AoR and Corrective Action Plan. Class VI regulations require the use of carbon dioxide-compatible materials for corrective action. Class VI regulations permit phased corrective action.
Financial responsibility	40 CFR 146.85	Demonstrate and maintain financial responsibility to close, plug, or abandon the well. (40 CFR 146.24(a)(9))	Class VI regulations have requirements for financial responsibility to address corrective action, post-injection site care and site closure, or emergency and remedial response. Class VI regulations have requirements for allowable instruments.
Injection well construction	40 CFR 146.86	Wells must be constructed to prevent movement of fluids into or between USDWs. Casing and cementing must be designed for the life expectancy of the well. (40 CFR 146.22)	Class VI regulations specify the depths of casing strings and cementing to the surface. Class VI regulations require compatibility of well materials with fluids with which they would come into contact.
Logging, sampling, and testing prior to injection well operation	40 CFR 146.87	Class II and Class VI regulations include similar requirements for logging, sampling and testing (40 CFR 146.22 (f)).	Class VI regulations require cores to be taken and a log analyst's report to be submitted. Class VI regulations require tests to verify the hydrogeologic characteristics of the injection zone (e.g., pressure fall-off test and pump test or injectivity tests). The owner or operator must provide the UIC Program Director the opportunity to witness all logging and testing for a Class VI project.

Requirement Type	Class VI Regulatory Citations	Class II Requirements (Summary) and Regulatory Citations	Additional Class VI Requirements
Injection well operating requirements	40 CFR 146.88	Injection between the outermost casing protecting USDWs and the well bore is prohibited. (40 CFR 146.23(a)(2)) Injection pressures may not initiate or propagate fractures in the confining zone or cause injection or formation fluid movement into USDWs. (40 CFR 146.23(a)(1))	Class VI regulations include a pressure limitation. Class VI regulations include a requirement to install continuous recording devices, alarms, and surface or down-hole shut-off systems or other safety devices. Class VI regulations require specific procedures if a loss of mechanical integrity is discovered or a shutdown (i.e., down-hole or at the surface) is triggered.
Mechanical integrity testing (MIT)	40 CFR 146.89	Conduct internal and external MIT at least once every five years (40 CFR 146.23(b)(3))	Class VI regulations require continuous monitoring to demonstrate internal mechanical integrity. A Class VI project must conduct annual external mechanical integrity testing.
Testing and monitoring requirements	40 CFR 146.90	Monitor injected fluids. Observe injection pressure, flow rate, and cumulative volume at least once every 30 days (40 CFR 146.23(b)(1-2))	In addition to the requirements for Class II wells, Class VI regulations require: • Continuous monitoring of injected fluids, injection pressure, flow rate, and cumulative volume; • Plume and pressure front tracking; • Surface air monitoring and soil monitoring, at Director's discretion; and • Corrosion monitoring and ground water quality monitoring.
Reporting requirements	40 CFR 146.91	Submit semi-annual monitoring report. (40 CFR 146.23(c))	Class VI require: • Semi-annual monitoring report; • Electronic reporting; and • Record-keeping.
Injection well plugging	40 CFR 146.92	Well must be plugged in a manner which will not allow the movement of fluids either into or between a USDW. (40 CFR 146.10(a)(1))	Class VI regulations require compatibility of the plugging material with fluids with which the plugs may be expected to come into contact. Class VI regulations specify pre-plugging activities, notice of intent to plug, and a plugging report.
Post-injection site care and site closure	40 CFR 146.93	None.	Class VI regulations require post-injection site care or monitoring; no such requirements exist for Class II.

Requirement Type	Class VI Regulatory Citations	Class II Requirements (Summary) and Regulatory Citations	Additional Class VI Requirements
Emergency and remedial response	40 CFR 146.94	Submit contingency plans to cope with well failures so as to prevent migration of fluids into a USDW. (40 CFR 146.24(b)(4))	Class VI regulations address other potential risks in the AoR, such as risks from the pressure front.

As can be seen from the table above, there are significant differences between the requirements for wells in the two classes, particularly in the following areas:

a. Area of Review (AoR) requirements,

b. Casing and Cementing requirements,

c. Monitoring requirements.

d. Plugging and post-injection site care requirements, and

e. Financial responsibility requirements.

The more stringent requirements of the class VI permit are intended to store CO_2 in the ground and ensure that the injected CO_2 remains sequestered and also to keep track of any movement of the CO_2 underground. While the injected CO_2 is intended for EOR purposes by OEHI, HECA's goal is to reduce the total emissions to be in compliance with SB 1368 emission regulations requiring that CO_2 emissions associated with power generation not exceed 1100 lbs/MWh. In order to achieve that goal, HECA is required to demonstrate that the sequestered CO_2 remains sequestered during and after the plugging of wells and closure of the injection site. Therefore, CEC staff believes that compliance with the Class VI well requirements would ensure that the injected CO_2 would remain sequestered on a long term basis. Compliance of the project owner with the regulations for injection wells as required by Condition of Certification **GHG-3**, with the exception that the project owner would not have to obtain the actual permit, would ensure compliance with SB1368 and also that impacts from the injection of the carbon dioxide would have no significant impacts on USDWs.

Some or most of the injected CO_2 gas would come out with the extracted oil but would be separated and injected back with fresh CO_2 from HECA. The applicant proposes that any amounts of the injected CO_2 that remain in the formation, less any amounts that are detected to leak using a rigorous monitoring program, would be considered to have been permanently sequestered.

Staff believes that in order for the applicant to ensure CO_2 is being sequestered, the applicant should ensure that injection wells are constructed and operated in accordance with the more stringent requirements of Class VI wells, as detailed in COC **GHG-3**, though the applicant/user would not have to obtain the actual permits. Furthermore, if Occidental Petroleum decides to terminate EOR activities during the life time of the project while continuing to inject the CO_2 on behalf of the applicant then the injector shall be required to obtain Class VI permits for the injection wells that would be used for injection. However, if the injecting party chooses not to inject the CO_2 on behalf of the applicant then the applicant would be required to find another party to inject the CO_2

and who would be willing to comply with the requirements of **GHG-3**. Otherwise, the applicant would either have to seek permission to develop their own Class VI permitted site for sequestration and seek to amend the project to store the carbon at the alternate site, or otherwise halt operation of the power facility.

Project Operations

OEHI is expected to receive a daily maximum rate of 130 million standard cubic feet per day (mmscfd) and an annual average rate of 107 mmscfd of CO_2 or 2.2 million tons per year for use in its EOR activities. The use of this CO_2 would last for 20 years. This volume is equal to 6 percent of the 35 million tons per year of CO_2 currently injected in the U.S. by more than 100 EOR projects, mostly in Texas. This would make the OEHI CO_2 EOR component very large in comparison to existing EOR projects, equivalent to approximately 6 current CO_2 EOR projects on average.

Assuming 160 injection and extraction patterns will be used for CO_2 EOR, and that the patterns are 20 acres in size (some patterns may be only 10 acres), an upper bound on the reservoir pore volume in the EOR project area can be calculated as follows:

> 160 patterns × 20 acres/pattern × 43,560 square feet/acre × 1,000 foot depth of formation × 0.225 pore fraction / 5.615 cubic feet/barrel = 5.6 billion barrels.

The numbers used in the calculation above are approximate numbers that were chosen to be in the ball park of the OEHI's numbers. Data provided by OEHI indicated that 1.3 billion barrels of oil have been extracted from the reservoir whose pore volume has been estimated at 7.5 billion barrels. Therefore, in order to refine the calculation above to represent the numbers for the OEHI field, the result has to be scaled using numbers provided by OEHI. Scaling the rough estimate of the pore volume with the more detailed OEHI estimates of the pore volume and cumulative fluid injection, 5.6/7.5 × 1.3 = 1.0 billion reservoir barrels of fluid would have been produced from the assumed project area. This number is slightly less than the net 1.1 billion reservoir barrels of CO_2 and water injection needed for the project. However, more oil and water would be produced, which would make more pore space available for the storage of the CO_2. (OEHI made no allowance for the injected water volume.)

OEHI proposes to follow the standard field practice and use one injection well in each pattern for CO_2/water injection. A 1:1 water-alternating-gas (WAG) ratio is assumed, that is the injection of a volume of water followed by injection of the same volume of CO_2. The cycle duration would be on the order of 60 or 90 days of water injection, followed by an equal time of CO_2 injection. Because the CO_2 would be injected as slugs followed by water slugs, and a portion of the injected CO_2 would be recovered with the oil and recycled, the actual injection rate would be much higher than the amount of CO_2 received from HECA. It would take some time for the injected CO_2 to fill up some of the reservoir pore space and dissolve in oil. With time, the accumulating CO_2 would break through in almost all production wells and a new steady state would be reached, whereby the accumulated CO_2 would be produced at one end of the system, while fresh CO_2 would be injected at the same constant rate at the other end. The applicant has estimated that the maximum CO_2 injection rate (HECA import plus recycle) could be as high as 685 mmscfd near the end of production in each pattern, which is about five times the amount of CO_2 imported from HECA. (This ratio is double of the actual CO2 injected, because ½ of the wells will be injecting water, not CO2 at any given time.). The high-rate CO_2 injection over 20 years would require significant repressuring of the reservoir, which might reopen some existing critically-stressed faults, and might require an extension of the project to divert the produced CO_2 to new injection wells.

Therefore, the existing and new wells might provide potential conduits for CO_2 leaks at the surface either outside of the surface conductor casing (because of poor cement jobs), or through well annular spaces and wellheads, pumps, injection tubings and packers, joints, valves, couplings, separators, and surface pipelines. The potential for leaks would increase with project time, because of the increasing reservoir pressure and acidic conditions developing in the reservoir around the wells, as well as inevitably progressing corrosion and wear-and-tear of the field equipment.

Relying on observations made at dozens of ongoing field projects that involve CO_2 and water injection, it can be noted that the probability of a major equipment leak is very small. Furthermore, as was discussed above, and due to the presence of several thick layers of shale the potential for leaks through the geologic formation is extremely small to nonexistent. Therefore, the only significant potential for leaks that remains is through existing well bores, active and abandoned. Given the presence of a large number of well bores, OEHI would be required to create an extensive monitoring network of CO_2 sensors that would be able to detect any leaks through the well bores. OEHI stated in the Monitoring, Reporting, and Verification (MRV) plan that it has in place a sophisticated centrally controlled network to monitor for any leaks of gases that may accidentally leak through the well bores. OEHI further stated that the same network is capable of and would be utilized to detect potential leaks of injected CO_2 through the well bores, both through the casings and also through the annular space.

Staff recommends that HECA enter into an agreement with OEHI that requires installation of a robust monitoring network that is capable of detecting potential leaks of injected CO_2 from all well bores, active, shut-in, plugged, or abandoned to ensure any leaks that may occur through those well bores would be detected in accordance with condition of certification **GHG-3**. This network will provide detection of significant CO_2 leaks, which should be isolated and repaired or plugged if repair is not possible. The monitoring network should remain active for several decades.

Spill-Over Area (Injection for storage with no EOR)

In the event that injection capacity for EOR at a pattern is less than the rate of delivery of CO_2 OEHI might need to store the delivered CO_2 in a spill-over area (or back-up injection area). However, OEHI had informed EPA and DOGGR that it would not need a spill-over area since it would be doing EOR at alternating sites and thus would always have a place to inject the imported CO_2 and do EOR at the same time. Any injection of CO_2 would have to be performed in areas designated for EOR as long as the injection is done pursuant to a Class II UIC. Any storage in an area not associated with EOR would be strictly prohibited. In the event that HECA decides to inject CO_2 for sequestration purposes only, whether on its own or by exporting it to a third party, HECA would have to file a petition to amend the project to allow it to do that.

Drilling Through CO_2 Areas

Conditions might arise that might require drilling a new well into or through a CO_2 injection zone, such as emerging better technology in the future that would enable extraction of crude oil from depleted oil formations or that crude oil prices might rise to levels that would justify increased cost of extraction from depleted oil reserves. Drilling through CO_2 areas could create a leakage pathway for the stored CO_2. This is especially important if enough time has not passed since the cessation of previous injection activities for the CO_2 plume to have dissipated enough that no significant amounts would leak through the new drilling. There are existing state and federal regulations that are intended to mitigate this risk. Several regulations and guidelines specifically address zonal isolation during well construction. These regulations and guidelines are designed to ensure that wellbores pose no significant risk of leakage of fluids, including CO_2, to the surface. For example, the production well permit issued by DOGGR has specific requirements for the construction of the wells in terms of cementing requirements to ensure that there is no cross contamination between zones and also that no contaminants will find their way to USDW. Further, the whole UIC program promulgated by the U.S. EPA is intended to protect USDW.

MONITORING, REPORTING AND VERIFICATION

Since the purpose of the EOR component from HECA's perspective is to result in the permanent storage of the CO_2 produced in excess of SB1368 limits, a robust monitoring, reporting and verification (MRV) plan is essential to give assurance that the injected CO_2 will remain stored, any potential future leaks, even after the plugging of injection wells will be detected and mitigated appropriately, and that the amounts of stored CO_2 are accounted for accurately. A good MRV plan should include the following elements at a minimum:

1- Thorough Site Characterization;

2- Monitoring and Remediation Plans for Potential Leaks;

3- Tracking of Injected CO_2 Plume;

4- Quantification of Sequestered CO_2 Volumes.

1. Site Characterization:

A good and thorough site characterization is essential for the understanding of the injection zones and the assessment of their potential for storing the injected CO_2. Site characterization should cover geologic setting, faults and fractures in the site, and logs of well bores that show the original stratigraphy of the wells and the final construction showing casings and cementing conditions. A thorough site characterization means the operator is aware of weak points in the system so that it can anticipate locations of future issues, which gives the operator a heads-up in isolating problematic areas.

OEHI conducted a three-dimensional (3-D) seismic survey over approximately 400 square kilometers (155 square miles) within the Elk Hills Unit (EHU) from 1999-2000. These 3-D data were computer processed to allow for an accurate interpretation of the EHU's complex structure. Information gleaned from this 3-D seismic program has been integrated with data acquired from drilling and well workover operations. This wealth of data has been used to complete a detailed structural and stratigraphic characterization of the reservoirs within the EHU. OEHI has used this information for years to develop and implement drilling, completion, and pumping innovations to manage the reservoir and maximize production throughout the field. This same information will enable OEHI to successfully meet the goals of the OEHI CO_2 EOR component.

A study of regional geology by Fiore et al showed two anticline structures (31S and NWS) that are part of the OEHI CO_2 EOR component and a third anticline structure (29R). The structures shown formed bathymetric highpoints on the deep inland marine surface (seafloor), affecting geometry and lithology of the contemporaneously deposited turbidite sands and muds generated as subaqueous turbidite flows. The study also showed the location and extent of four faults that helped to form these anticlines. Based on site-specific studies, OEHI has concluded that the vertical extent of three of the four faults, 1R, 2R and 3R, minimally penetrate the confining zone of the Reef Ridge Shale and do not present a likely pathway for leakage to the surface.

Analysis of OEHI's 3-D seismic data provides further evidence of the sealing characteristics of the Reef Ridge Shale. A 3-D seismic survey was performed from 1999 – 2000, and covered nearly 70 square miles in the EHU. The data were processed using pre-stack depth migration which produces superior imaging in steeply dipping beds, such as on the flanks of the Stevens structures. Analysis of these data indicates that faults above and below the Reef Ridge Shale terminate before penetrating the seal.

OEHI would inject CO_2 into the Stevens reservoirs on the 31S and NWS structures. The Stevens reservoirs of the Monterey Formation are considered the best CO_2 EOR targets within the EHOF. They have been developed on 10 - 20 acre pattern spacing and have produced over 500 million barrels of oil to date. Data collected from these operations have refined OEHI's understanding of the subsurface geology in the Stevens reservoirs. The Stevens reservoirs comprise both sandstone and shale lithologies.

Within the Main Body B (MBB) formation, fining-upward turbidite deposits known as Bouma Sequences stack to form lenticular sheet sands, channels, and levee deposits within a submarine fan complex (Reid, 1990). The sands have porosities between 20 and 25 percent, permeabilities that average 150 millidarcy, and net reservoir thickness that can exceed 1,000 feet. Pressure in the MBB is already near the minimum miscibility pressure (MMP), indicating that it is an ideal initial candidate for CO_2 EOR.

Overlying the Reef Ridge Shale above the 31S structure is the oil-producing shallow oil zone (SOZ). The SOZ is extensively layered with hydrocarbon containing sands and impermeable clay, forming many local traps. The SOZ itself is topped by a cap rock known as the San Joaquin Formation which is mainly comprised of continuous clay and shales interbedded with the lenticular Mya sands. There is extensive evidence supporting the vertical isolation between the Stevens reservoirs, and the SOZ and that the OEHI CO_2 EOR Project will not breach that isolation, including the following:

1- Distinct oil-water contacts, pressures, and temperatures of the Stevens and the overlying SOZ reservoirs indicate that there are no transmissive faults across the Reef Ridge Shale in the area of the OEHI CO_2 EOR component.

2- Employment of concurrent hydrocarbon development programs, some of which resulting in significant pressure changes, without causing interference in either the SOZ or Stevens reservoirs.

3- Volumes and pressures computed through reservoir simulation show that it would be nearly impossible to operate the OEHI CO_2 EOR component in a way that would compromise the seal. The capacity of the Stevens reservoirs is vast compared to the planned injection volumes, and the equipment that would be used to deliver HECA CO_2 physically limits the rate of injection below the injectivity of the Steven reservoirs, thereby not harming the integrity of the seal.

Furthermore, OEHI conducted a four-month pilot study in 2005 that produced data that provided additional confidence that the 31S structure is an attractive target for CO_2 EOR. The pilot study was designed to assess how much oil could be mobilized from the Stevens reservoirs, how much CO_2 would be required to mobilize that oil, and how quickly the oil would be mobilized. Information showed that the Stevens reservoirs selected for the OEHI CO_2 EOR component are ideal for EOR.

Beneath the Reef Ridge Shale is the NWS structure, which contains two reservoirs, A1 and A2. The NWS structure comprises stacked upper Miocene Stevens sands, which are the product of two coalescing turbidite channels. One channel contains the "T" turbidite medium to coarse-grained sands (thickness ~500 to 1000 feet), which form offlapping geometries and structural/stratigraphic traps due to deposition across the rising northwest-plunging nose of the NWS anticline. They contain an abundance of mudstone interbeds and are interpreted to represent a depositional channel fill which grades laterally to less permeable finer grained overbank deposits along the east side of NWS.

The second channel forms a 1700-foot sequence of 80 to 500-foot thick sandstone intervals having high net-to-gross ratios with abundant conglomeratic interbeds. These intervals have lenticular geometries at the top of the sequence and offlapping geometries at the base. The A1/A2 reservoirs on the NWS structure are currently at a very low reservoir pressure (<90 psig), having been pressure depleted during earlier operations. They will need to be re-pressurized to MMP before miscible EOR can begin and are able to accept CO_2 at lower pressure than will be required to inject CO_2 into the reservoirs in the 31S structure. The A1/A2 reservoirs within the NWS will be both an EOR target as well as an excellent source of “backup” storage capacity in the event of power outages, scheduled maintenance periods, or emergency shutdowns, or when injection into the MBB is not possible.

In addition to the characterization of the target storage reservoirs, OEHI also presented detailed information characterizing the properties of the sealing formation, the Reef Ridge (RR) Shale, which will act as the cap that will prevent leaks of injected CO_2. The information presented detailed the properties of the sealing formation in terms of physical rock characteristics of RR Shale, fluid contacts and reservoir pressure depletion, core analysis of the formation, seismic control, geochemical, and geomechanical analysis. The information provided indicate that the RR Shale would likely act as a competent seal to prevent the leakage of the injected CO_2.

Lastly, the areas above the RR Shale sealing formation were also covered in the 3-D simulation and field mapping and analysis provided by OEHI. These include the SOZ and non-productive area above the Stevens reservoirs in the NWS. Both of these areas would be used for monitoring of any potential, though unlikely, leaks that might occur through the sealing formation.

In light of the information provided by OEHI and briefly discussed above, describing the extensive characterization of the EHOF and the target injection zones as well as the seals that would prevent the injected carbon dioxide from escaping, staff believes that OEHI has adequately characterized the reservoir for the purpose of the sequestration activities.

2. Monitoring and Tracking of Injected CO_2:

Tracking the amounts of CO_2 that are injected as well as amounts leaked at the surface and those that occur during and after the injection process is essential for the determination of the net amounts that get sequestered. Another aspect of tracking the CO_2 is the tracking of the CO_2 plume in the ground to ensure that it would not migrate to sensitive areas where it could leak to the surface or to USDWs.

Tracking could be achieved using field measurements if there are enough wells that penetrate the formation which can be used to track CO_2 concentrations and pressures. Since the number of wells that penetrate the formation is typically not large enough to give enough details about the CO_2 plume, it is often necessary to use numerical modeling techniques to simulate the behavior of the CO_2 plume during and after injection. Quality of results of numerical models is dictated by how accurately the geophysical and geochemical properties of the formation parameters are represented in the numerical model. With the extensive characterization information about EHOF that OEHI is in possession, numerical modeling results should be quite representative.

OEHI proposes a monitoring program that includes simultaneous monitoring of:

- CO_2 injection and fluid production during operations of the OEHI CO_2 EOR component;
- A tiered approach to monitoring in the subsurface and at the surface to detect migration, if any, of injected CO_2; and,
- An approach to monitoring after CO_2 injection operations cease.

The previously mentioned centrally controlled monitoring network that OEHI has in place, which is referred to as the Central Control Facility (CCF) is used to make operational control decisions on a real-time basis throughout the EHOF to assure the safety of field operations and to comply with monitoring and reporting requirements in current permits. OEHI uses the CCF in its ongoing operations to collect flow, pressure, and gas composition data in a centralized data management system on a continuous basis 24 hours a day. OEHI has trained technicians who follow OEHI response and reporting protocols when the system delivers notifications if data exceed pre-determined statistically acceptable boundaries. The collected data can be accessed for immediate analysis. OEHI also will use the same CCF to collect and analyze data from the OEHI CO_2 EOR component.

OEHI intends to install and use custody transfer meters at points of custody transfer from HECA to the OEHI component and from OEHI to parties that purchase OEHI's products. The custody transfer meters would measure the fractions of the different gases that would be present in varying concentrations in the transferred products. The meters would be calibrated on a regular basis and by an independent party.

For injected CO_2, OEHI is required Under Class II UIC permits to report volumes of fluids injected. Following the manner in which injection volumes are reported under existing Class II UIC permits at the EHOF, OEHI would allocate aggregate injected volume from data collected at the meters going into the CO_2 facility (the custody-transfer meter and the two flow meters measuring recycled CO_2 from the production wells) to individual wells based on a ratio established by reviewing individual injection volume data as measured by in-field operations flow meters.

For CO_2 recovered with extracted fluids, OEHI is required under DOGGR regulations to report volumes of produced fluids (oil, water, and gas). Similar to the approach implemented under current DOGGR requirements for reporting produced fluid volumes, OEHI would be using two operations meters at each satellite gathering station to determine flow rates. One would be used to measure the aggregate volume of the produced fluid from all wells. The second meter would be used to measure the oil/water/gas rate of each production well on a rotating basis at least once a month. OEHI would use the total volume data gathered at each satellite gathering station and the results from each individual test of a production well to calculate total produced volumes from each production well.

For fugitive CO_2 amounts from surface equipment and venting processes, OEHI anticipates reporting those amounts pursuant to recently adopted federal regulations 40 CFR Part 98, Mandatory Reporting Rule for GHGs, and the analogous state provisions at Division 3, Chapter 1, Subchapter 10 of Title 17 of the California Code of Regulations, as applicable. Under the rules, OEHI would be required to report the total CO_2 and methane (CH4) emissions from the many source types, including those listed below, as they apply to the OEHI CO_2 EOR component:

- For onshore petroleum and natural-gas production: fugitive emissions from valves, connectors, open-ended lines, pressure-relief valves, compressor-starter gas vents, pumps, flanges, well work, and other fugitive sources (such as instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and breather caps for crude services);

- For onshore natural-gas processing: fugitive emissions from valves, connectors, open-ended lines, pressure-relief valves, meters, and centrifugal compressor dry seals; and
- For onshore natural-gas transmission: fugitive emissions from connectors, block valves, control valves, compressor blowdown valves, pressure-relief valves, orifice meters, other meters, regulators, and open-ended lines.

Monitoring to detect surface leakage of injected CO_2:

As discussed earlier, the only likely pathways for leakage of injected CO_2 to the ground surface are the well bores, both through the casing and production tubing and in the annular space between the casing and the formation. OEHI proposes to use a monitoring program that it designed to focus first on detecting unanticipated migration of the CO_2 out of the injection zone in the subsurface and, second, if such migration is detected, determining if leakage of CO_2 to the surface is occurring.

It is noteworthy that the OEHI CO_2 EOR activities would be conducted in an active and very productive oil field and is much like the existing waterflood project. Both the CO_2 injection and the water flooding are designed to enhance the recovery of existing oil that is left over from previous extraction processes using conventional methods. Although not currently a regulatory requirement, it is OEHI's current practice to monitor on a real-time basis the performance of producing oil reservoirs for differences between expected and observed performance and movement of fluids, a practice that OEHI plans to continue for the OEHI CO_2 EOR component. It is in OEHI's interest to keep accurate accounting of the amounts of fluids expected to be produced and those actually produced. Any difference in the two quantities tends to indicate inefficiencies in oil-production operations, and it is in OEHI's interest to address them quickly for improved performance. Typically, OEHI initially investigates wells or surface equipment to address such differences and it is standard practice to conduct further investigation of the subsurface if warranted. For the same reasons and to ensure the optimal use of purchased CO_2 during the CO_2 EOR component, OEHI would assess injection and production performance to identify and address anomalies that could identify opportunities to improve performance of the CO_2 EOR component or the possibility of leakage to the surface, even if not required to do so. OEHI would ensure that these procedures also meet all regulatory requirements and make any necessary modifications.

OEHI proposes to adopt a monitoring plan based on an iterative approach for both the monitoring and the resulting follow-up actions, if warranted. This monitoring plan includes four tiers. Tier 1 is monitoring in the injection zone to ensure operations are proceeding as expected. Tier 2 is the monitoring of the subsurface above the Reef Ridge Shale to ensure early detection in the unlikely event that injected CO_2 migrates through the Reef Ridge Shale. Tier 3 is the monitoring of well bores to ensure their integrity. Tier 4 is the monitoring of surface equipment and the areal surface over the injection zones to detect leakage at the surface. Before injection begins, OEHI would develop statistically reliable baselines for key parameters used in Tier 1 and Tier 2. Staff concludes that this is a reasonable approach to keep track of lost CO_2 amounts.

For detecting and dealing with leakage to the surface, Tiers 3 and 4 seem to be the most relevant. In Tier 3 OEHI proposes measures for the preparation of well bores using standards adopted by the American Petroleum Institute (API) as well as California regulatory requirements for well maintenance and monitoring. In addition, OEHI proposes to apply a corrosion protection program to establish and maintain a barrier between the steel used in wells and any CO_2-enriched fluids. Furthermore, OEHI plans to place a column of cement between the formation and the casing from total depth of the well bore from the bottom of the bore up to 500 feet above the shallowest open perforation of newly drilled wells to protect the well casing from corrosion and prevent injected CO_2 from leaking through the annular space. As an added measure, OEHI would also employ a cathodic protection system, which is already in place, to help in protecting steel well casings against corrosion by carbonic acid. If done properly, the cement column along with the cathodic system should be an effective way to prevent leakage and also to protect casings against corrosion.

In such a vast operation with hundreds of wells for injection and production, let alone the thousands of well bores that abound at the site for different purposes and at varying depths of penetration, leaks are prone to happen at some of the well bores. Tier 4 of the monitoring plan is for dealing with leaks when they are detected. OEHI's proposed procedure to deal with detected leaks involves immediate isolation of the leaking well, depressurizing the zone, and repairing the leaking well. While most likely the repair process would involve injecting a plug of cement to seal the place of the leak, the locations of these leaks are not always accessible to inject a plug of cement. In case the leaking spot in a well is not accessible for plugging, OEHI would have to abandon that well and drill another well.

Condition for Certification **GHG-5** is proposed by staff to account for lost amounts of injected CO_2, detection of leaks, and repairing leaks.

3. Tracking of Injected CO_2 Plume:

OEHI proposes to use a combination of modeling and best available data to demonstrate the magnitude and extent of the injected CO_2 within the Stevens reservoir. This will validate that the injected CO_2 is contained by the Reef Ridge Shale. Monitoring and full-field modeling conducted throughout the operational life of the project would be used to demonstrate that there continues to be no communication between the Stevens reservoirs and the areas above the Reef Ridge Shale and that the full volume of injected CO_2 is contained below the Reef Ridge Shale. Further, OEHI would use information regarding CO_2 in produced fluids from the 31S and NWS structures to demonstrate the reliability of the full-field simulation model in predicting movement of CO_2.

Furthermore, OEHI also proposes to use a combination of modeling and best available data to track the location of injected CO_2. OEHI would use measured data at the production wells to validate OEHI's full-field simulation model. After all injection and production operations in the Stevens reservoirs have ceased, movement of the injected fluids, including CO_2 would be driven by natural forces and would be countered by structural trapping (vertical movement mitigated by intervening shale layers and ultimately stopped at the physical boundary of the Reef Ridge Shale), capillary trapping and long-term mineralization processes.

OEHI has already used a full-field simulation model to predict the location and movement of CO_2 20 years from the start of injection as well as 118 years after closure. Model results showed that some of the injected CO_2 is projected to migrate to the top of the MBB within 20 years before it encounters the interbedded North American (NA) Shale within the Stevens reservoirs. Model results also showed that after 118 years after injection has stopped the concentration of CO_2 at mid-depth would be lower than it was after 20 years, showing some movement away from the injection point. However, predicted concentrations at the top of the MBB showed that the main movement of the injected CO_2 would be in the vertical direction since it was shown that there would be more areas with a higher concentration of CO_2 towards the top of MBB than is predicted after 20 years. CO_2 plume vertical movement was shown by the model to be slowed or trapped by the interbedded NA Shale. This gives further evidence that staff finds to be assuring that the target zone for storage would remain isolated and no substantial movement of the injected plume would occur.

4. Quantification of Sequestered CO_2 Volumes:

OEHI would apply mass balance principles to determine the amounts of CO_2 that would get sequestered as a result of the EOR operation. The amount of CO2 sequestered is simply the difference between the amounts received and the amounts of losses, as in the following equation:

$$C_s = C_t - C_p - C_l - C_{fv}$$

where C_s is sequestered CO_2, C_t is total CO_2 received from HECA, C_p is CO_2 measured at the custody-transfer points in products sold offsite, C_l is CO_2 emitted through leakage, and C_{fv} is fugitive and vented CO_2 associated with injection and production.

All the quantities in the mass balance equation can be readily determined, except for the amount associated with leakage. To estimate this amount, both flow rate (either volumetric or mass) and concentration of CO_2 involved will have to be known. Because the amount of CO_2 leaked to the surface will depend on the nature of the equipment and an estimation of the duration and concentration of the leak, OEHI says that it would not be able to predict in advance the approach that would be appropriate to use to determine the amount until after the leakage has been detected. Staff finds this to be an anomaly. After the leak has been detected it would be too late to determine how much has leaked as some of the CO_2 has already escaped. OEHI should find a way to be able to assess the volumes of fugitive gases in advance of the detection of leaks. Staff believes that such a setup might be simply a tent over the well head which would be instrumented to measure volumes of fugitive gases right after a leak has been detected. Since it would take some time for the fugitive gas to travel from the location of the leak to the ground surface, the system operator would have an early warning to activate the system in the tent to be ready to capture those fugitive gases.

Since OEHI has not provided detailed information on the approach it would apply to assess the amounts of CO_2 leaked to the surface, staff cannot assess the effectiveness of the approach. OEHI should decide on one or more approaches to be used for assessing the amounts of fugitive CO_2 ahead of the detection of leaks and provide details of those approaches to staff for assessment.

Staff has recommended conditions of certification that would require the facility owner or operator to ensure effective CO_2 sequestration, monitor for and fix CO_2 leaks, and mitigate the potential for geologic/seismic impacts from the EOR project. If after completion of the proposed CO_2 injection project all wells are plugged and abandoned in accordance with the requirements of Class VI UIC, downwind monitoring of CO_2 concentrations at a few strategic points would be sufficient. If some or all of the wells are not plugged and abandoned, periodic monitoring of casing pressures, as well as surface monitoring of CO_2 concentration would be necessary. Additionally, according to the Class VI regulations, the Area of Review (AoR) associated with Class VI wells is required to be revised continually until site closure. Revision of the AOR requires continuous modeling of the CO_2 plume through the post injection period until site closure.

Closure and Decommissioning

After HECA shuts down, there exist different paths forward for the OEHI CO_2 EOR component. For example, (1) all wells are plugged and abandoned and a CO_2 emission monitoring program is continued for many decades; (2) some or most of the CO_2 injected into the proposed project is produced and re-injected into the adjacent reservoirs, or (3) CO_2 from another source is obtained and is injected into a project expansion. Regardless of what option is chosen, eventually the wells would need to be closed and decommissioned in a manner that retains the sequestered CO_2.

The U.S. EPA issued regulations specifically designed for plugging and post plugging site care for injection wells used for long term storage of CO_2 that are found at 40 CFR part 146 subpart H. In order to ensure that plugging and PISC are done properly, staff recommends that the applicant comply with U.S. EPA's requirements for well plugging and PISC through compliance with Condition of Certification **GHG-3**. Specific requirements of the U.S. EPA Class VI rule for plugging and PISC are summarized in **Carbon Sequestration and Greenhouse Gas Emissions Table 13**. In addition to requirements that the plugging be done following standard plugging procedures, the rule also requires that the injector should allow a representative from an agency with jurisdiction to witness the plugging procedure. Also, Class VI rule requires specific monitoring of plugged wells during the period from well plugging until the closure of the site, referred to as PISC, which include the preparation of a corrective action plan to deal with potential leaks from plugged wells and demonstration of financial preparedness to cover the expenses to implement the corrective action plan.

Cumulative Impact

Cumulative impacts are defined as “two or more individual effects which, when considered together, are considerable or . . . compound or increase other environmental impacts” (CEQA Guidelines § 15355). “A cumulative impact consists of an impact that is created as a result of a combination of the project evaluated in the EIR together with other projects causing related impacts” (CEQA Guidelines § 15130[a][1]). Such impacts may be relatively minor and incremental, yet still be significant because of the existing environmental background, particularly when one considers other closely related past, present, and reasonably foreseeable future projects.

There are no other projects in the vicinity that currently engage or will engage in the foreseeable future in injecting CO_2 for EOR or sequestration purposes. Therefore, the OEHI EOR CO_2 component would not be expected to cause any cumulative environmental impacts either by itself or in combination with other projects.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

A number of public comments have been received regarding GHG emissions/climate change and carbon sequestration.

RESPONSE TO GHG EMISSIONS/CLIMATE CHANGE COMMENTS

The table below contains staff’s responses to comments received pertinent to GHG emissions/climate change topics addressed in this section submitted by government agencies, intervenors, and the public. This comment response includes responses to comments provided to the Energy Commission and to the DOE.

Submitted by:	*COMMENT and RESPONSE*
AGENCY: U.S. Environmental Protection Agency (U.S. EPA)	
Agency – U.S. EPA (TN-66381) 7/26/2012	Comment: (summarized) The DEIS should include an estimate of the quantities of greenhouse gases both generated and sequestered by the project, and a discussion of the indirect impacts from the extended oil production that will occur at the Elk Hills Unit because of the project. We suggest including a graphical illustration showing the mass balance of carbon for clarity and comparison of alternatives. Response: This section does provide estimates of the quantities of the emissions generated by HECA and by the OEHI CO_2 EOR component. These estimates include traffic and secondary electricity consumption. Additionally, to better describe the EOR component the range of potential petroleum production is provided. However, the GHG emissions from the EOR component’s produced oil use are not considered to be relevant in the discussion of the project’s impacts. With or without EOR necessary oil

	production to meet petroleum product demand will occur, at the Elk Hills site using other means, domestically, or overseas. It can also be argued that production closer to demand, similar to the greenhouse reduction concept of using local products, actually reduces overall GHG emissions by reducing transportation emissions.
Agency – U.S. EPA (TN-66381) 7/26/2012	Comment: (summarized) The following are suggested for inclusion in the greenhouse gases/climate change discussion: • General climate change causes and effects. • Project sector contribution to GHG emissions. • Description of applicable GHG LORS • Discussion of the Energy Policy Act of 2005 and EO 13423. • Identification of local and regional climate change initiatives. • GHG emissions inventory. • Context of emissions by EPA's GHG equivalency calculator. • GHG emission reduction measures discussion. • Project impacts on CO_2 sinks and land albedo. Response: This section has attempted to include discussions related to all of the above U.S. EPA identified GHG/climate change topics that are relevant to this project. Comparing the project's emissions to equivalent passenger vehicles or other units provided by the EPA's GHG equivalency calculator is not considered directly relevant to the impact assessment of a power plant project. EO 13423 is not relevant and does not apply to this project. That executive order applies to the internal operation of federal agencies. While Hydrogen Energy International, LLC will be obtaining funds from a federal agency it is not itself a federal agency nor is agency funding of this type covered under EO 13423. Also, the relevance of the Energy Policy Act of 2005 is not clear. Parts of that Act may be relevant in terms of the project description discussion; however, we need further clarification regarding what parts of this act EPA considers specifically relevant to the greenhouse gases/climate change discussion for this project.
Agency – U.S. EPA (TN-66381) 7/26/2012	Comment: Impacts of climate change on the project. The DEIS should identify how the project could be affected by climate change. This could include changes to water availability, temperature increases, increased extreme weather events (flooding, etc.). Adaptation strategies should be identified and discussed, as appropriate. Response: Water availability issues are discussed in the Water Resources Section. Staff believes that the project will be appropriately designed for extreme

	weather events and given the project type, location, and the expected project life, no climate change adaptation strategies are necessary for this project.
Agency – U.S. EPA (TN-66381) 7/26/2012	Comment: Cumulative climate change impacts on resources also affected by the project. The DEIS should also include a discussion on cumulative climate change impacts to resources also affected by the project. If there are project impacts on environmental justice (EJ) communities, the cumulative impacts from climate change on public health and environmental justice communities should be discussed. Response: Staff does not believe that the project will have measurable localized climate change impacts, such as impacts from climate change on public health or environmental justice communities. Staff has preliminarily concluded that the project would reduce GHG emissions as a whole when considering the electricity sector within the WECC and the balance of the project's fertilizer manufacture and EOR component's oil production, and therefore create a beneficial climate change impact. Additionally, staff has concluded that the project would also demonstrate both CO_2 emissions reduction for coal power plants and also demonstrate plant design flexibility, with the inclusion of the fertilizer manufacturing plant that increases the plant's energy dispatchability, which is desirable as non-dispatchable renewable energy's role increases over time.
INTERVENOR: Association of Irritated Residents (AIR)	
Intervenor – AIR (TN-66342) 7/27/2012	Comment: (summarized) Total pollution and GHG emissions must be analyzed from cradle to grave for this project. Response: This section includes a GHG emission estimate for construction emissions and operation emissions for both HECA and the associated OEHI CO_2 EOR component that includes all project related stationary sources, mobile sources, and area sources including the fuel feedstock (i.e. coal) transportation emissions that occur from the mine to the project site.
Intervenor – AIR (TN-66342) 7/27/2012	Comment: (paraphrased) Electricity used in the EOR process uses an inappropriate baseline for GHG emissions, which should be the state average emission rate. Response: Staff agrees with this comment, and determined that the current WECC California emissions factors values recommended for use by The Climate Registry (658.68 lbs CO_2/MWh and 661.2 lbs CO2E/MWh) provides a better emission factor for the indirect electricity GHG emissions factor for this new base load electricity consumption source, and staff revised the GHG emission estimates for the OEHI CO_2 EOR component shown in the emissions tables using these values.

INTERVENOR: Sierra Club	
Intervenor – Sierra Club (TN-66370) 7/27/2012	Comment: (summarized) NEPA requires governmental agencies to consider impacts on the global environment including global climate change, as well as local and regional impacts. Response: The DOE has determined that this section adequately addresses global climate change per NEPA requirements.
Intervenor – Sierra Club (TN-66370) 7/27/2012	Comment: (summarized) Action to reduce emissions is warranted as the EPA states that GHGs endanger the public health and welfare of the current and future generations. Response: This project includes the geologic sequestration of CO_2 emissions from coal/coke derived power generation. This emissions reduction technology would cause a significant reduction in emissions from high-carbon content fuel use.
Intervenor – Sierra Club (TN-66370) 7/27/2012	Comment: (summarized) DOE should consider total CO_2 emissions from the project including transportation emissions and EOR component emissions including oil recovery. Response: The direct and indirect GHG emissions, including transportation emissions, from both HECA and the OEHI CO_2 EOR component have been considered and tabulated in this analysis.
Intervenor – Sierra Club (TN-66370) 7/27/2012	Comment: (summarized) Even with sequestration, HECA is a large source of GHG emissions with almost a half million tons of CO_2 per year from stationary source alone. DOE must consider how the lifecycle GHG emissions compare on a megawatt basis to a natural gas plant, and other renewable energy alternatives. Response: This section provides a comparison of the emissions of this project and other fossil fuel alternatives, including natural gas combined-cycle projects. We are not aware of an acceptable reference source that provides comparable lifecycle emission estimates for other fossil fuel alternatives, nor are lifecycle emissions estimates available for HECA. However, we have provided emissions estimates and noted what is included in each estimate to identify where the comparisons are not equivalent. This project would clearly emit more CO_2 than most renewable energy facilities, whether or not lifecycle emissions are considered. However, low CO_2 emitting renewable energy sources (solar, wind) cannot be used for base load power generation, and higher CO_2 emitting renewable energy sources (waste-to-energy, geothermal) cannot generally provide any

	dispatchable power, so these type of resources do not meet the same project goals and objectives as HECA and so are not comparable technologies/projects.
Intervenor – Sierra Club (TN-66370) 7/27/2012	Comment: (summarized) Since the CO_2 is being used to extract more oil from the ground that will be combusted to produce more CO_2 emissions, DOE must analyze the lifecycle of the oil combustion including transport of the crude oil produced in the field, crude oil refining, and the combustion of the refined petroleum products. Response: The GHG emissions from the EOR component's produced oil use are not considered to be relevant in the discussion of HECA's impacts. With or without this project, necessary oil production to meet petroleum product demand will occur, at the Elk Hills site using other means, or otherwise at other North American or overseas sources. It can also be argued that oil production that occurs closer to demand, similar to the greenhouse reduction concept of using local products, actually reduces overall GHG emissions.
Intervenor – Sierra Club (TN-66370) 7/27/2012	Comment: (summarized) The EIS should examine alternatives and mitigation measures designed to eliminate or minimize CO_2 equivalent emissions. Response: This section includes the evaluation of the geologic sequestration of CO_2 emissions which is considered the project's primary GHG emissions mitigation measure. The project also provides for alternative use of the project's fuel source that would allow the project to be partially dispatchable which would also reduce emissions from electricity generation; through the reduction of the use of higher GHG emitting dispatchable resources such as simple cycle peaking gas turbines. Additionally, the District's GHG BACT determination considered applicable and appropriate technology alternatives and found that the project's design met GHG BACT requirements. Please also see the Alternatives section for additional project alternatives discussion.
Intervenor – Sierra Club (TN-66370) 7/27/2012	Comment: (summarized) DOE should assess the impacts of global warming on different environmental receptors in Kern County. The EIS should analyze the local, regional, global environmental impacts of CO2E emissions from the HECA facility, focusing to the impact of global warming on California's and Kern County's water resources and existing air quality problems. Response: This section does describe the potential regional impacts of climate

	change. However, HECA would be globally and regionally a very small contributor to overall GHG emissions, and unlike criteria pollutant emissions, would not by itself create any localized global climate change impacts. The DOE also believes that demonstrating the feasibility of large scale GHG emission reduction technologies, such as the carbon separation and sequestration technology that is proposed to be employed by HECA, will foster greater change in current power generation technologies and help contribute to future globally significant reductions of GHG emissions from coal power plants, both within and outside of the United States.
PUBLIC COMMENTS	
Public – Arthur Unger (TN-66357) 7/26/2012	Comment: (summarized) How much GHG will the cars, trucks and trains that bring employees, fuel, equipment and waste to and from the plant during construction and operation make? Response: The GHG emissions from the sources noted in this comment are included in **Carbon Sequestration and Greenhouse Gas Emissions Tables 3** and **4**.
Public – Arthur Unger (TN-66357) 7/26/2012	Comment: (summarized) How much GHG will the oil recovered in the course of the HECA project emit? Response: The air pollutant and GHG emissions from the EOR component's produced oil use are not considered to be relevant in the discussion of the projects' impacts. With or without this project, necessary oil production to meet petroleum product demand will occur, at the Elk Hills site using other means, domestically, or overseas. It can also be argued that production closer to demand, similar to the greenhouse reduction concept of using local products, actually reduces overall GHG emissions.
Public – Trudy Douglass, et. al. (TN-66389) 7/30/2012	Comment: (summarized) In return for HECA taking our air, land, water and peace of mind, we receive a rise in GHGs because of inadequate diligence in the carbon sequestration process. Response: Staff has concluded that this project would not cause a rise in GHG emissions from the electricity sector, and staff has provided Conditions of Certification **GHG-1** through **GHG-5** that would provide adequate monitoring and verification to assure that the proposed carbon sequestration would provide the GHG emission reductions necessary to reduce GHG emissions overall from electricity generation.

RESPONSE TO CARBON SEQUESTRATION COMMENTS

The table below contains staff's responses to comments received pertinent to carbon sequestration topics addressed in this section submitted by government agencies, intervenors, and the public. This comment response includes responses to comments provided to the Energy Commission and to the DOE.

Submitted by:	*COMMENT and RESPONSE*
AGENCY: U.S. Environmental Protection Agency (U.S. EPA)	
Agency – U.S. EPA (TN-66381) 7/26/2012	Comment: (summarized) The DEIS should evaluate the increased risk of seismic activity resulting from proposed CO_2 injection. Response: This section provides an evaluation of the potential increased risk of CO_2 injection induced seismic activity. Long-term gas injection works entail a risk of induced seismic activity. However, most of the seismic events will be too weak to be felt by people. There might be some stronger events, 3-3.5 on the Richter scale. Given that Elk Hills is in a seismically active area, these minor injections and production related tremors will be negligible.
INTERVENOR: Sierra Club	
Intervenor – Sierra Club (TN-66370) 7/27/2012	Comment: (summarized) The EIS must consider whether the CO_2 emissions will indeed be permanently sequestered underground pursuant to enforceable permits. Currently, it is unclear which agency and which permits will ensure that carbon emissions from the facility are not ultimately emitted into the atmosphere. Response: The Energy Commission is taking control of the enforcement of the geologic carbon sequestration through proposed Conditions of Certification **GHG-1** through **GHG-5** and will retain control of assuring carbon sequestration throughout the project life and beyond. Additionally, ARB is responsible for drafting the regulations that will cover the monitoring method requirements and enforceability of geologic carbon sequestration, and depending on the pending legislation, either they or DOGGR may also be responsible for ongoing enforcement and assurance of geologic carbon sequestration under the Cap and Trade regulations.
Intervenor – Sierra Club (TN-66370) 7/27/2012	Comment: (summarized) DOE must consider the potential impacts of sequestering 3 million tons of CO_2 per year and analyze the potential for surface leaks, induced seismic activity from injecting the large amount of carbon underground and groundwater contamination. Response: This section includes an analysis of the geologic feasibility and

	implications of the OEHI CO_2 EOR component including the potential for induced seismicity. Staff's proposed conditions of certification, particularly **GHG-3**, are designed to monitor and control CO_2 leakage, both short and long-term, to assure permanent carbon sequestration.
Intervenor – Sierra Club (TN-66370) 7/27/2012	Comment: (summarized) DOE must ensure that Elk Hills has adequate financial mechanisms in place for long-term stewardship of the Elk Hills site. Response: Staff's proposed condition of certification **GHG-3** is designed to ensure that there is a financial instrument in place to assure long-term stewardship of the Elk Hills site that will ensure permanent carbon sequestration.
PUBLIC COMMENTS	
Public – Trudy Douglass (TN-66245) 7/12/2012	Comment: (summarized) Our site is farm land, at the closed end of a valley, with porous shale to hold the CO_2 until holes are drilled through our protective barrier for oil recovery. The CO_2 will make our air quality worse. Response: It is extremely unlikely that the injected CO_2 will ever flow through the natural geological barriers, especially given the large number of alternating layers of sand and shale present at the site, which is a very favorable arrangement of geologic features for sequestration of the CO_2. CO_2 is a colorless and odorless gas that will be monitored at the surface for potential, but unlikely, leaks along the wellbore casings, and leaks in the surface piping. Staff's proposed conditions of certification, particularly **GHG-3**, are designed to monitor and control CO_2 leakage, both short and long-term, to assure permanent carbon sequestration. The carbon dioxide will not make local air quality worse.
Public – Daniel Bell (TN-66248) 7/16/2012	Comment: (summarized) What is the estimated space currently available in the Elk Hills? What data is the 3 million tons of CO_2 per year based on? Is this based on start-up quantities or lifetime estimates? Response: The annual CO_2 injection rate of 3 million tons is based on the amount of CO_2 that would be separated and transported from the HECA site to the OEHI CO_2 EOR site assuming the permitted maximum annual operation at HECA. In terms of reservoir management, it is the volume of injected fluids, not mass, that counts. The project would have a net volume requirement of 1.1 billion reservoir barrels of CO_2 and water injection over the project's life. So, that needs to be compared with the available reservoir pore volume. Assuming 160 patterns × 20 acres/pattern × 43,560 square feet/acre × 1000 feet depth of formation × 0.225 (pore space fraction)/5.615 cubic feet/barrel = 5.6 billion barrels. Scaling this number with Occidental Petroleum's production estimate, (5.6 billion barrels /7.5

	billion barrels within the reservoir × 1.3 billion barrels net fluid volume produced from the reservoir = 1 billion reservoir barrels of fluid will have been produced from the proposed project area. This number representing the currently available pore space is somewhat less than the net 1.1 billion reservoir barrels of CO_2 and water injection required by the project, but the amount of additional oil and water that will be produced during the project will more than compensate for the difference. Therefore, there is ample pore volume into which the CO_2 and water will be injected. The total CO_2 volume to be injected over the lifetime of the project is expected to occupy only about five percent of the total pore volume of the reservoir.
Public – Dean Clason (TN-66349) 7/26/2012	<u>Comment:</u> (summarized) The concept of "trapping" CO_2 in ground formation is unproven and the local leaks from high pressure injection wells that were supposed to trap drilling fluids instead wound up polluting the local aquifer resulting in the City of Bakersfield having to abandon local wells. <u>Response</u>: Physical CO_2 trapping, which is a slow accumulation of free CO_2 in the reservoir pore volume, is a real, relatively short term process resulting in the retention of 5-30 percent of the injected CO_2 per pass. Trapping has been observed to occur even in situations where it is undesirable to be trapped, such as enhanced oil recovery where recovery of injected CO_2 is desirable so that it can be used in subsequent injections to minimize CO_2 purchases. The injection zone is known to have stored oil and gas under pressure for millions of years, and that's why it is believed to be capable of holding the injected CO_2. A strict monitoring plan, as outlined in Condition of Certification **GHG-3**, will be required to monitor any potential, albeit unlikely, leakage of the injected CO_2 at the surface along the wellbore casings; and to monitoring the leakage from the above ground piping components, which are the most likely, albeit low volume, leak outlets for any potential CO_2 emissions leaks to atmosphere. The CO_2 that is trapped in the Stevens reservoir cannot penetrate the geological barriers at the EOR site. The Stevens reservoir is located below a thick shale layer that itself underlies several additional alternating layers of shale and sandstone that provide an impermeable barrier. Therefore, there is little or no potential for groundwater contamination except through the well bores. The wells will have to meet UIC regulation requirements that are designed to protect groundwater.
Public – Kathleen Parsa (TN-66385) 7/23/2012	<u>Comment:</u> (summarized) Burying 2.5 million tons of CO_2 a year may pose a higher risk of seismic activity. <u>Response</u>: It is not the amount of CO_2 purchased that matters, but the duration of the injection process and changes of stresses in the reservoir because of the changing pore pressure. California is a place with a high risk of seismic activity, but the additional potential risks from CO_2 injection and fluid withdrawal for the OEHI CO_2 EOR component have been determined to be negligible.

Public – Trudy Douglass, et. al. (TN-66389) 7/27/2012	Comment: (summarized) The CO_2 to be sequestered is going into oil shale and the sandstone barrier expected to hold it has been drilled for oil exploration for more than 100 years. Response: Approximately 1,231 wells penetrate the Stevens reservoir. Currently 1,021 active wells penetrate the Reef Ridge Shale in the 31S structure; 128 wells are permitted by DOGGR as UIC Class II injection wells and 749 wells are permitted by DOGGR as production wells. In addition, there are 144 wells that can be both producers and injectors at the completion level within different reservoirs, or have been “plugged and abandoned” in one reservoir, but are active in another, or have changed well type. There are 178 inactive injection and production wells, 22 injection and production wells that have been “plugged and abandoned” according to regulatory requirements, and 10 wells that are shut in. The risk of CO_2 leakage from the Stevens reservoir through the wells drilled down through the Stevens reservoir will have to be monitored for decades. Staff’s recommended Conditions of Certification, particularly **GHG-3**, address these well field monitoring requirements.
Public – Trudy Douglass, et. al. (TN-66389) 7/27/2012	Comment: (summarized) The defined purpose of sequestration is the permanent removal of greenhouse gases. SCS’s proposal gives millions of tons of CO_2 to Occidental Petroleum to use without restrictions. This proposal does not meet DOE guidelines for the permanent removal of GHGs. Response: The Energy Commission is responsible for the enforcement of the geologic carbon sequestration through proposed Conditions of Certification **GHG-1** through **GHG-5**, which are designed to assure permanent carbon sequestration. Staff will require SCS to pass along these requirements to the well field operator via contract, and provide that contract prior to completion of the FSA/FEIS.
Public – Trudy Douglass, et. al. (TN-66389) 7/27/2012	Comment: (summarized) If all of HECA’s gasification, storage, sequestration, and transfer processes work perfectly, they will add only 520 tons of pollution and particulates a year to Kern County air. This does not include the millions of tons of CO_2 it is supposed to permanently sequester. Response: Please see the response provided above, and the comment responses in the Air Quality section.
Public – Trudy Douglass, et. al. (TN-66389) 7/27/2012	Comment: (summarized and edited) The process of sequestration is unclear. An added problem for the HECA project factory is that we aren’t even being given a valid form of sequestration. SCS said the CO_2 will crystallize but, how long will that take? Will the gas be in the ground long enough for it to happen or just come right up though the perforated sandstone?

	Response: The CO_2 cannot penetrate the geological barriers at the EOR project site. The Stevens reservoir is located below a thick shale layer that itself underlies several additional alternating layers of shale and sandstone that provide an impermeable barrier. The only expected possible escape pathways will be through the wells, but these wells will be required to be cemented in and sealed ("plugged & abandoned") after they have completed their active life, and then monitored for CO_2 leaks. Requirements for monitoring active and abandoned wells are included in staff's proposed conditions of certification. Chemical CO_2 trapping by mineralization is a mechanism that operates on a time scale of decades and centuries. It is rather irrelevant when a 20-year time scale is considered. Physical CO_2 trapping, which is a slow accumulation of free CO_2 in the reservoir pore volume, is a real relatively short term process resulting in the retention of 5-30 percent of the injected CO_2 per pass. While there will eventually be mineralization of the CO_2 that is physically trapped in the formation, that process is not required to occur in order to ensure long-term CO_2 sequestration in the formation.
Public – Trudy Douglass (TN-66427) 7/27/2012	Comment: (summarized) The Tupman facility will not even sequester the CO_2. HECA will turn it over to Occidental Petroleum to play with. Response: Staff's is requiring that there is a contract in place between HECA and OEHI that ensures that the CO_2 ownership issue does not impact the assurance of carbon sequestration prior to publication of the FSA/FEIS.
Public – Cindy Stiles (TN-66497) 8/3/2012	Comment: (summarized) Sequestering large volumes of CO_2 may very well stimulate seismic activity and this plant is very near to the San Andreas Fault as well as the California Aqueduct, the water lifeline for much of Southern California. Response: As was noted above, the seismic impacts of CO_2 injection into a sandstone reservoir will be infinitesimal compared with the already existing strong seismic activity. Therefore, the proposed project would not result in any impacts to the California Aqueduct.

CONCLUSIONS

Staff analyzed the proposed carbon sequestration plans for impacts to the environment in terms of geologic impacts and impacts to USDWs. Staff concludes that the proposed injection site conditions are favorable to inject the projected amount of CO_2 over 20 years. Given geologic lifetimes of natural CO_2 domes, and many long-lasting CO_2 injection projects, staff believes that it is likely that the injected CO_2 would be stored permanently in the Elk Hills Oil Field.

The conclusion above is supported by the fact that the formations where the CO_2 would be stored are separated from the surface by 5,000 to 7,000 vertical feet of other formations, including thick and continuous shale layers. In order to ensure that the injected CO_2 would remain sequestered, staff recommends that the project wells be plugged and abandoned in accordance with the plugging requirements for wells intended for long term storage of CO_2, as specified in Condition of Certification **GHG-3**. The injected CO_2 might possibly leak through the geologic formation and the well bores. The presence of the several thick and continuous shale layers above the injection zones makes it very unlikely, if at all possible, for the CO_2 to leak through the formation. However, since there are a large number of well bores at the project site, both active and abandoned, the potential for leaks through those well bores could be quite significant. OEHI stated that it already has in place a sophisticated monitoring system to detect gases that come out through active well bores, which would be utilized to detect potential CO_2 leaks. In addition to the monitoring network at active wells, staff recommends that the monitoring network should be extended to include plugged and abandoned wells. The CO_2 monitoring program must be maintained throughout the project life and also for the period between plugging of the wells and the site closure in accordance with the requirements for well plugging and PISC as specified in Condition of Certification **GHG-3**.

In the unlikely event of a major leak due to a well-control incident, leak-specific measures would have to be undertaken, including but not limited to, depressurizing the reservoir, isolation of the offending well, and the drilling of a relief well that would intercept and quell the leaking well if necessary. In light of the information available for the proposed sequestration field, staff believes the likelihood of such an event is very low.

As long as CO_2 sequestered in the oil field remains under ground, HECA would emit considerably less GHG than existing coal-fired power plants, but would have GHG emissions efficiency that is somewhat worse than current natural gas fired combined cycle plants. The proposed project would be subject to the state's cap and trade regulation that will enforce sector wide GHG emission reductions to meet state planning goals. While the proposed project's operation may not result in a cumulative overall reduction in GHG emissions from in-state power generation and out-of-state imported power, like a cogeneration facility it would have additional benefits to consider, namely the production of 1 million tons of nitrogen-based fertilizers and the production of crude oil and natural gas. Considering the entirety of the project, staff has preliminarily determined that the project would not result in an overall increase in global GHG emissions, and would thus not result in CEQA impacts that are cumulatively significant.

Staff concludes that the GHG emission increases typical from construction and decommissioning activities would not be significant for several reasons. First, the periods of construction and decommissioning would be short-term and not ongoing during the life of the proposed project. Second, the best practices control measures that staff recommends, such as limiting idling times and requiring, as appropriate, equipment that meets the latest emissions standards, would further minimize greenhouse gas emissions since the use of newer equipment would increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of the ARB regulations to reduce GHG from construction vehicles and equipment. Finally, the construction and decommissioning emissions are miniscule when compared to the reduction in fossil-fuel power plant greenhouse gas emissions during operation. For all these reasons, staff concludes that the short-term emission of greenhouse gases during construction would be sufficiently reduced and would be offset during proposed project operations and, therefore, would be less than significant.

HECA would be subject to EPS since it would operate more than 60 percent of capacity and since for economic viability it would need to obtain a base load energy contract with an investor owned utility (IOU) or a publicly owned utility (POU). HECA, with an appropriate binding contract with OEHI and appropriate conditions of certification, would likely meet the requirements of SB 1368. However, to finalize this finding, staff needs the applicant to provide a comprehensive MWh energy balance for the HECA facility, including the air separation unit, that shows all of the energy production and use at the HECA site. Staff is requiring that the binding contract between HECA and OEHI regarding CO_2 use, sequestration CO_2 emission reduction use, and CO_2 sequestration monitoring and recordkeeping requirements be provided prior to publication of the FSA/FEIS. Additionally, HECA would comply with GHG PSD requirements, as determined by the District's PDOC, and would comply with the state's cap and trade regulations.

OUTSTANDING INFORMATION REQUIRED FOR COMPLETION OF THE FSA/FEIS

Staff requires the following information to complete the FSA/FEIS:

1. A binding contract between SCS Energy LLC and Occidental of Elk Hills, Inc., provided to the Energy Commission that:
    a) Identifies the responsibilities of each party to demonstrate and document permanent sequestration of the supplied carbon dioxide.
    b) Documents Hydrogen Energy California's rights to the entire carbon dioxide sequestration emissions reductions as necessary for SB 1368 EPS and other regulatory compliance.
    c) Clearly states that the carbon dioxide sequestration emissions reductions shall not be used for any other purpose than providing for the compliance obligation needs for HECA.
    d) This contract shall also require Occidental of Elk Hills, Inc. to provide a Carbon Dioxide Emissions Sequestration Plan to the Energy Commission for review and approval as detailed under the preliminary staff Condition of Certification **GHG-3**.
    e) Clearly states the duration of the contract agreement.

2. A complete electrical energy balance estimate for HECA that includes the complete gross electrical production and complete parasitic load for the plant by major functional area, including the air separation unit, in MWh for both hydrogen rich fuel and natural gas operation. Staff cannot complete its determination of compliance with the SB 1368 EPS without this information.

3. A revised greenhouse gases emissions estimate for HECA that matches the current project description, including but not necessarily limited to: the removal of the ammonia product shipping emissions; the addition of the limestone fluxant shipping and use; and that addresses the shipping emissions for potential alternative shipping locations for the gasifier solids.

4. The District's FDOC that addresses staff's comments on the PDOC, specifically revising the combined-cycle power generating permit unit condition 86 to be based on the District's CO_2 BACT determination rather than the SB 1368 EPS.

5. Further information describing how OEHI would abate CO_2 if it leaks to the surface and escapes into the atmosphere.

6. Please provide information detailing how the applicant would comply with the proposed allowable CO_2 venting hours without a back-up CO_2 injection zone.

7. Please provide all of the following:

   BACKGROUND
   Since the Amended AFC was filed there have been a number of changes to project design including a change to the power output of the combustion turbine, the addition of fluxant to the gasification process and the discontinuation of exporting ammonia as a stand-alone product. In addition, the applicant presented revised SB 1368 emission calculations in an e-mail sent to staff on May 10, 2013. Therefore Energy Commission staff needs additional information to revise air quality and greenhouse gas (GHG) emissions for consistency with the assumptions and data provided in these new calculations and to account for all revisions to the project design and operation assumptions that have occurred since the Amended AFC was submitted. The following information is still needed to complete the analysis for the Final Staff Analysis/Final Environmental Impact Report. Some of the terms below such as "Power", Fertilizer" and "Common" refer to computations in the new material presented in spreadsheets provided by e-mail on May 10, 2013.

   A. Please provide a carbon balance for HECA demonstrating the complete flow of carbon from the introduction of feedstock to the coal dryer to the products (including carbon dioxide [CO_2]) and waste streams. Please provide this carbon balance for both the On- and Off-Peak operating cases. This carbon balance should be more detailed than what was previously provided in the Amended AFC and data responses, clearly identifying the carbon in all the streams between major processes and process units where carbon flows change.

B. Please provide detailed background information supporting the latest applicant- sponsored SB 1368 calculations. Please provide the following:

- A detailed list of the project equipment indicating each piece of equipment's power consumption value; and
- Project equipment allocation (Power, Fertilizer or Common) for each listed piece of project equipment.

C. Please provide the gross and net megawatt (MW) assumptions for the three available ambient cases (39, 65 and 97 degrees F). Include the On-Peak, Off-Peak and Daily Average categories.

D. Please describe how the fertilizer power generation values, which appear to be different than the previously presented 5 MW value, were determined for the On-Peak and Off-Peak Cases.

E. Please provide detailed calculations and rationale for the Syngas Allocation percentages allocated to power block and fertilizer in the HECA Power Generation for SB 1368 Emission Performance Standard Table for each project case (On-Peak, Off-Peak, and Daily Average).

F. Please provide detailed calculations and rationale for the calculations used to determine the Syngas Allocation to Power and Fertilizer that were used to determine the CO_2 emissions by emissions source. Please confirm this value is for the Daily Average case, and provide the values for the On-Peak and Off-Peak cases.

G. Please provide additional background information explaining the syngas allocation method used to determine CO_2 emissions from the fertilizer plant. This additional detail should explain the methodology sufficiently to ensure that CO_2 emissions from the fertilizer plant are not double counted when CO_2 emissions are sequestered in the urea produced.

H. The syngas allocation by section (see spreadsheet provided by applicant for May 10, 2013 meeting, attached to TN 70829) does not include a value for the Common allocation. The CO_2 emissions from components identified elsewhere in the spreadsheet designated as "Common" are calculated using the Power Allocation percentage in the spreadsheet. Please confirm or provide the correct Common allocation percentage.

I. Please provide the air separation unit's power consumption value expected for the On-Peak, Off-Peak, and Daily Average cases. This can be presented with apportionment to the power block and fertilizer plant if detailed calculations and rationale for that apportionment basis (based on use of the produced oxygen and nitrogen and its later products, hydrogen and CO_2, used for power and fertilizer production) are provided.

J. The applicant stated that the power consumption for initial CO_2 compression that is completed at the HECA site was sufficient to provide CO_2 at a pressure necessary for geologic sequestration.

- Please confirm that means that the compression completed at the HECA site and the power consumed by the compressors on the HECA site is adequate to provide a level of compression that is sufficient to provide pressure necessary for geologic sequestration, or if the power consumption calculations include additional compression power consumption beyond that which is actually done at the HECA site that would be needed to obtain the desired pressure.
- Please indicate if the assumed pressure necessary for geologic sequestration is the same pressure that is required by Oxy Elk Hills (OEHI) to inject the CO_2 into the Stevens formation.
- Please indicate how much pressure is lost in terms of equivalent power consumption from the CO_2 custody transfer point to the point of receipt at the OEHI central EOR facility for initial injection into the oil reservoir.

K. A review of the emissions tables indicates that there are changes to some of the emissions calculation assumptions provided in Appendix E, such as the fuel consumption in the gas turbine and duct burners.

- Please update Appendix E as necessary to include all of these changes as well as the other recent changes to project (addition of fluxant, removal of ammonia export).
- Please provide emissions calculation (AQ and GHG) for both the on-peak and off-peak cases clearly showing fuel flow to the combustion turbine and duct burners for each case.
- Please show how HECA off-peak operations would impact other emission sources and provide information on changes to the major component stream flows that may occur during these operating conditions (such as, does amount of CO_2 shipped to OEHI go up during off-peak operations, or does the CO_2 concentration in the hydrogen rich fuel go up to maintain a constant CO_2 emissions profile for the HRSG and coal dryer stacks for On- and Off-Peak operations?).

L. Based on Table 2-10 provided in the Amended AFC, during maximum ammonia production, referred to as off-peak operation, production of the other fertilizer components do not increase.

- Please provide data/calculations confirming the plant will have adequate ammonia storage facilities capable of handling the increased ammonia that would be produced during off-peak operations.
- Please indicate if the rate of ammonia consumed by the plant varies with respect to the fertilizer products during on-peak and off-peak operations, and if so please provide the on- and off-peak operation case production rates for nitric acid, urea, and UAN production.
- Please clearly indicate if HECA's ammonia use is higher than its production rate during on-peak operations, or if other components of fertilizer production, including the intermediate products like nitric acid, would increase with the increase in ammonia production during off-peak periods of operation.

M. Please provide a detailed list of the monitoring and recordkeeping methods and procedures that are proposed to be used to demonstrate ongoing compliance with the SB 1368 emission performance standard (EPS) during facility operations. This should include:

- Monitoring methods and locations to establish CO_2 emissions from all onsite project sources, including fugitive emissions sources.
- Monitoring methods and locations to establish net electricity generation values for all electricity consumed and generated.
- Recordkeeping measures to ensure completeness and accuracy of data collected.
- Coordination with OEHI to obtain necessary data on carbon sequestration to support the value of the sequestered CO_2 that can be used to account for the amount of CO_2 shipped to OEHI.

N. As an adjunct to GHG, please confirm the current planned and unplanned outage as the basis for reliability. Currently, our understand is as follows:

- Planned: Two 1-week planned maintenance outages with 15-hour ramping allowance for 351 hours
- Planned: Two cold-start cycles, each 4 days long for a total of 192 hours
- Unplanned: 219 hours of outage based on 91.3% equivalent availability factor (EAF), calculated as follows: (1-0.913) x 8760 = 762 hours of total outage. 762 (hours of total outage) –351 (maintenance outage hours) –192 (cold start-up hours) = 219 hours (unplanned outage hours).

PROPOSED CONDITIONS OF CERTIFICATION

Staff proposes the following preliminary Conditions of Certification **GHG-1** through **GHG-5** to ensure proper recordkeeping and monitoring for GHG emissions and CO_2 sequestration as required for compliance with LORS. These conditions outline the requirements that staff is recommending; however, staff is continuing to work on the detailed requirements that need to be added to these conditions. The FSA/FEIS will include the final versions of these conditions.

STAFF PROPOSED CONDITIONS OF CERTIFICATION

GHG-1 The project owner shall prepare a CO_2 Emissions Performance Compliance Plan (EPCP). This plan shall include the operating, monitoring and recordkeeping methods used to demonstrate the onsite CO_2 emissions from HECA. This plan shall:

- Detail the methods used to monitor the operating parameters and CO_2 emissions and CO_2 quantities exported from the site as required to show compliance with the EPS.
- Detail the measures used to minimize onsite CO_2 emissions "leakage" from venting and other upset events.
- Detail the methods to compute and document the amount of CO_2 sequestered by the CO_2 user receiving the exported CO_2.
- Define the steps to be undertaken to demonstrate compliance with SB 1368.
- Detail the methods used to document all GHG emissions of the stationary and mobile emissions sources not subject to SB 1368 compliance but subject to ARB's GHG emissions reporting regulations, the AB32 Cap and Trade regulation, and other federal or state regulations.

<u>Verification:</u> The project owner shall provide a copy of the CO_2 EPCP to the compliance project manager (CPM) for review and approval at least six months prior to the initial commissioning of the project's gasification unit. Any updates to the CO_2 EPCP necessitated by project owner initiated changes to the monitoring and recordkeeping methods, or those necessary to maintain regulatory compliance, shall be provided to the CPM for review and approval at least 30 days prior to the initiation of any changes to the plan. Additionally, this plan shall be re-approved every two years, with the project owner providing a plan re-approval request letter with a copy of the current CO_2 EPCP for review and approval to the CPM at least 30 days before the end of every other calendar year after the project has started commercial operation. The plan re-approval letter shall document any changes to the CO_2 EPCP that have occurred over the period since its last approval by the Energy Commission and shall state the reasons for any needed changes.

GHG-2 The project owner shall operate the facility in compliance with the CO_2 Emissions Performance Compliance Plan after its approval. The project owner shall cease operations of the gasifier if: 1) the project owner cannot demonstrate compliance with the CO_2 Emissions Performance Compliance Plan; or 2) if OEHI permanently stops accepting the CO_2 for sequestration; or 3) temporarily as necessary for ongoing compliance with CO_2 venting limits provided in Air Quality Condition of Certification **AQ-11-85**.

<u>Verification:</u> The project owner shall provide documentation of compliance with this condition to the CPM in the annual report required by Condition **AQ-SC8**. This report shall verify compliance with SB1368 regulations.

GHG-3 The project owner shall obtain from the CO_2 user a CO_2 Emissions Sequestration Plan (CO_2 ESP) that identifies the preparation of injection wells either by retrofitting existing ones or drilling new wells to meet requirements for injection wells intended for the purpose of long term storage, operating, monitoring, recordkeeping, and closure methods used to demonstrate the quantity of CO_2 that is sequestered annually. The CO_2 ESP shall also identify and update as needed the long-term plan for future petroleum production and the financing instrument for post injection site care (PISC) including a corrective action plan, and eventual well closure to assure permanent CO_2 sequestration. The project owner/CO_2 supplier shall also obtain from the CO_2 user records of the annual CO_2 emission sequestration quantities from the CO_2 user and maintain these records for the life of the project. This plan shall:

- Detail plans to retrofit existing wells and construct new wells in compliance with the requirements for Class VI injection wells found at 40 CFR § 146.86 and related articles, which include requirements for casing and cementing of injection wells, except that the injector would not have to obtain the actual permits for Class VI wells and also that any mention of "Director" in those requirements must be replaced with compliance project manager (CPM).
- Detail the methods used to monitor the operating parameters and CO_2 emissions directly and indirectly related to the CO_2 sequestration process, including fugitive emissions and indirect emissions from electricity use, and the quantity of supplied CO_2 that has been sequestered annually. This shall include a leak detection and repair (LDAR) program for all EOR piping components not regulated by an SJVAPCD LDAR requirement that are in CO_2 service.
- Detail the design measures used to minimize and the monitoring methods used to measure potential CO_2 emissions "leakage" from the injection and production wellheads/well casings, including the monitoring of wells that are in production surrounding the EOR component's well field pattern areas and monitoring aboveground ambient CO_2 concentrations to detect surface leakage.

- Detail the design measures used to minimize and the monitoring methods used to measure potential CO_2 emissions “leakage” from tank venting for all tanks that contain CO_2 in gas phase or dissolved in liquids in the EOR component’s tanks.
- Detail the methods used to detect whether there is underground formation leakage of CO_2 emissions related to the CO_2 injection process that could be due to unknown faults or cracks in the cap rock, including the monitoring methods that will be used for determining CO_2 leakage in all of the petroleum and groundwater bearing formations located above the Steven’s formation.
- Detail the physical and chemical methods used to show how much CO_2 is sequestered during and after EOR and the monitoring methods used to ensure the CO_2 remains sequestered.
- Detail the physical and chemical methods used to show how much CO_2 is contained in products moved off site.
- Detail the methods used to monitor the operating parameters and CO_2 emissions of the stationary and mobile emissions sources subject to ARB’s GHG Mandatory Reporting regulations, the AB32 Cap and Trade regulation, or other federal or state regulations.
- Detail the long term plan for future petroleum production and eventual well closure to assure that the CO_2 is permanently sequestered. This part of the plan shall include a financial instrument, such as a bond or other financial assurance that will assure that funds will be available for well plugging, PISC, and closure whenever that may occur, and ongoing maintenance of the oil field to ensure long term geologic sequestration.

Verification: The project owner/CO_2 supplier shall provide a copy of the CO_2 ESP to the CPM for review and approval prior to the start of the initial commissioning of the project’s gasification unit. Any updates to the CO_2 ESP necessitated by CO_2 user initiated changes to the monitoring and recordkeeping methods, or necessitated to maintain regulatory compliance, shall be provided to the CPM for review and approval at least 30 days prior to the initiation of any changes to the CO_2 ESP. Additionally, this plan shall be re-approved every two years, with the project owner providing the CO_2 users plan re-approval request letter with a copy of the current CO_2 ESP for review and approval to the CPM by December 1st of every other calendar year once HECA starts commercial operation. The plan re-approval letter shall document any changes to the CO_2 ESP that has occurred over the period since its last approval by the Energy Commission and shall state the reasons for any needed changes. The ESP update can be combined with the EPCP update as appropriate.

GHG-4 The project owner shall complete GHG emissions estimates as required by federal and state mandatory reporting and AB 32 Cap and Trade regulations, shall obtain copies of the GHG emissions estimates and CO_2 sequestration records of Occidental Petroleum and shall provide annual emissions data to the California Air Resources Board (ARB) under their GHG Mandatory Reporting requirements. The project owner shall maintain copies of all of these records, including copies of required GHG emissions verifications by an independent GHG verifier as certified by the ARB, at the project site for a period of at least five years, or longer if required by regulation.

Verification: The project owner shall provide annual GHG emissions and CO_2 sequestration record data as required by the ARB's Mandatory Reporting regulation and Cap and Trade regulation to the ARB by April 10 of each year. The project owner shall provide to the CPM a letter certifying that the data has been properly reported and accepted by the ARB within 30 days of receiving such notification from ARB. The project owner shall provide copies of the detailed GHG emissions estimates and CO_2 sequestration records required by this condition to the CPM when requested and shall make copies available at the project site at the request of representatives of the Energy Commission, San Joaquin Valley Air Pollution Control District, California Air Resources Board, or the United States Environmental Protection Agency.

GHG-5 The project owner must adopt industry standard and verified methodologies to keep an accurate count of the amounts of CO_2 transferred to OEHI, the amounts injected underground, the amounts recovered with extracted fluids, the amounts reinjected, the amounts lost through surface equipment, and the amounts leaked to the surface after injection. The difference between the amounts transferred and all the losses constitutes the amount of CO_2 that has been sequestered. Both measured and calculated amounts shall be reported on an annual basis. The project owner shall demonstrate compliance with California's Environmental Performance Standard by annually accounting for annual MWh sold and all carbon dioxide generated at HECA, received at OEHI, vented, stored underground, and leaked as described in the equation in the portion of the staff assessment dealing with quantification of sequestered CO_2 volumes.

Verification: No later than 60 days before commencement of injection, the owner shall present to the CPM for approval the methods used to detect and quantify any amounts of CO_2 lost. These include losses through surface equipment, losses though exported fluids, and losses from leaks of injected CO_2 to the surface. Measured and calculated quantities shall be included in the Annual Compliance Report (ACR).

DISTRICT DOC CONDITIONS OF CERTIFICATION

The Determination of Compliance (DOC) conditions related to GHG emissions are included with the other DOC conditions in the **Air Quality** section of this document.

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LIST OF ACRONYMS

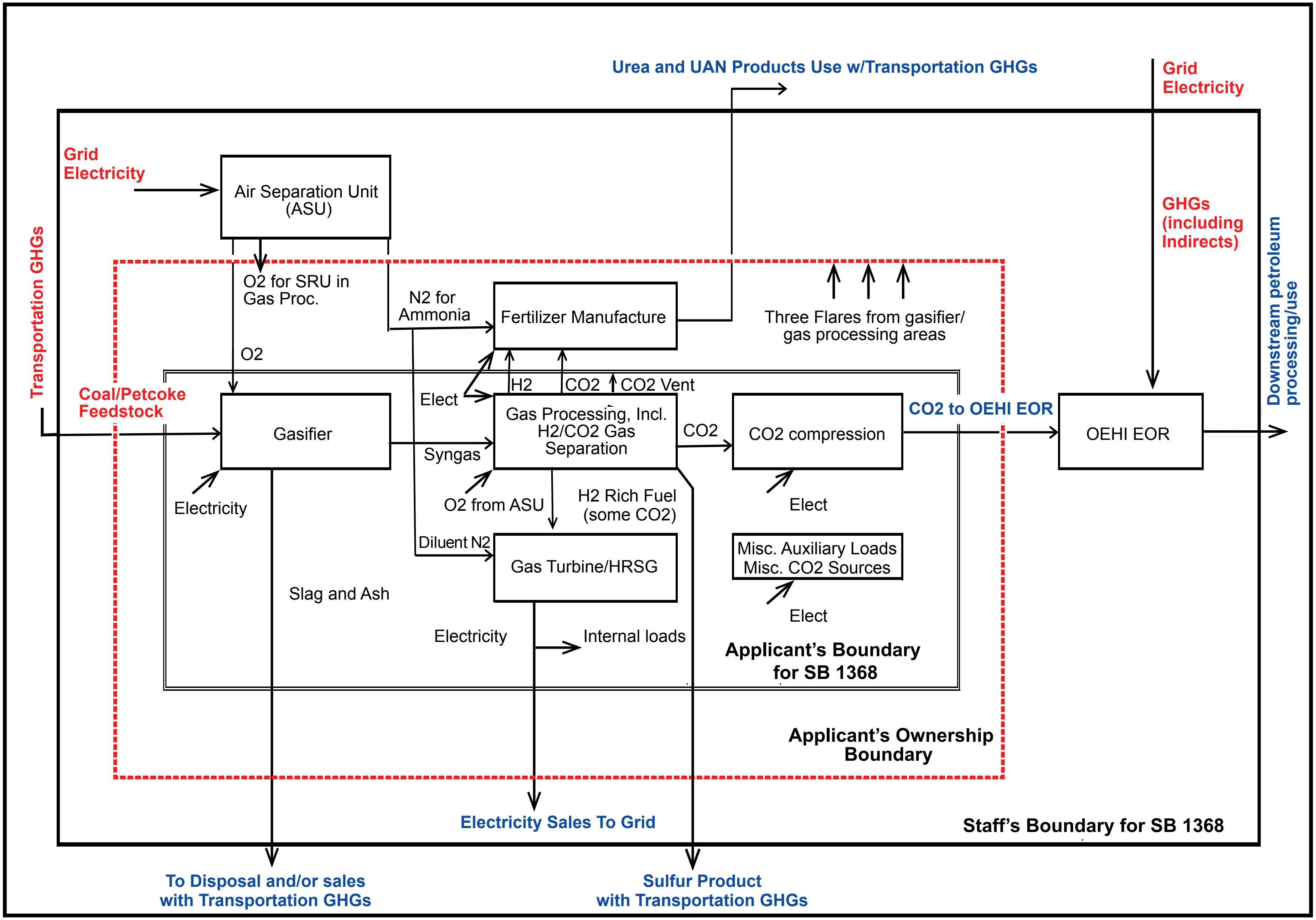
3-D	Three-dimensional
AB	Assembly Bill
AB32	California Global Warming Solutions Act of 2006 (Assembly Bill 32)
ACEC	Area of Critical Environmental Concern
AFUDC	Allowance for Funds used During Construction
AGR	Acid Gas Removal
AIR	Association of Irritated Residents (an Intervenor)
ARB	California Air Resources Board
AoR	Area of Review
API	American Petroleum Institute
BACT	Best Available Control Technology
bbl	Barrel (42 gallons)
BGL	Below Ground Level
BLM	Bureau of Land Management
bpd	Barrels per day
CAA	Clean Air Act
CalEPA	California Environmental Protection Agency
CCCC	California Climate Change Center
CCPI	Clean Coal Power Initiative
CCR	California Code of Regulations
CCS	Carbon Capture and Storage
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
C_{fv}	Fugitive and vented CO_2 associated with injection and production
CH_4	Methane
C_l	CO_2 emitted through leakage
CO_2	Carbon Dioxide
CO2E	Carbon Dioxide Equivalent
COC	Condition of Certification
COS	Carbonyl Sulfide
C_p	CO_2 measured at the custody-transfer point
CPM	Compliance Project Manager
CPUC	California Public Utilities Commission
CRP	CO_2 Recovery Plant
C_s	Sequestered CO_2
C_t	Total CO_2 received from HECA
CTB	Central Tank Battery
CTG	Combustion Turbine Generator
DEIS	Draft Environmental Impact Statement
DOC	Determination of Compliance
DOE	United States Department of Energy
DOGGR	Division of Oil, Gas & Geothermal Resources
DWR	California Department of Water Resources

EAP	Energy Action Plan
EHOF	Elk Hills Oil Field
EHU	Elk Hills Unit
EIR	Environmental Impact Report
EIS	Environmental Impact Statement
EJ	Environmental Justice
EO	Executive Order
EOR	Enhanced Oil Recovery
EPCP	Emissions Performance Compliance Plan
EPS	Emission Performance Standard
ESP	Emissions Sequestration Plan
FDOC	Final Determination of Compliance
FEIS	Final Environmental Impact Statement
FERC	Federal Energy Regulatory Commission
FSA	Final Staff Assessment
FSA/FEIS	Final Staff Assessment/Final Environmental Impact Statement
ft	Feet
g	Gravity constant
GCC	Global Climate Change
GHG	Green House Gas
GWh	Gigawatt-hour
GWP	Global Warming Potential
H_2S	Hydrogen Sulfide
HECA	Hydrogen Energy California Project
HFCs	Hydrofluorocarbons
hp	Horsepower
HP	High Pressure (steam)
hr	Hour
HRSG	Heat Recovery Steam Generator
IEPR	Integrated Energy Policy Report
IGCC	Integrated Gasification Combined Cycle
IOU	Investor-Owned Utility
IPCC	Intergovernmental Panel on Climate Change
ISO	California Independent System Operator
km	kilometer
kV	Kilovolt
LA	Los Angeles
LADWP	Los Angeles Department of Water and Power
lbs	Pounds
LDAR	Leak Detection and Repair
LHOF	Lost Hills Oil Field
LORS	Laws, Ordinances, Regulations, and Standards
LP	Low Pressure (steam)
LSP	Lateral Spill Point
MBB	Main Body B
md	Millidarcy

MIT	Massachusetts Institute of Technology or Mechanical Integrity Testing
MMBtu	Million British Thermal Units
MMP	Minimum Miscibility Pressure
mmscfd	Million standard cubic feet per day
MMTA	Million Metric Tons Annually
MRV	Monitoring, Reporting, and Verification (e.g. MRV plan)
MT	Metric tonnes
MT/y	Metric tonnes per year
MW	Megawatt
MWh	Megawatt-hour
NA	North American
NASA	National Aeronautics and Space Administration
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
N_2O	Nitrous Oxide
NO	Nitric Oxide
NOAA	National Oceanic and Atmospheric Administration
NOx	Oxides of Nitrogen or Nitrogen Oxides
NRU	Nitrogen Reinjection Unit
NW-SE	North West – South East
NWS	North West Stevens
O_3	Ozone
OEHI	Occidental of Elk Hills, Inc.
OII	Order Initiating an Informational
OTC	Once-Through Cooling
OXY	Occidental Petroleum
PDOC	Preliminary Determination of Compliance
petcoke	Petroleum Coke
PFCs	Perfluorocarbons
PISC	Post injection site care
POU	Publicly Owned Utility
ppm	parts per million
PSA	Pressure Swing Adsorption or Preliminary Staff Assessment
PSA/DEIS	Preliminary Staff Assessment/Draft Environmental Impact Statement
PSD	Prevention of Significant Deterioration
psig	Pound-force per square inch gauge
QFER	Quarterly Fuel and Energy Report
RCF	Reinjection Compression Facility
RPS	Renewables Portfolio Standard
RR	Reef Ridge
SB	Senate Bill
SCE	Southern California Edison
SCTF	Shute Creek Treating Facility
SDG&E	San Diego Gas and Electric
SEI	Supplemental Environmental Information
SF	San Francisco

SF_6	Sulfur hexafluoride
SJVAPCD	San Joaquin Valley Air Pollution Control District
SO_2	Sulfur Dioxide
SOZ	Shallow Oil Zone
SRU	Sulfur Recovery Unit
SWRCB	State Water Resource Control Board
TCR	The Climate Registry
TEG	Triethylene Glycol
TID	Turlock Irrigation District
TPY, t/y	Tons per Year
UIC	Underground Injection Control
USDW	Underground sources of drinking water
U.S. EPA	United States Environmental Protection Agency
USGS	United States Geologic Survey
VOC	Volatile Organic Compounds
WAG	Water Alternating Gas
WCI	Western Climate Initiative
WECC	Western Electricity Coordinating Council
yr	Year

CARBON SEQUESTRATION and GREENHOUSE GAS - FIGURE 1
Hydrogen Energy California - SB 1368 EPS Calculation Assumptions



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: CEC Staff

CULTURAL RESOURCES

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SUMMARY OF CONCLUSIONS

Staff tentatively concludes that the proposed Hydrogen Energy California project may have a significant direct impact on historical resources and historic properties, as defined by the California Environmental Quality Act and Section 106 of the National Historic Preservation Act. Impacts may be incurred upon known, significant archaeological and historic built environment resources. Additionally, the proposed project could result in significant adverse changes to an unknown number of as-yet-unidentified, buried archaeological resources. Such potential impacts include the removal or destruction of archaeological materials during trenching for linear project facilities as well as grading and mass excavation of the proposed project site. The applicant has not assessed portions of the area in which the proposed project may affect cultural resources as of the time of this writing, preventing California Energy Commission and United States Department of Energy staff from conducting a complete impact analysis under State and federal environmental laws. Energy Commission staff will continue to work with the applicant, Occidental of Elk Hills, Inc., and Department of Energy to resolve all outstanding information needs prior to publication of the Final Staff Assessment/Final Environmental Impact Statement. Although Energy Commission staff has proposed conditions of certification for the proposed project, additional conditions are likely to be needed because of the incomplete nature of the information currently available to staff. The additional information that staff requires to prepare and complete a Final Staff Assessment/Final Environmental Impact Statement is discussed in this section under the heading “Unresolved Areas Relating to Cultural Resources”.

Although the adoption and implementation of Conditions of Certification **CUL-1** through **CUL-8** would reduce the currently identifiable potential impacts of the proposed project on cultural resources to a less-than-significant level, the incompleteness of the cultural resources analysis available to staff requires staff to tentatively conclude that the proposed project would result in one or more significant impacts/adverse effects on cultural resources. The level of significance after mitigation of significant impacts/adverse effects is currently unknowable.

As a result of ethnographic studies, staff concludes that there are no ethnographic resources that will be impacted by the proposed project. The ethnographic information provided in this assessment is intended to support prehistoric archaeological findings known in the project vicinity or likely to be discovered during construction should the project be approved. Specifically, staff concludes that burials would likely be encountered should the proposed project be built and it is intended that the ethnographic section should be used to support monitoring efforts in a proactive fashion to identify burial features at the earliest opportunity and point of discovery.

[1] Roark: historic archaeology; Gates: ethnography; Mourkas: historic built environment; Bagwell: prehistoric archaeology.

Staff has considered environmental justice populations in its analysis of the proposed project. Staff has not identified significant adverse direct, indirect, or cumulative cultural resources impacts that would affect environmental justice populations. However, receipt of the cultural resources information specified under the heading “Unresolved Areas Relating to Cultural Resources” could result in the identification of such impacts on environmental justice populations. Staff will disclose any cultural resources-related impacts on environmental justice populations in the final staff assessment/final environmental impact statement.

INTRODUCTION

This cultural resources assessment identifies the potential impacts of the proposed Hydrogen Energy California (HECA) project on cultural resources, including historic properties, historical resources, and unique archaeological resources, as defined under federal and state laws and regulations. The term “cultural resource” means any tangible or observable evidence of past human activity, regardless of significance, found in direct association with a geographic location, including tangible properties possessing intangible traditional cultural values. Under California state law, historical resources may include buildings, sites, structures, objects, areas, places, records, and manuscripts that are historically or archaeologically significant, or are significant in the architectural, engineering, scientific, economic, agricultural, educational, social, political, military, or cultural annals of California. See Title 14, California Code of Regulations, sections 4852(a) and 15064.5(a)(3); and Public Resources Code, sections 5020.1(h, j) and 5024.1(e)(2, 4). Under federal and state historic preservation law, cultural resources generally must be at least 50 years old to have sufficient historical importance to merit consideration of eligibility for listing in the National Register of Historic Places (NRHP) or the California Register of Historical Resources (CRHR). A resource less than 50 years of age must be of exceptional historical importance to be considered for listing. Three broad classes of cultural resources are considered in this assessment: prehistoric, ethnographic, and historic.

Prehistoric archaeological resources are those materials relating to prehistoric human occupation and use of an area. These resources may include sites and deposits, structures, artifacts, rock art, trails, and other traces of Native American human behavior. In California, the prehistoric period began over 12,000 years ago and extended through the eighteenth century until 1769, when the first Europeans settled in California.

Ethnographic resources are those materials important to the heritage of a particular ethnic or cultural group, such as Native Americans or African, European, or Asian immigrants. They may include traditional resource collecting areas, ceremonial sites, topographic features, value-imbued landscapes, cemeteries, shrines, or ethnic neighborhoods and structures. Ethnographic resources are variations of natural resources and standard cultural resource types. They are subsistence and ceremonial locales and sites, structures, objects, and rural and urban landscapes assigned cultural significance by traditional users. The decision to call resources "ethnographic" depends on whether associated peoples perceive them as traditionally meaningful to their identity as a group and the survival of their lifeways.[2]

Historic-period resources are those materials, archaeological and architectural, usually associated with Euro-American exploration and settlement of an area and the beginning of a written historical record. They may include archaeological deposits, sites, structures, traveled ways, artifacts, or other evidence of human activity. Under federal and state requirements, historical cultural resources must be greater than 50 years old to be considered of potential historic importance. A resource less than 50 years of age may be historically important if the resource is of exceptional importance.

For the HECA project components, staff provides an overview of the environmental setting and history of the project area, an inventory of the cultural resources identified in the project vicinity, and an analysis of the potential impacts from the proposed project using criteria from the California Environmental Quality Act (CEQA). The primary concern is to ensure that all potential impacts are identified and that conditions are set forth that ensure that impacts are mitigated below the level of significance.

If cultural resources are identified, staff determines whether there may be a project-related impact to them. If the cultural resources cannot be avoided, staff determines whether any of the impacted resources qualify as historical resources or unique archaeological resources under CEQA, or, in conjunction with United States Department of Energy (DOE) personnel (hereafter included under the term "staff" for the purposes of this joint document), qualify as a historic property under Section 106 of the National Historic Preservation Act (NHPA). If impacted resources are eligible for the register, staff recommends conditions of certification (Conditions)—which the Commission may or may not adopt—on the portion of the proposed project that is under the Energy Commission's permitting purview: the proposed HECA components. These conditions will be purposed to reduce cultural resource impacts to a less-than-significant level. For the proposed enhanced oil recovery (EOR) project components on Occidental of Elk Hills, Inc. (OEHI) property, staff recommends mitigation measures that ensure that impacts to the identified cultural resources are reduced to a less-than-significant level. In these recommended mitigation measures, staff identifies the agency that would be responsible for implementing and monitoring them.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Projects licensed by the Energy Commission are reviewed to ensure compliance with all applicable local, state, and federal laws, ordinances, regulations, and standards (LORS). The LORS applicable to the project are listed in **Cultural Resources Table 1**.

As discussed in the Introduction to this preliminary staff assessment/draft environmental impact statement (PSA/DEIS), this document analyzes the project's impacts pursuant to both the National Environmental Policy Act (NEPA) and CEQA. The two statutes are similar in their requirements concerning analysis of a project's impacts. Therefore,

[2] A "lifeway," as used herein, refers to any unique body of behavioral norms, customs, and traditions that structure the way a particular people carry out their daily lives.

unless otherwise noted, staff's use of, and reference to, CEQA criteria and guidelines also encompasses and satisfies NEPA requirements for this environmental document.

Cultural Resources Table 1
Laws, Ordinances, Regulations, and Standards

Applicable Law	**Description**
Federal	
Historic Sites, Buildings, Objects, and Antiquities Act of 1935, as amended 16 U.S.C., §§461–467	Establishes national policy of acquisition, preservation, and management of historic and archaeological properties, including survey, recordation, research, and public education; establishes the National Park System Advisory Board and the National Park Service Advisory Council.
Protection of Historic Properties 36 C.F.R., part 800	An implementing regulation of the NHPA, Title 36, Code of Federal Regulations, part 800 requires federal agencies to consider the effects that federally permitted, funded, or approved projects would have on historic properties; consult with tribes, state historic preservation officers, and other parties; involve the public in the consultation proceedings; and afford the Advisory Council on Historic Preservation (ACHP) the opportunity to comment.
National Environmental Policy Act (NEPA) Public Law 91-90, 42 U.S.C., §§4321–4347; NEPA regulations	Establishes environmental policy for the nation; provides for an interdisciplinary approach for federal environmental planning; requires federal decision-makers to take environmental effects of federal actions into account; requires disclosure of environmental impacts to the public; obligates federal agencies to seek solutions to environmental impacts; mandates cooperation with other agencies; and directs federal agencies to involve the public.
Executive Order (EO) 11593 of May 13, 1971; 36 *Federal Register*, 8921	Provides for the protection and enhancement of the cultural environment; requires federal agencies to inventory their cultural resources and to record, to professional standards, any cultural resource that may be altered or destroyed.
Archaeological and Historic Preservation Act of 1974 16 U.S.C., §469 et seq.	Addresses impacts on cultural resources resulting from federal activities that would significantly alter the landscape. The focus of the law is data recovery and salvage of scientific, prehistoric, historic, and archaeological resources.
Secretary of the Interior's Standards and Guidelines for Archaeology and Historic Preservation [1983], as revised 48 *Fed. Reg.,* 44716–44742	Establishes qualifications standards for historic preservation professionals, evaluation standards for cultural resources, and guidelines for technical reports and the documentation of cultural resources.
American Indian Religious Freedom Act 42 U.S.C., §1996 et seq.	Protects the right of Native Americans and other indigenous groups to exercise their traditional religions.
EO 13287 Preserve America	Where consistent with executive branch department and agency missions, governing law, applicable preservation standards, and where appropriate, executive branch departments and agencies ("agency" or "agencies") shall advance this policy by pursuing partnerships with state and local governments, Indian tribes, and the private sector to promote the preservation of the unique cultural heritage of communities and of the nation and to realize the economic benefit that these properties can provide.

Applicable Law	Description
Use of Human Subjects, 46 C.F.R., §101	Provides for non-disclosure of confidential information that may otherwise lead to harm of the human subject divulging confidential information.
DOE Management of Cultural Resources, Policy DOE P 141.1	Establishes the DOE's responsibility to comply with federal historic preservation laws, regulations, and polices; focus is on tribal consultation and cultural resource management at DOE-owned facilities.
DOE American Indian & Alaska Native Tribal Government Policy DOE Order 144.1	Policy Principle IV. Identifies DOE's commitment to consult with Indian tribes about the effects of DOE undertakings on historic properties of concern to tribes. Specifies that this commitment ranges from the identification of historic properties through managing adverse effects.
State	
Pub. Resources Code, §5097.98(b) and (e)	Requires a landowner on whose property Native American human remains are found to limit further development activity in the vicinity until s/he confers with the Native American Heritage Commission (NAHC) and identifies Most Likely Descendents (MLDs) to consider treatment options. In the absence of MLDs or of a treatment acceptable to all parties, the landowner is required to reinter the remains elsewhere on the property in a location not subject to further disturbance.
Pub. Resources Code, §§5097.99 and 5097.991	Section 5097.99 establishes as a felony the acquisition, possession, sale, or dissection with malice or wantonness of Native American remains or funerary artifacts. Section 5097.991 establishes a state policy requiring the repatriation of Native American remains and funerary artifacts.
California Health and Safety Code, §7050.5	Makes it a misdemeanor to disturb or remove human remains found outside a cemetery. It also requires a project owner to halt construction if human remains are discovered and to contact the county coroner.
California Civil Code §1798.24	Provides for non-disclosure of confidential information that may otherwise lead to harm of the human subject divulging confidential information
California Public Records Act California Government Code, §6250.10	Provides for non-disclosure of records that relate to archaeological site information and reports maintained by, or in the possession of, the Department of Parks and Recreation, the State Historical Resources Commission, the State Lands Commission, the NAHC, another state agency, or a local agency, including the records that the agency obtains through a consultation process between a California Native American tribe and a state or local agency.
Local	
County of Kern General Plan, Land Use/Conservation/ Open Space Element (Chapter 1.10.3), Cultural Resources Policy 25	The county will promote the preservation of cultural and historic resources which provide ties with the past and constitute a heritage value to residents and visitors. Implementation Measures: K. Coordinate with the California State University, Bakersfield's Archaeology Inventory Center. L. The county shall address archaeological and historical resources for discretionary projects in accordance with CEQA. N. The county shall develop a list of Native American organizations and individuals who desire to be notified of proposed discretionary projects. This notification will be accomplished through the established procedures for discretionary projects and CEQA documents. O. On a project specific basis, the county planning department shall evaluate the necessity for the involvement of a qualified Native American monitor for grading or other construction activities on discretionary projects that are subject to a CEQA document.
Western Rosedale Specific Plan, Cultural Resources Goal 1.	Goal 1. Protect areas of significant cultural or archaeological potential for future use. Policy 1. Require developers to demonstrate the cultural/archaeological potential for the project sites.

Applicable Law	Description
	Policy 2. Encourage preservation of any known sites of cultural or archaeological significance. Policy Implementation 1. In conjunction with the processing of discretionary permits developers shall be responsible for the preparation of site-specific cultural/archaeological studies unless this requirement is waived by the planning director. Recommendations contained in the studies shall be incorporated into the project. Policy Implementation 2. Alternatives to development, such as open space easements, shall be encouraged where cultural resources are known or suspected.
Interstate 5 at Highway 58 Rural Community Plan	General Provisions, Implementations and Policies 8. Should any archaeological or historical resource be unearthed during construction, work should be halted for not less than a 72-hour period in the area of the discovery until the finds can be assessed by an archaeologist and appropriate mitigation measures can be carried out.
Oglesby Specific Plan	General Provisions, Implementations and Policies 8. Should any archaeological or historical resource be unearthed during construction, work should be halted for not less than a 72-hour period in the area of the discovery until the finds can be assessed by an archaeologist and appropriate mitigation measures can be carried out.
Metropolitan Bakersfield General Plan	No cultural resources requirements.

SETTING

Information provided regarding the setting of the proposed project places it in its geographical and geological contexts and specifies the technical description of the project. Additionally, the archaeological, ethnographic, and historical, backgrounds provide the contexts for the evaluation of the historical significance of any identified cultural resources within the project area of analysis.

REGIONAL SETTING

The proposed HECA project is located in western Kern County within the southern San Joaquin Valley, a north–south trending valley within the Great Valley Geomorphic Province. The valley is bordered on the east by the Sierra Nevada mountain range and on the west by the South Coast Ranges. On the north end, the San Joaquin Valley is delimited by the confluence of the Sacramento and San Joaquin rivers and on the south end by the Tehachapi and San Emigdio mountains (Jennings and Strand 1969; Smith 1964). The valley is a vast trough filled with sedimentary deposits, the oldest of marine origin and the youngest resulting from the erosion of the surrounding mountains and deposition of the eroded material as alluvium deep beneath the proposed project site. As with the rest of the southern San Joaquin Valley, the project site is situated between two seismically active regions. The closest known faults classified as active by the State of California Geologic Survey are the San Andreas Fault located approximately 21 miles to the west, the White Wolf fault located approximately 23 miles to the southeast, and the Pleito Thrust located approximately 27 miles south of the proposed project site. (URS 2012a:5.15-3, 5.15-4.)

The proposed HECA project's carbon dioxide (CO_2) pipeline extends into the Elk Hills, which are near the western border of the San Joaquin Valley. The South Coast Ranges flank this area to the west and form a natural barrier to coastal moisture and winds, creating a rain shadow on the eastern side of the range that encompasses the current project site and linear alignments. The local climate is characterized by hot dry summers and mild winters with precipitation almost exclusively in the winter. The annual rainfall in the project area is less than 4.7 inches and mostly occurs September through April. (URS 2012a:5.3-4.) Because of the arid nature of this portion of the Coast Ranges–Great Valley interface, the nearby slopes are drained only by intermittent creeks, including numerous unnamed gullies and drainages which cross the flank of the Elk Hills. These small intermittent drainages have maintained a low but fluctuating discharge for much of the Pleistocene and Holocene, building a series of small alluvial fans along the northeastern side of the Elk Hills (URS 2012a:5.15-3).

PROJECT, SITE, AND VICINITY DESCRIPTION

The project site and the HECA project's valley floor linear components bear the signs of 140 years of farming and ranching. These activities are evident by the crops, grain silos, and sparse residential settlement in the area. The struggle to keep the land sufficiently watered for crop and stock-raising but protected from floods is manifested in the project vicinity by the numerous canals, ditches, and levees (JRP 2012:8, 20–22). Expectable historical archaeological resources associated with farming, ranching, and residence include filled outhouse pits (privy pits) and wells, refuse scatters, buried trash pits, structural remnants, and buried, filled water conveyance features.

The HECA project's CO_2 pipeline and enhanced oil recovery (EOR) activities in the Elk Hills are sited in a different historical environment from the project site and other linear features. Discoveries of oil and asphalt in the Buena Vista Lake area and McKittrick, respectively, during the late 1890s sparked oil exploration of the Elk Hills in the early 1900s. In 1912, President William H. Taft created the Naval Petroleum Reserve No. 1 (NPR-1) by executive order. (Nachmanoff et al. 1999:20–21.) NPR-1 passed into private ownership about 1999. The 110 years of oil development in Elk Hills has dotted the area with well heads, derricks, pumps, underground and aboveground pipelines, storage tanks, and control buildings. These built environment features are a mix of historic (at least 50 years old) and recent builds. Oil and gas development in Elk Hills resulted in numerous historic archaeological sites, which mainly consist of structural foundations, abandoned industrial equipment, and refuse scatters. Ranching features, such as corrals, have also been found in the EOR area. (Stantec 2012a:4.5-4, 4.5-5.)

<u>Environmental Setting</u>

Identifying the kinds and distribution of resources necessary to sustain human life in an environment, and the changes in that environment over time, is central to understanding whether and how an area was used during prehistory and history. During the time that humans have lived in California, the region in which the proposed project is located, the southern San Joaquin Valley, has undergone several climatic shifts. These shifts have resulted in variable availability of vital resources, and that variability has influenced the scope and scale of human use of the project vicinity. Consequently, it is important to consider the historical character of local climate change, or the paleoclimate, and the effects of the paleoclimate on the physical development of the area and its ecology. The following discussion relies heavily on the applicant's geotechnical study and geoarchaeological literature review (Hale et al. 2012:46–59; URS 2009a).

Despite the low precipitation in the project vicinity, several large lakes occupied the southern San Joaquin Valley throughout the late Pleistocene and Holocene epochs. The largest of these lakes was Tulare Lake, approximately 30 miles north of the project site. Tulare Lake has now been drained for agricultural purposes, but it formerly extended over as much as 617 square miles in area, supporting a large and productive marshland around its margins. The smaller Buena Vista basin lies at the southern margin of the San Joaquin Valley, bordered on the north by the Kern River alluvial fan and by the Elk Hills on the northwest. Two shallow lakes, Buena Vista and Kern, formerly lay in this basin and usually received most or all of the flow of the Kern River. During wet years these lakes merged into a single body of water and drained into Buena Vista Slough at the base of the Elk Hills, which in turn flowed northwest into Tulare Lake. Historically, both of these lakes were also known to be partially or completely dry. Both lakes have now been reclaimed for agricultural purposes, but a small portion of Buena Vista Lake remains along its former northern shore, at the base of Elk Hills (Jackson et al. 1999). The project site is located within the former Buena Vista Slough near the foot of the Elk Hills. The proposed process water line would follow the route of the Kern River and Buena Vista Slough north. The proposed CO_2 line would cross the Buena Vista Slough and the Kern River west into the Elk Hills. The proposed natural gas line would head north and cross the Buena Vista Slough, extensive Kern River alluvial fans, and multiple branches of Kern River.

The environmental setting of the HECA project vicinity has changed dramatically over the last 200 years, primarily due to channelization of streams and deep ground water pumping for irrigated agriculture. Many of the plants and animals associated with the wetland habitats are extinct or rare. The setting described here is a discussion of the landscape as it likely appeared during prehistoric and protohistoric occupations of the valley, drawing heavily from historic records.

The historic plant and animal communities in project vicinity can be divided into two general categories: wetland habitats on the valley floor and dryer habitats on the floodplain and foothills. The proposed project site and process water line are located in former lake and marsh wetland habitats. The proposed CO_2 line passes through both marsh and foothill habitats. Finally, the proposed natural gas line would begin in a former marshy wetland setting then extend north, crossing the historic setting of dryer floodplains and former streambank riparian wetlands.

Plants associated with the historic Buena Vista Slough and the margins of Buena Vista and Kern lakes included common tule, sedge, cat-tail, water plaintain, and black and sandbar willows. The riparian habitat along the Kern River was characterized by Fremont and black cottonwood, red and yellow willow, oak, buttonwillow, Oregon ash, Canadian waterweed, and duckweed plant. Migratory waterfowl and fish were common in these wetland habitats. Some of these species included coots, ducks, geese, swans, cormorants, and pelicans. In the slower moving water Tule and Sacramento perch, Thicktail chub, and minnows such as the splittail and Sacramento blackfish were present. Also present in the faster-moving water in parts of Kern River the Sacramento sucker and Sacramento squawfish. Other important water dwelling species were the western pond turtle and freshwater mussel. Mammals that occupied the wetland areas included raccoon, river otter, mink, tule elk, and beaver. (Hartzell 1992:63–80.)

The alluvial fans and floodplains of the valley floor are characterized by Lower Sonoran Grassland plant communities. Some of the plants noted here include greasewood, fescue, alkali pepperweed, California goldfields, goosefoot, and iodine bush. The foothills, including the Elk Hills, support little plant growth, primarily low shrubs and sparse grasses. Common birds in these dry environments are quail, mourning doves, hawks, and Golden eagle. The ornate shrew, broad-footed mole, black-tailed jackrabbit, Audobon's cottontail and brush rabbit were common rodents. The grasslands supported large mammals such as tule elk, black-tailed and mule deer, pronghorn antelope, and bighorn sheep. Notable predators of these smaller animals included coyote, kit fox, ringtails, striped and spotted skunks, long-tailed weasels, badger, grizzly and black bears, mountain lion, and bobcat. (Hartzell 1992.)

The proposed project would be located 17 mi southwest of Bakersfield and 1.5 mi northwest of Tupman. For the past 200 years until the present day, this part of Kern County has been used for agricultural purposes and resource-based oil exploration and production. The proposed project site is currently used for farming purposes, including cultivation of alfalfa, cotton, and onions. Land within the proposed controlled area to the northwest of the project site is currently used for grain storage and organic fertilizer production. Land surrounding the site footprint is also used primarily for farming purposes, particularly the cultivation of alfalfa, cotton, wheat, and pistachios. Local irrigation canals—including the West Side Canal/Outlet Canal, Kern River Flood Control Canal, and California Aqueduct (State Water Project)—are located to the south. Other nearby land uses include oil production, public utilities, and undeveloped areas. The Tule Elk State Natural Reserve is located east of the proposed project site.

Paleoclimate and Paleoecology

The proposed project is located in the southern San Joaquin Valley, a large interior valley composed of alluvial plains and river channels. Over the last 20 years pollen studies from lakes and marshes have provided a picture of the paleoclimate and paleoecology of this region. During prehistoric times, this region fluctuated between cool-and-moist and warm-and-dry periods. These fluctuations in temperature and moisture were influential to the character of human occupation of the region. Environmental changes also had important implications for the project vicinity specifically, because of its proximity to Buena Vista Lake and Slough. As the climate shifted, different kinds of resources were available, resulting in corresponding shifts in human settlement and subsistence patterns.

Recent pollen core analysis (Davis 1999) and synthesis of available information (Negrini et al. 2006) at Tulare Lake have resulted in a relatively well-defined history of lake highstands and associated environmental perturbations. The history of Buena Vista Lake fluctuations, however, has yet to be determined (Meyer et al. 2009:26). Given the hydrologic connection between the Tulare Lake and Buena Vista Lake basins, a similar Southern Sierra Nevada water sources, and the similarity in climate records from throughout the region, some scholars assume that Buena Vista Lake and Slough experienced perturbations in water level similar to Tulare Lake (Hale et al. 2012:49; Hartzell 1992:53; Meyer et al. 2006:26.)

These studies suggest that during the Late Pleistocene and Early Holocene (18,000 to 8000 B.P.) conditions in the southern San Joaquin Valley were cool and wet. In the uplands vegetation was dominated by juniper-pinyon-oak woodland, while giant sequoia lined the Sierra streams. The salt flats near lakes were characterized by greasewood. In the Early Holocene between 8500 and 7500 B.P. oaks gradually became the dominant tree species, suggesting a warming trend. On the valley floor, between 7000 and 4000 B.P. greasewood was replaced by shrub steppes also suggesting a long period of warmer and dryer weather. In contrast, the Late Holocene between 4000 and 2000 B.P. was colder and wetter. From 1000 B.P. to the present, the dry pattern has been dominant, interrupted only by increasing precipitation towards the end of the Medieval Climatic Anomaly and during the Little Ice Age (ca. 650 B.P.) (Culleton 2006; West et al. 2007:25.)

These changes were accompanied by changes in water levels within the local lakes and wetlands, throughout the late Pleistocene and Holocene. Scholars have proposed at least seven major fluctuations in lake levels during the past 11,500 years. Lake levels were higher during the early Holocene. Three highstands were identified at 9500–8000 B.P., 6900–6200 B.P. and 750–150 B.P. In addition, three lowstands were identified at approximately 9700, 6100, and 2750 B.P. (Hale et al. 2012:49.)

The timing of these lake level highstands and lowstands correlate with more widespread periods of landscape instability throughout the Central Valley. Several recent reviews of Central Valley geoarchaeology and geomorphology have identified local depositional events that have buried stable Holocene landforms and associated archaeological sites (Meyer et al. 2009; Rosenthal et al. 2007). Several major periods of deposition seem to have co-occurred throughout the greater region (Hale et al. 2012:50).

Periods of alluvial deposition are associated with both lake highstands and lowstands. During wetter periods, the carrying capacity and sediment load of watercourses is increased. During dryer periods, reduced vegetation cover may lead to increased erosion of formerly stable landforms (Hale et al. 2012:50).

Geology

The HECA project is located within the Great Valley Geomorphic Province of California. The Great Valley Province is an asymmetric trough filled with a thick sequence of sediments from Jurassic[3] to Recent age. The sediments within the valley range up to ten kilometers in thickness and were mostly derived from erosion of the Sierra Nevada mountain range to the east, with lesser material from the Coast Range Mountains to the west. The southern portion of the Great Valley Province is characterized as being a nearly flat surfaced north trending trough bounded by the Coast Ranges to the west and Sierra Nevada Provinces to the east. Tertiary[4] rocks, which were deposited nearly continuously from Cretaceous to Pleistocene time, are largely of marine origin and underlie a relatively thin cover of Quaternary[5] alluvium. The Tertiary rocks overlie

[3] The Jurassic Period (199.6±0.6–145.5±4 million years ago) spanned the end of the Triassic to the beginning of the Cretaceous periods. The Jurassic constitutes the middle period of the Mesozoic Era.

[4] The Tertiary period (65–1.8 million years ago) covered the Secondary and Quaternary periods.

[5] The Quaternary period is the youngest period of the Cenozoic era in the geologic time scale, spanning 2.588±0.005 million years ago to the present. It includes two geologic epochs: the Pleistocene (2.588 million years–11,700 B.P.) and the Holocene (the current epoch, 11,700 B.P. to the present). (Cohen et al. 2012.)

Jurassic-Cretaceous marine sedimentary rocks in the west side of the valley. Northwest-trending anticlines in the Tertiary strata are reflected by the gas and oil fields and by low hills in the valleys. (URS 2009a:8–9.)

Geomorphically, the proposed project is situated above, on, and near the northeastern face of the Elk Hills, which is an anticlinal[6] uplift along the western periphery of the San Joaquin Valley. The Elk Hills form the surface expression of an anticlinal fold composed of gravel and mudstone derived from the South Coast Ranges to the west. The Elk Hills are dissected by numerous streams that redeposit the material on an apron of small coalescing fans along the northeast flank of the hills, which abuts the much larger Kern River fan to the north. The surface deposits at the HECA project site and proposed linear alignments are described as Quaternary age alluvial gravel and sand of valley areas. Sediments underlying the Quaternary alluvium belong to the Pliocene- to Pleistocene-age Tulare Formation, which consists of alternating beds of sand and mudstone. These deposits are described as stream-laid, pebble gravels, sands, and clays; and are light gray in color. Pebbles are composed chiefly of Monterey siliceous shale and debris from bedrock in the adjacent Temblor Range. (Hale et al. 2012:48; URS 2009a:8–9.)

Geomorphology

Geomorphology is the scientific study of landforms and the processes that shape them. Geomorphologists seek to understand why landscapes look the way they do, reconstruct landform history and dynamics, and predict future changes through a combination of field observation, physical experiment, and modeling. Archaeologists use geomorphology to understand how archaeological resources were formed and to predict where archaeological material of various types can be found. Over time, objects, sites, and other constructed works are moved, buried, or exposed by wind, water, plant growth, animal activity, and other natural processes. Geomorphology is a technique that helps archaeologists to interpret physical clues in order to understand the specific nature of these changes. In the case of the proposed project, geomorphology can be used to estimate the preservation potential of geologic formations and the likely condition of preserved archaeological resources.

Two geomorphological investigations were completed by the applicant for the proposed project vicinity: a geotechnical field exploration program at the HECA project site and a geoarchaeological literature review (Hale et al. 2012:46–59; URS 2009a). While evaluating the previous HECA Application for Certification (AFC), a request for a primary geoarchaeological field study was the subject of six data requests:

- Data requests 78 and 79 (October 12, 2009)
- Data requests 143 (January 13, 2010)
- Workshop Data Request 23 (April 12, 2010)
- Data Requests 172 and 173 (October 26, 2010). (CEC 2009, 2010a, 2010b.)

In the April 2010 workshop, the applicant agreed to develop a plan for the combined geotechnical/ geoarchaeological investigations once a “development plan has been

[6] In structural geology an anticline is a fold that is convex up and has its oldest beds at its core.

finalized for the Project Site" and an "engineering and design (including the proposed depths of the linear components under consideration) have been finalized." Staff considers the current project description and data responses to provide an adequate amount of project definition to conduct a geoarchaeological study, although the proposed project has not reached final design. Accordingly, in Data Request A195, staff requested that the applicant meet with staff to discuss the data needed to complete the staff impact analysis with respect to buried archaeological resources (CEC 2012a). As of March 2013, the proposed plan is not complete and the proposed field work has not taken place. The applicant, however, has provided staff with a draft geoarchaeological work plan (URS 2013d) and is revising the plan pursuant to staff comments.

Geotechnical Field Exploration

URS conducted a subsurface geotechnical study as part of the original AFC in order to determine what kinds of foundations would be needed for the proposed HECA facility. The Amended AFC mentions the geotechnical study briefly (Hale et al. 2012:5.3-22), citing the geotechnical report from the 2009 HECA AFC. The URS study included a site reconnaissance, field exploration, and laboratory testing of selected soil samples. As part of the field exploration, five geotechnical borings were drilled using a truck-mounted, hollow-stem drill rig to depths of 61.5–101.5 feet below the existing ground surface. Detailed profiles of the sediments were drawn. (URS 2009a:14.)

The results of the geotechnical study show that the project site is immediately underlain by approximately 10 feet of fine-grained soils comprising predominantly clays and silty clays. These upper soils are further underlain by granular soils to the maximum depth explored in the borings of 100 feet below the existing ground surface. The upper clayey soils are observed to possess a medium stiff consistency, although the top half (about 5 feet) is generally soft and wet as a result of recent agricultural use. The underlying sandy soils consist of interbedded layers of sands, silty sands, and sandy silts of the Tulare Formation with varying degrees of consistencies from medium dense to very dense. Below 30 feet, the sandy soils become dense, grading denser to the maximum depth explored in the borings (100 ft). (URS 2009b:17.) An archaeologist was present during these excavations, but no archaeological materials were identified (URS 2012a:5.3-22).

Geoarchaeological Literature Review

The applicant completed a detailed review of existing geomorphological literature and a comparison with high-resolution aerial photography for the project vicinity. This study was based on previous research by (Meyer et al. 2009). It establishes a relational database of mapped soil series and landform age for the California Department of Transportation (Caltrans), Districts 6 and 9 (including Kern County) which includes mapped surface soil units, field observations, soil profile descriptions, and radiocarbon dates. This information was largely compiled from existing studies, primarily the Soil Survey Geographic (SSURGO) database. In the project vicinity, the database is a digital duplication of the original Soil Conservation Service soil survey maps (Hale et al. 2012:51).

Meyer et al.'s (2009) main assumption is that specific soil types are typically associated with particular depositional environments and landforms of a definite age. The degree of soil profile development provided by published soil series descriptions was used to make initial relative age estimates. Age estimates were also based on the geomorphic position of associated landforms, cross-cutting relationships, degree and extent of erosional dissection, radiocarbon dates, and correlation with other dated deposits. A combination of soil profile development, horizontal crosscutting relationships, and radiocarbon dating was used to place similar soil series and landforms into particular temporal groups. This cross-comparison effort resulted in SSURGO soil-map units that were associated with landforms that occupy similar geomorphic positions on the landscape. These units were then grouped into major time periods that were assigned a relative sensitivity for buried archaeological resources. The results indicate that the older the landform, the less likely it is to harbor buried archaeological deposits. (Meyer et al. 2009:123, 128.)

While the SSURGO soil maps provide a level of detail that is appropriate for a regional scale study, some specialists do not consider them to provide a useful resolution of data for the analysis of a particular project area. In fact, (Meyer et al. 2009) concludes that "depending on the nature and scope of a proposed project, areas of Moderately High through Very High potential will often require additional attention, perhaps leading to more focused geoarchaeological studies. These might include additional archival background research, field checking and examinations, subsurface explorations (e.g., trenching or coring), or more detailed modeling efforts" (Meyer et al. 2009:142). Only one landform within the project vicinity, the Quaternary alluvial fans (Qa) forming the lower elevations of the Elk Hills, has been explored at this resolution (see Weber 1998).

The applicant has not conducted the additional sub-surface sampling which staff considers necessary to complete an analysis of the potential cultural resource impacts of the proposed project. However, the applicant did supplement the SSURGO soil maps with a consideration of high-resolution aerial photography and geomorphological work associated with previous archaeological projects. There are five major landforms in the HECA project vicinity: Tulare Formation (QTt), Elk Hills Alluvial Fan (Qa), Buena Vista Slough (Qb), Kern River Alluvial Fan (Qya), and Older Alluvium (Qoa). These landforms are generally coincident with the Quaternary geology units noted on the SSURGO soil-maps by (Dale et al. 1966). These five units, their distribution in the project vicinity, their estimated age, approximate depths and sensitivity for cultural resources, are described in detail below (see **Cultural Resources Figure 1**).

QTt: Tulare Formation

This unit is present in the higher elevations of the Elk Hills along the southern end of the HECA CO_2 pipeline. The Elk Hills are formed by a structural anticline which has elevated older deposits above the surrounding valley floor and exposed them to erosion. These deposits are made up of the Tulare Formation which consists of up to 2,200 ft of interbedded, oxidized to reduced sands and gypsiferous (containing gypsum) clays and gravels derived predominantly from sources in the South Coast Ranges. Surface expressions of this unit are early to middle Pleistocene in age and have been stable or erosional since well before the first movement of humans into California (ca. 13,000 years ago). Within the study area, local portions of the Tulare Formation may be capped by younger Pleistocene deposits, such as the Elk Hills Quaternary Alluvial fans (Qa) and Buena Vista Slough (Qb) units. (Hale et al. 2012:51.)

Staff considers this stratigraphic unit to have a low to moderate potential for archaeological materials on its upper surface. Relatively high-energy alluvial and eolian movement of sediments would not be conducive to the preservation of archaeological materials and the spatial associations among them. Given the age and erosional nature of this upper portion of the Elk Hills, staff considers this stratigraphic unit to have a very low potential for intact buried archaeological deposits.

Qa: Quaternary Alluvial Fans—Elk Hills

This unit forms the lower elevations of the Elk Hills, which would be crossed by a portion of the proposed CO_2 pipeline. These multiple coalescing alluvial fans are composed of sand and gravel which were originally part of the Tulare Formation. Alluvial fan deposits can be distinguished from Buena Vista Slough deposits by their by oxidized red and yellow hues. These soils are latest Holocene in age with a potential for buried surfaces spanning most of human history in California (ca. 13,000 years ago). Elk Hills Alluvial Fan (Qa) deposits may be underlain by the Tulare Formation (QTt) and overlain by Buena Vista Slough (Qb) deposits. Geotechnical investigations conducted for the HECA Project on the lower portions of the Qa coalescing fans found that these sediments transitioned to the Tulare Formation at various depths, from approximately 8–18 ft below ground surface. (Hale et al. 2012:52–53.)

Additional geomorphic information was generated in conjunction with archaeological testing at CA-KER-3080, a prehistoric site in the Elk Hills (Weber 1998). Weber identified three major stratigraphic units within the Qa fan. The lowest level, Unit I, consists of fluvial sand and gravel eroded from the Elk Hills during a portion of the Pleistocene (100,000–40,000 years ago). This unit is overlain by Unit II, an unconsolidated, poorly sorted sandy soil deposited during the last 1,000 years and riddled with rodent burrows. Archaeological sites are frequently deposited on the surface. Unit II is overlain by Unit III, a coarse sandy soil of recent to modern age (Hale et al. 2012:53.)

Staff considers this stratigraphic unit to have a low-to-moderate potential for containing buried deposits. The potential for buried deposits is expected to increase with proximity to Buena Vista Slough. Relatively low-energy alluvial and eolian movement of sediments would be conducive to the preservation of archaeological materials and the spatial associations among them. Poorer preservation of these spatial associations is expected in sites located along the steeper slopes of Elk Hills which are characterized by higher-energy movement of water through these sediments.

Qb: Basin Deposits—Buena Vista Slough

The proposed project site, process water pipeline, electrical transmission line, part of the rail spur, and part of the natural gas line are located within this geologic unit. This Holocene-age unit was formed by progressive sedimentation of the structural syncline[7] between the Elk Hills and Buttonwillow Ridge anticlines. In the Tulare and Buena Vista basins the unit consists of silt, silty clay, sandy clay, and clay interbedded with poorly permeable sand layers. These lacustrine basin sediments are distinguished by blue

[7] In structural geology, a syncline is a downward-curving fold, with layers that dip toward the center of the structure.

hued patterns in the soil formed by the oxidation and reduction of iron and/or manganese in water-saturated conditions.

These sediments are latest Holocene in age and have a potential for paleosols[8] spanning most of human history in California (ca. 13,000 years ago). Previous research in the area suggests that Buena Vista Slough (Qb) sediments of this age can be expected up to 35 ft below the modern ground surface. Specifically, these studies have identified at least three distinct stratigraphic units within Qb sediments along the shore of Buena Vista Lake (Fredrickson 1986; Fredrickson and Grossman 1977; Wedel 1941). The deepest unit is found at depths ranging from approximately 10 to 15 ft. Archaeological deposits in this unit have been dated as approximately 8,000 years old. The middle unit is found between 5 and 10 ft deep, while the shallowest unit is found near the modern ground surface and reaches as far as 10 ft deep. Two drill sites along the Buena Vista Slough produced fossil wood at 20 and 35 ft below ground surface. Radiocarbon dating of these samples produced latest Pleistocene ages of ca. 13,500 and 14,000 ^{14}C years B.P., respectively (Manning 1968). A similar depositional environment can be expected for the western portion of the Buena Vista Slough basin deposits (Qb), which interfaces with the toe of the Elk Hills alluvial fan piedmont (Qa). (Hale et al. 2012:55–56.) This evidence suggests that buried resources may be present in this stratigraphic unit from the modern ground surface to a depth of approximately 35 ft. However, given the interfingering of geologic units and the potential for rise and dip of geologic formations, the depth of this unit may be variable and should be confirmed.

Buena Vista flood basin deposits can be difficult to distinguish from underlying fine-grained older alluvium (Qoa). Buena Vista Slough (Qb) and Alluvial fan deposits (Qa and Qya) interfinger, the result of seasonal overflows of Buena Vista Lake and the Kern River. The contact between the Elk Hills coalescing alluvial fans (Qa) and the Buena Vista Basin deposits (Qb) is generally coincident with the West Side/Kern River Flood Canal. (Hale et al. 2012:56.)

Staff considers this stratigraphic unit to have a high potential for containing buried archaeological deposits associated with human utilization of resources associated with Buena Vista Lake and Buena Vista Slough. Relatively low-energy alluvial movement of sediments would be conducive to the preservation of archaeological materials and the spatial associations among them.

Qya: Recent/Young Quaternary Alluvium—Kern River Alluvial Fan

The proposed natural gas pipeline would cross this geologic unit. The unit consists of a fine sandy loam which is part of the Kern River alluvial fan which stretches over 20 mi from the base of the Sierra foothills, across the valley, to the western terminus at the Elk Hills. This landform is latest Holocene in age and may interfinger or overlay fine-grained older alluvium (Qoa). (Hale et al. 2012:57.)

Staff considers this stratigraphic unit to have a high potential for containing buried deposits. This sensitivity is a product of the young age and actively accreting nature of the Kern River Alluvial Fan, as well as the proximity to the Buena Vista Lake outlet

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[8] A term used in geology and geoarchaeology to refer to a former soil or stable surface preserved by burial underneath either natural or cultural deposits.

channel and the distinct environmental resources provided by both the Buena Vista Slough and Lake.

Qoa: Older Alluvium

The proposed natural gas pipeline and the rail spur would cross this geologic unit. This unit is coincident with Buttonwillow Ridge (Interstate 5 [I-5] and vicinity). The ridge was likely formed by a structural anticline which has uplifted and preserved older valley deposits above the surrounding younger basin and fan deposits. This unit is largely composed of up to 250 ft of Pleistocene-age lenticular deposits of clay, silt, sand, and gravel that are loosely consolidated to cemented, and which is often indistinguishable from the Tulare Formation (QTt). The landform is latest Pleistocene to earliest Holocene in age and has been stable to slightly erosional for most of the past 13,000 years. (Hale et al. 2012:58.)

Staff considers this stratigraphic unit to have a low to moderate potential for archaeological materials on its upper surface. However, given the age and predominantly stable nature of these older valley deposits, staff considers the potential for buried archaeological deposits to be very low.

Overall, the HECA project site and proposed linear alignments are proposed to be built in deposits of Holocene age. Staff considers these deposits to have a high potential to contain well-preserved, buried cultural materials. These materials would be expected within 35 ft of the modern ground surface. Therefore, all of the HECA project's proposed ground-disturbing activities have the potential to substantially and adversely change the NRHP- and CRHR-eligibility of archaeological deposits that may lie buried in proposed construction areas. Geoarchaeological field explorations will be required in order to establish a factual basis for the assessment of potential effects to buried deposits within the project limits. Such field explorations involve excavating trenches in strategic locations across the project vicinity to observe and document subsurface conditions that affect the potential occurrence and preservation of buried archaeological resources in the area. Additionally, samples from the trenches will be obtained for radiocarbon dating and other analyses, and a report of methods and conclusions prepared.

Prehistoric Setting

Human populations have occupied the Southern San Joaquin Valley for at least 10,000 years (Moratto 1984). However, little is known about the prehistory of the region. In part, this is the result of natural processes which have buried or eroded many sites. Agricultural development and levee construction has also played a part in the destruction of the archaeological record. No single chronological framework exists for the whole valley and many are poorly defined, based on few—if any—radiocarbon dates. A basic cultural-historical outline for the Southern San Joaquin Valley was established in the early part of the twentieth century (Frederickson and Grossman 1977; Gifford and Schenk 1926; Wedel 1941). However, these early attempts were based on surface finds, limited test excavations, and small sample sizes rather than large-scale data recovery projects or regional surveys. These early studies focused on artifact and burial recovery, while ignoring dietary remains and technological features making modern reanalysis difficult, if not impossible. More recent studies in the area are characterized by reworking old data, which is problematic given the limitations described above.

Regional Chronological Sequence

The most recent synthetic discussion of the archaeology and culture-historical sequence of the Southern San Joaquin Valley is contained in (Rosenthal et al. 2007). These authors propose a variation on the chronological sequence originally established by James Bennyhoff and David Fredrickson (Hughes 1994; Moratto 1984). In this original sequence, the prehistory of the San Joaquin Valley was divided into three periods: Paleo-Indian (Early), Archaic (Middle), and Emergent (Late). The following sequence is based on this general structure, but is elaborated using recent radiocarbon dates and Hartzell's (1992) study of sites along the edge of Buena Vista Lake and Slough.

Paleo-Indian (13,550–10,550 B.P.)

The Paleo-Indian period begins with the first human occupation of California. Sites from this time period are characterized by "lanceolate bifaces, usually with an edge-ground concave base, that exhibits a large central flake scar running from the basal end up the middle of at least one face toward the tip" (Rondeau et al. 2007:64). These projectile points have a wide geographic spread and are referred to by many names including: Folsom Points, Clovis Points, and Paleo-Indian Points. At the regional level the people who made them are also referred to as Folsom and Clovis, and in California have been referred to as the "Fluted Point Tradition" (Morratto1984:79–81).

Paleo-Indian finds are rare and mostly have been found as isolated artifacts without clear stratigraphic associations, but are understood to represent the earliest occupants of the New World. The lack of information has made this period difficult to understand. Originally the first immigrants were thought to have avoided an ice covered Pacific coast. However recent research has demonstrated that the California coast was largely deglaciated by approximately 16,000 years ago and supported a diverse and productive array of plants and animals. Dates from newly excavated sites on islands off Alta and Baja California confirm that coastal sites are roughly contemporary with Paleo-Indian sites in the interior of California. On the coast, Paleo-Indians were diverse hunters and gatherers with sea-worthy boats capable of hunting sea mammals and fishing. Shellfish and other shore resources were also utilized. Paleo-Indian sites in the interior primarily date to around 10,000 years ago and are located near lakes and marshes. In contrast the economy of the interior emphasized seed collection and the use of milling stones. *Olivella* (olive snail) shell beads have also been found, indicating trade connections between the interior and the coast. (Erlandson et al. 2007.)

The earliest accepted evidence of human occupation of the San Joaquin Valley consists of basally thinned and fluted projectile points found at scattered surface locations at Tracy Lake, Woolfsen Mound (CA-MER-215), and Tulare Lake basin. The Witt site (CA-KIN-32) on a Late Pleistocene remnant shoreline of Tulare Lake is the best known. Present at this site are concave base points, and three uranium series (230^{Th}) dates from human bone ranging from 11,000 to 15,000 years ago. The bones of extinct fauna have also been found on this shoreline, but not in clear association with artifacts. (Rondeau et al. 2007:68; Rosenthal 2007:151.)

Lower Archaic (10,550–7550 B.P.)

The Paleo-Indian period or Fluted Point Tradition (Moratto1984:90–103) was followed by the Lower Archaic. The Lower Archaic has also been referred to as the “Western Pluvial Lakes Tradition” in interior California and the “Paleo-Coastal Tradition” along the coast. This time period is characterized by widespread erosion which created a clear stratigraphic boundary between the Late Pleistocene and Holocene. It is primarily represented by isolated finds of distinctive stemmed projectile points and other flaked stone tools such as stone crescents. Compared to other time periods, obsidian is relatively rare. The common occurrence of large heavily worked projectile points has led to the interpretation that hunting artiodactyls was the focus of Early Archaic economies. Interestingly, this is not supported by contemporary faunal remains. Nevertheless, milling tools are mostly absent from valley floor assemblages, but are present in foothill contexts. The relationship between valley floor and foothills sites is unclear but may have been seasonal expressions of the same adaptation.

Hartzell (1992:297) identifies this period as the Early Holocene (8000–7000 B.P.) based on her work at CA-KER-116. This site is located on the shore of Buena Vista Lake, near the proposed project. Characteristic artifacts from this site and time period include chipped stone crescents and large stemmed projectile points. In addition, two samples of freshwater mussel shell were radiocarbon dated to be approximately 9,000 years old. Isolated artifacts thought to date from this time period have also been found in the area. Stemmed projectile points were found near Tulare Lake, and *Tivela* (Pismo clam) disk beads approximately 8,000 years old were found at an Elk Hills site, CA-KER-3168 (Jackson et al. 1998; Rosenthal et al. 2007:152).

Middle Archaic (7550–2550 B.P.)

The Middle Archaic is marked by a dramatic increase in temperatures which resulted in the shrinking and complete disappearance of regional lakes. Rising ocean waters pushed inland creating the much larger Sacramento-San Joaquin River Delta. In general, this time period is associated with a shift to mortar and pestle, more intensive subsistence practices, greater residential stability, the increasing importance of fishing, basketry, simple pottery and clay objects, and the establishment of extensive exchange networks for obsidian and for olive snail shell beads. During this time there were two distinct settlement-subsistence patterns in the San Joaquin Valley: the valley floor pattern and the foothill pattern. Archaeological sites associated with the foothill pattern are common, especially in buried contexts. These sites are characterized flaked and ground stone tools used in food procurement and processing of acorns and pine nuts, tabular pendants, incised slate, and rarely perforated stone plummets. Middle Archaic projectile points include notched, stemmed, thick-leaf and narrow concave base darts. Common features found are rock filled cooking features and graves capped with cairns of rocks and milling equipment. Middle Archaic sites on the valley floor are rare, probably due to natural geomorphic changes. One of the few named components from this period is the Windmiller Pattern, which occurs mainly in the Sacramento area. These sites have evidence of year-round occupation and a distinct pattern of burial treatment which includes western orientation of ventrally or dorsally extended remains. (Rosenthal et al. 2007.)

Hartzell identifies this period as belonging to the Middle (7000–4000 B.P.) and Late Holocene (4000–2000 B.P.). Her analysis of sites along the Buena Vista Lake and Slough found a lack of sites during the Middle Holocene. This pattern may reflect changing settlement patterns in response to a variable climate (Hartzell 1992:300). The first portion of the Late Holocene, in contrast, is characterized by a return to lakeshore and slough locations, large Pinto and Elko series projectile points, extended burials, and a wider range of faunal species than utilized during the Early Holocene (Hartzell 1992:301). There are few examples of sites in the project vicinity from this time period. Only two Elk Hills sites of this age (CA-KER-3166/H and CA-KER-5404) are known to possess examples of wall-cut and grooved-rectangle olive snail shell beads which suggest that these sites have Middle Archaic components. Other sites may be buried along the local river courses. (Jackson et al. 1999.)

Upper Archaic (2550–900 B.P.)

The Upper Archaic was cooler and wetter than the Middle Archaic. The increased rainfall that gradually filled the lakes renewed fan and floodplain deposition. The archaeological record of the Upper Archaic is better represented and understood than any of the previous time periods. This period was characterized by the development of distinct sociopolitical entities, marked by contrasting burial postures and artifact styles. Subsistence practices within the delta and adjacent portions of the Sacramento and San Joaquin valleys emphasized a heavy reliance on acorns; at the margins of the valley acorns were supplemented with pine nuts. Specialized craft production became more common and expanded to include production of bone tools, shell beads, obsidian tools, and ground stone. Upper Archaic sites in the Sacramento Delta have been referred to as the Middle Horizon and the Berkeley Pattern. These sites are characterized by large mounded villages, flexed burials and a long term residential pattern which may have replaced the earlier Windmiller Pattern (Rosenthal et al. 2007:156).

Hartzell identifies this period as the second portion of the Late Holocene (2000–1000 B.P.). This period is characterized by the adoption of the bow and arrow, year-round villages at Buena Vista Lake (CA-KER-39 and CA-KER-116), a deep and highly productive lake, and faunal remains that indicate the utilization of a wide variety of species. Some of the Upper Archaic features at these sites include intact house floors and extensive dietary debris.

Emergent (900 B.P.–Historic)

The Upper Archaic was followed by the Emergent Period, which is characterized by the onset of cultural patterns similar to those existing at the time of European contact. During this time, large populous mound villages were established along river channels and sloughs. These communities invested in the construction of fish weirs and became increasingly dependent on fishing, small seeds, and plant harvesting in general over time. The local production of shell beads also became common, indicating the adoption of beads as a monetized system of exchange. Emergent Period grave offerings are characterized by shell beads, shell ornaments, and “killed” ground stone tools. Between 850 and 650 B.P. the bow and arrow replaced the atlatl. Archaeological sites from this period are more likely to have well preserved features, especially in the case of residential structures. In the Sacramento Delta this period is associated with the Augustine Pattern and in western California with the Pacheco Complex, but in general there are few named Emergent components or phases. Archaeological sites from the Emergent Period can be divided into upper and lower phases. The lower phase is distinguished by the use of banjo *Haliotis* (abalone) ornaments, incised bird bone whistles and tubes, flanged soapstone pipes, rectangular olive snail sequin beads, serrated projectile points, and cremations for high status individuals only. The upper phase is characterized by the use of small corner-notched and desert series arrow points, olive snail lipped and clam disk beads, drill beads, magnetite cylinders, hopper mortars, and the widespread use of cremation (Rosenthal et al. 2007:157–158).

Hartzell identifies this period as the third portion of the Late Holocene (1000 B.P. to Historic). This period is characterized by a decline in the use of the lake and slough, exclusively short-term occupation along the lake and slough, and environmental indicators suggesting a warm and dry trend with a receding shoreline (Hartzell 1992:311).

Previous Research: Buena Vista Basin

The region in the project vicinity has been subject to more than 100 years of archaeological inquiry. Much of this work has focused either on the exploration of the large prehistoric midden sites along the edges of Buena Vista Lake and Buena Vista Slough or on cultural resources within the Elk Hills Oil Field (EHOF), formerly the Elk Hills Naval Petroleum Reserve No. 1 (NPR-1). The following is a brief overview of this previous research, with an emphasis on work most relevant to the proposed project. The CO_2 pipelines and processing facilities planned by Occidental of Elk Hills, Inc. (OEHI), and considered part of the proposed action in this document, will take place within the EHOF. Therefore, the history of the archaeology of EHOF is also discussed.

A number of surveys and excavations were conducted in Kern County beginning as early as 1899. These were summarized and published by Gifford and Schenck (1926). Some of the earliest work was conducted by P. M. Jones in the 1890s, who directed fieldwork in the Buena Vista-Tulare Lake area. He investigated 150 prehistoric mound sites, and trenched several of these, including CA-KER-53. Nelson (in 1909) and Kroeber (in 1910) also explored sites along Buena Vista Lake. Gifford and Schenck (1926) synthesized these reports into some of the first artifact descriptions and typologies for the region. Further they defined an elaborate culture complex for the late prehistoric period, which they ascribed to the Yokuts.

One of the first full-scale archaeological excavations in the region took place in the 1930s as part of the Civil Works Administration. Strong, Wedel, and others directed 200 unemployed oil workers in the excavation of two large midden sites along the southwest edge of Buena Vista Lake. The California Project #SLF-76, Tulamniu Excavations (Wedel 1941), is considered the most comprehensive work written on the archaeology of the Southern San Joaquin Valley. This report describes in detail the focused excavations at Sites #1 and #2 (since renamed CA-KER-39 and CA-KER-60), and more limited explorations at three nearby cemeteries (sites #3–5). The excavations were conducted with an unusually high level of detail for the era. Each site was excavated using a grid, arbitrary levels, exploratory trenching, screening of all sediment, large horizontal exposures to explore residential features, and sidewall profiles. Wedel identified two distinct occupation phases with both of these sites. The earliest was characterized by manos, millingstones, hearths, and at site #2 four fully extended caliche-encrusted burials. The later occupation was characterized by asphaltum, steatite, shell beads, flexed burials, stone-filled hearths, and circular patterns of post-holes representing structures. Although the original purpose of the project was to use the direct historic approach to find a connection between the rancheria of Tulamniu mentioned in several Spanish accounts, and the archaeological record, Wedel's work never conclusively proved that sites #1 and #2 were Tulamniu. Walker (1947), in his work at a nearby cemetery site, also encountered historic period trade beads. This discovery suggested that CA-KER-64 was Tulamniu.

The next major excavation in the region took place at CA-KER-116 as part of the construction of the California Aqueduct in the 1960s. Like CA-KER-39 and CA-KER-60, this prehistoric midden is located on the southwest shore of Buena Vista Lake (Frederickson and Grossman 1977). Survey and testing by the California Department of Parks and Recreation resulted in the identification of three occupation phases. The site is particularly well known for its deepest deposit, which contains the clearest evidence of early Holocene occupation in the southern San Joaquin Valley. Material from this deposit was radiocarbon dated to 8000 B.P. and is characterized by stone crescents and large stemmed projectile points. A Late Holocene occupation, characterized by extended burials and large Pinto and Elko series projectile points, is also present at CA-KER-116. This deposit resulted in an obsidian hydration date of approximately 3000 B.P., and may be contemporary with deepest deposit at Wedel's Site #2. The third occupation is the most recent and appears to be contemporary with the upper levels of CA-KER-39 and CA-KER-60 dating to approximately 1350 B.P. The artifacts from this deposit are characterized by Cottonwood series projectile points.

Since these early projects, local researchers have continued to explore the prehistoric sites at the intersection of Buena Vista Lake and Buena Vista Slough. One of the two dissertations written about the San Joaquin Valley was focused here, and years of projects led by California State University, Bakersfield (CSUB) and the Kern Valley Archaeological Society have taken place here (Barton et al. 2010; Dieckman 1977; Hartzell 1992; Sutton 1996).

Hartzell (1992) is a reanalysis of collections and notes from CA-KER-39, CA-KER-60, and CA-KER-116 (Frederickson and Grossman 1977; Wedel 1941). She supplemented this work with a short field season to collect radiocarbon dates from Wedel's sites and to survey a portion of Buena Vista Slough in the Tule Elk State Reserve. The lakeside sites were found to have been severely damaged by looting and agricultural activities in the years since the original excavations took place. In contrast, the Reserve sites were comparatively well preserved. Multiple prehistoric sites were found on low rises next to historic slough meanders. Two of the sites in the Tule Elk Reserve, CA-KER-160 and CA-KER-1611, were further subject to testing and surface collection. Hartzell's study emphasizes faunal remains and the information they provide about prehistoric utilization of lake resources over time.

In the project vicinity, the Kern Valley Archaeological Society and CSUB have focused on salvage archaeology at the Bead Hill site (CA-KER-450). This site is another midden site on the southwest edge of Buena Vista Lake. Burials from this site contained ammunition, buttons and other historic artifacts which suggest that this site may have been the actual location of Tulamniu (Dieckman 1977; Sutton 1996). Dieckman worked at this site in the 1970s and CSUB conducted research there for most of the last decade. The results of recent research at the site suggest that the site functioned as a temporary habitation site (Barton et al. 2010), which is consistent with the settlement patterns Hartzell (1992) identified for the protohistoric period along Buena Vista Lake.

Beginning in the 1930s most of the geographic feature named the Elk Hills was owned by the US Navy and was referred to as NPR-1. In 1998 the Navy sold it to OEHI. A number of cultural resources projects took place in the Elk Hills both prior to and as part of the transfer of ownership (Farmer 1997; Hamusek-McGann et al.1997; Jackson et al 1997; Jackson et al. 1999; Parr 1996; Peak & Associates 1991). These surveys have helped characterize both the historic and prehistoric site types present within the Elk Hills, and their patterns of distribution across the landscape. NPR-1 incorporates 47,409 acres (ac). Approximately 50 percent of NPR-1 has been subject to archaeological survey and inventory of cultural resources. Sites are distributed over a wide area, but are present in the greatest density in the northern portions of NPR-1. Prehistoric sites tend to occur in geomorphic environments characterized by soil deflation; most sites had cultural remains re-deposited by eolian, alluvial and colluvial processes. Most of these sites date to the late prehistoric period (post-450 B.P.) and are characterized by sparse accumulations of artifacts and fresh water shell remains distributed over a wide area. The average site area is approximately 1.4 acres but can be in excess of 12.4 acres. Eight prehistoric sites in NPR-1 (CA-KER-3079, CA-KER-3080, CA-KER-3082, CA-KER-3085/H, CA-KER-3168, CA-KER-5373/H, CA-KER-5392, and CA-KER-5404) have been recommended as eligible for the National Register of Historic Places (Jackson et al. 1999).

Ethnographic Setting

The proposed project is located within the vast traditional territory claimed by the California Native American group known as the Yokuts. Anthropologists use this name to refer to a large and diverse group who inhabit the San Joaquin Valley and portions of the Sierra Nevada foothills of central California. The Yokuts languages belong to the Yok-Utian branch of the Penutian linguistic stock or phylum[9]. (Golla 2007:75–76; Kroeber 1976:477; Shipley 1978:89.) The Yokuts are divided into three groups based on geographical location; these groups differ significantly in their cultural patterns and dialects. The Northern Valley Yokuts are known to have occupied the area along the San Joaquin River and its tributaries, as well as west of the river, which abutted and overlapped with Costanoan and Miwok lands (Kroeber 1976:476; Milliken 1994:177, Figure 5.1; Wallace 1978a:462, Figure 1). The Foothill Yokuts are associated with the western slopes of the Sierra Nevada from the Fresno River south (Spier 1978:471, Figure 1). The Southern Valley Yokuts territory was centered near the basins of the Tulare, Buena Vista, and Kern lakes, their connecting sloughs, and the lower portions of the Kings, Kaweah, Tule, and Kern rivers (Wallace 1978b:448, Figure 1). It is the Southern Valley Yokuts that occupied the project vicinity during the ethnographic past.

[9] Linguists classify groups of languages based on linguistic similarities, using structures similar to biological classification (Driver 1961:571). Above the level of the individual language are the following groupings: sub-family, family, sub-branch, branch, and stock or phylum.

Southern Valley Yokuts

The southern group of Yokuts was made up of 16 subgroups, each speaking a different dialect of the Yokuts language. Five of the Southern Valley Yokuts subgroups are located in the project vicinity. The Tulumne (Tulamni) Yokuts occupied Buena Vista Lake, with the Yowlumne (Yawelmani) Yokuts and Tuhoumne (Chuxoxi) Yokuts living in the channels and sloughs of the Kern River Delta. The Halaumne (Hometwoli) Yokuts occupied the area surrounding Kern Lake, while the Paleumne Yokuts lived to the northeast near Kern River and Poso Creeks. (Kroeber 1976:Plate 47; Latta 1999:back cover; Wallace 1978b:Figure 1; **Cultural Resources Figure 2**.) A known village site, Telúmneu, was located near the proposed project. Located on the western shore of Buena Vista Lake, this village site was likely at the foot of the Elk Hills or just south of Buena Vista Creek (Latta 1999:back cover; Wallace 1978b:Figure 1). Another village site, Shuquoiu, known to have been located on the west side of Buena Vista Lake and the eastern tip of the Elk Hills, was situated on a trail which went around the lake, and continued north. The exact location of this village site is unknown. (Latta 1999:315.) Additionally, several archaeological investigations and illicit collectors have uncovered other villages, cemeteries, and mounds with burials in the project vicinity (see Gifford and Schenck 1926; Walker 1947; Wedel 1941).

The subgroups constituting the Southern Valley Yokuts not only maintained dialectical differences, but inhabited delineated territories wherein these groups maintained their traditional cultural patterns. Although Kroeber (1976:474) used the term “tribelet” to describe most similar California Indian communities, he believed the Yokuts to be unique in comprising true tribes, as they had their own group names corresponding to territory and language. Kroeber (1976:474) estimated that there could have been as many as 50 different Yokuts tribes throughout the San Joaquin Valley. Each tribe collectively “owned” the land from where they managed their resources, claiming an area around 250 square miles. These tribes were self-governing entities with a hereditary chief, *winatuns* (assistants to the chiefs), about 350 people, and their own name for themselves. (Kroeber 1976:474; Wallace 1978b:454.) Relationships between tribes varied; some were intimate enough with each other that they freely entered each other’s areas while other tribes were more hostile toward outsiders (Kroeber 1976:497; Wallace 1978b:454).

Tribal groups persist to this day. However, due to various historic events and federal governmental Indian policies, tribes no longer exactly represent the discrete tribal units of the ethnographic past. Seven distinct tribal governments, with varying affiliations to the project vicinity were consulted regarding the proposed project. Tribes were invited to participate based upon a list of affiliated tribes provided by the Native American Heritage Commission (NAHC). The seven invited tribal governments represent eight different cultural affiliations. From north to south, these affiliations are: Tachi (Yokuts), Tubatulabal, Yowlumne (Yokuts), Yokuts, Kawaiisu, Koso, Kitanemuk, and Southern Paiute. Information concerning specific consultation efforts is described further in this document (see “Historical Resources Inventory/Background Research/Native American Consultation”).

The remainder of this ethnographic context describes the Yokuts cultural practices in more detail. To provide comprehensive coverage of the Yokuts and to provide the reader with a succinct yet informative summary, this section will discuss the following aspects of Yokuts culture; settlement patterns, mortuary treatments, resource exploitation, and ceremonies, shamans and totems.

Settlement Patterns

Archaeological evidence indicates that humans have been present in the southern San Joaquin Valley for about 12,000 years (Rosenthal et al. 2007:151). During most of this period, they had access to vast lake and slough resources, and consequently were able to obtain most necessary resources in their immediate vicinity[10]. Therefore, these groups established relatively permanent settlements, which only needed to be moved when the lakes and sloughs rose so high that their villages became inundated with water. Village inundation happened both due to flooding from the rivers that fed the lakes, but also from high winds which could move the shoreline. Because the land surrounding the lakes in the southern valley was relatively level, even a rise or fall of 1 foot in lake level could cause the shoreline to move as much as 2 miles. Consequently, when the shoreline moved, the villages often moved along with it. (Latta 1999:245.) It was critically important that groups were located close to permanent, or at least semi-permanent water sources as the San Joaquin Valley only receives 5–10 inches of rain annually, almost all of which falls in the winter months (Wallace 1978b:448). The most favorable areas for permanent settlement were likely around Goose Lake and both ends of the Goose Lake slough, and in the southern 20–25 miles of Buena Vista Slough in the project vicinity, because these areas received an ample supply of consistent water which helped to facilitate the growth of trees (Gifford and Schenck 1926:12).

In order to avoid inundation by rising lake waters, groups often placed houses on artificial mounds. Yokuts excavated soil from low areas with digging sticks, placed it in baskets, and then piled the dirt at the desired location to make house foundations. (Latta 1999:71.) This practice was more common in the Sacramento–San Joaquin River Delta areas farther north, but it is likely that some settlements in the southern valley also maintained this practice. On some older topographic maps of the area, these locations are marked as “Indian mounds”. Latta (1999:235) believed that these residential mounds were generally separate from burial mounds, which is consistent with the prevailing Yokuts practice of burying their dead in a dedicated graveyard, although cremations are also recorded[11] (Kroeber 1976:499; Wallace 1978b:455).

After marriage, most of the Southern Valley Yokuts adhered to a patrilocal residential pattern, where the newlyweds would move into the home of the husband’s family and live there for about one year before they either established their own residence nearby, or, if all the families were living in a communal home, they would remain there (Gayton 1948:11). However, this practice was not universal among the Yokuts; some tribes are known to have followed a matrilocal residence pattern (Latta 1999).

[10] Gayton (1946:256–257) states that some groups, especially those in the foothills, left their permanent homes in the late spring/early summer and established temporary residences in areas to gather seeds and other non-local resources.

[11] Among the Tachi Yokuts the bodies of deceased people “of account” were burned (Kroeber 1976:499).

The Yokuts constructed six different types of dwellings, single family dwellings, communal houses, winter houses, bark houses, granaries and sweat houses, although only four of these, the single family house (two types), the communal house, granaries, and sweat houses, are known to have been used by those tribes in the southern San Joaquin Valley. Single-family residences were permanent year-round constructions with an oval floor plan, and tule (bulrush or cattail) mats covering the wooden framework. (Gayton 1948:11; Wallace 1978b:450–451.) Gayton (1948:13) provides a description of this type of structure:

> Two forked posts linked by a tie-beam formed the basis of this structure. Upright poles of willow were set into the ground in an oval line around the center posts and the tips pulled inward and downward and tied to the center beam. Strengthening horizontal withes were tied around this framework. Large mats of tule were hung on the frame and pegged down to the ground. A slot was left along the center beam for the smoke to escape.

Kroeber (1976:522) indicates that the center ridge pole was not always present in these smaller oval structures. Other single-family dwellings were long wedge-shaped structures, or elliptical or oblong houses with rounded vertical ends, and similarly the wooden framework was covered with tule mats (Kroeber 1976:521). Archaeological investigations of habitation sites suggest that because houses were constructed of tule and grasses, preservation of materials other than charred remains are difficult to distinguish in the archaeological record (Wedel 1941:31).

The communal house was a mat-covered gabled structure with a tule mat door and a shade porch, large enough to accommodate 10 families (Wallace 1978b:451). Gayton (1948:11) suggests that the communal house was simply an extension of the single family oval frame. Inside the communal house, tule mats partitioned sections of the house, each family having its own fireplace, and sometimes their own door (Gayton 1948:13). Generally, the house was used to store food stuffs, but granaries and separate storage structures were also built. Acorn granaries were constructed by most groups. Because there were few acorns in the valley, valley groups traded with the foothill tribes for acorns. Granaries were constructed of tule, about 3 feet across and 8–9 feet high, each family needing three to five granaries to supply them with enough acorns for the winter months. They were lined with grasses which would repel moths and squirrels, and could hold 10–30 bushels of acorns in each structure. (Latta1999:400.) Other food stuffs stored in granaries included dried fish, roots, and seeds (Wallace 1978b:451).

The sweat house was the third type of dwelling built by the Southern Valley Yokuts. This was a 15-feet oblong sudatory,[12] dug into the ground and covered with earth. The sweathouse was restricted to men, who sweated in the house daily and regularly slept there when at their home village. The sweathouse was never used for other purposes, such as a dance house or an assembly chamber, and was always located downstream from the village so as not to contaminate the water used for the village. (Kroeber 1976:521–523; Latta 1999:388; Wallace 1978b:451–453.)

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[12] Comparable to a sauna.

Other dwellings constructed by Yokuts outside of the southern San Joaquin Valley include a bark house, and a winter house made of tule, conical in shape, with a hoop at the top to attach and separate poles, leaving a smoke hole (Kroeber 1976:521). While the bark houses were not constructed in the valley itself, Kroeber (1976:522) notes that when in the hills or travelling, Yokuts made these bark houses as short-term shelters. Groups from the project vicinity travelling to the Elk Hills may have adhered to this practice. Those dwellings in the vicinity of the lake areas did not have an excavated floor so as to prevent water and moisture from coming into the house. In fact, if a house could not be constructed on a plot of land slightly higher than the surrounding area, the floor was slightly elevated by piling dirt to stay dry. Similarly, areas where people slept were also raised up, often on a willow framework (Gayton 1948:13).

The arrangement of village structures generally followed an established pattern.[13] The chief was allocated the most desirable location, often near the center of the village. The chief's assistant, the *winatun,* lived at one end of the village; if there were two, they would live at either end of the village (Kroeber 1976:497). In cases where only one winatun was present, Powers (1976:370–371) suggests that the "village captain" (likely referring to the winatun) lived at one end of the village, and a shaman lived at the other end. The houses in a village were erected in a straight line (Powers 1976:370; Wallace 1978b:451), with a permanent fire burning in the center of the village. This central fire was relatively large, usually measuring several feet across and at least 1 foot deep. If there was rain, the fire would have been placed inside a permanent house. Wedel (1941:32–33) likely found the archaeological remnants of some of these central fires, indicated by a circular charcoal bed measuring 6 feet across and 10 inches deep, with a fire pit 1 foot deep in the center of the charcoal bed and no post molds or other artifacts in the vicinity (Wedel 1941:33). Latta (1999) mentions that central fire pits were places residents would put their trash, corresponding with the large amounts of charcoal found at the central fire pit excavated by Wedel (1941:32–33). However, Hartzell (1992:178) suggests that these large charcoal beds may have been the result of ephemeral shade structures which had burned down.

As mentioned above, the sweathouse was always located downstream from the rest of the village so as not to contaminate the water, and bathing and washing were likewise performed at a downstream location (Latta 1999:388). Some villages in the valley near the lakes were constructed so that they were surrounded by tules 10–20 feet high, providing good cover against potentially hostile Europeans and Americans. In order to see those approaching the village, sun shades were constructed high enough so that one could use them as a look-out post. (Latta 1999:235.)

Villages were usually built along trails, often where two trails intersected. Trail networks connected the Yokuts to their neighbors in all directions, with whom they frequently engaged in trade. One of the most prominent trade trails in the vicinity of the project area connected the Chumash—located on the west side of the South Coast Ranges—with the Yokuts. This west-side trail skirted Buena Vista and Tulare lakes, along which the known village sites of Tulumneu and Shuquoiu were located. (Latta 1999:314–315.)

[13] One of Gayton's (1948:13) Wechihit informants (near Fresno) suggested that her tribes' villages did not adhere to any set pattern and that houses were placed in any order along the river.

Implications for the Archaeological Record Based on Settlement Patterns

As indicated by the ethnographic references above, one could expect to find a Yokuts village on land that is naturally higher than the surrounding area, or on artificially raised lands. Structures and villages could be expected to be found along lakes and sloughs, likely in a linear pattern. Lake levels in the southern San Joaquin Valley were subject to significant fluctuations, affecting the location and permanence of most settlement sites. It has been suggested that lake levels would not have risen much higher than 300 feet above mean sea level (amsl) (Gifford and Schenck 1926:15; Wedel 1941:19), and that those sites located at this elevation are likely to represent more permanent occupations. However, it should be noted that high winds could have moved the shoreline even higher than 300 feet amsl. Conversely, it should not be assumed that Yokuts occupation sites would not be found within the bounds of former lake beds, the fluctuations of which ensure that villages have been flooded in the past, the remnants now contained in sediments of the former lakes.

The Yokuts constructed various types of structures, and these structures present themselves differently in the archaeological record. One of the most significant indicators of a structure is the presence of post molds (soil discolorations resulting from decayed wood used as wall posts). These are often distinguishable in the archaeological record, and Wedel (1941:31–33) provides descriptions of houses that were excavated on the western shores of Buena Vista Lake. He states that post molds were found in sub-circular and irregularly oval shaped arrangements. One of the houses described by (Wedel 1941:31–32) contained 19 post molds, measuring 8 inches deep and 4–6 inches in diameter. These post molds were sloped inward at the top indicating the conical or domed framework suggested by the ethnographic description given by Gayton (1948:13). Within the post mold arrangement, four other post molds were identified, likely indicating the central supporting poles also described by Gayton (1948:13). A centrally located fire pit was identified, measuring 2 feet across, and relatively shallow in depth. The floor was somewhat ill-defined, but consisted of clay with about 1 foot of loose shell mixed with soil. The greatest diameter within the house was measured at 21 feet (Wedel 1941:31). Other houses identified during Wedel's investigations include a small, elliptically shaped house, 9 feet by 15 feet, and others which were more circular, not exceeding 21 feet in diameter. The post molds for these houses ranged from 2 to 8 inches across at 1–3 feet intervals. Fireplaces were located either near the center of the structure or at one side near a ring of post molds[14] (Wedel 1941:31, 84). Archaeological evidence of a communal structure was likely indicated by four ash pits in a curving line enclosed by a roughly oval double series of post molds of various sizes, and measuring about 22 feet by 25 feet with a 4-feet break at the south side, which may have indicated a door (Wedel 1941:32). Small bits of waddle-and-daub were found in association with some of the houses; however, Wedel suggests that because of the light materials used for construction, only a very thin layer of waddle-and-daub would have been practical on these dwellings (Wedel 1941:31). Moreover, the light materials used for construction of these structures are not likely to preserve well in the archaeological record, creating potential problems in discerning and correctly interpreting archaeological features.

[14] Wedel (1941:32) suggests that the fireplaces may not have been located directly next to the wall but centrally located, and only appear to be adjacent to the wall because of overlapping post molds.

It has been suggested that granaries appear in the archaeological record as indiscriminately scattered post molds (Wedel 1941:84). Identified during Wedel's archaeological investigations were clay-lined pits measuring about 16 inches in diameter respectively, about 2 inches deep and lined with 1 inch of hard greenish clay. Wedel (1941:34) suggests these may have been acorn leaching basins, but they also may have been used for storage. Cache pits were also identified, one measuring 8 inches across and 19 inches deep; it contained a pestle, steatite bowl fragments, and several stones (Wedel 1941:34).

Mortuary Treatment

Burial was the main method of treatment for the dead among those groups living in the southern San Joaquin Valley. For many of the Southern Valley Yokuts, cremation was practiced only in cases where one died away from home, or if the deceased was a shaman; however, the Tachi Yokuts cremated everybody "of account" (Kroeber 1976: 499). It has been suggested that Northern Valley Yokuts and Tachi Yokuts practiced cremation, likely because they had better access to wood than other valley groups (Gifford and Schenck 1926:50; Kroeber 1976:499; Wallace 1978b:455). Bodies were usually interred in low mounds.

The dead were handled almost exclusively by *tongochim* or *tunosim*, male transgendered individuals, although some women also were involved in the process (Gayton 1948:46; Kroeber 1976:497; Wallace 1978b:455). The *tongochim* prepared the bodies for burial by washing the body and wrapping the limbs with tule, flexing the bodies such that the knees were bent up to the torso, and hands placed to the sides of the face or temples (Gayton 1948:107; Kroeber 1976:499). The bodies were then wrapped with tule mats, or deer skins if the person was wealthy, and placed in the grave at dawn of the day following death, the morning after the second day if death occurred late the night before. The body was carried to the grave in a net by the strongest of the grave diggers who walked around the grave three times before placing the body down, and stated, "You're going where you're going, don't look back for your family"[15]. If, when the body was being interred, another burial was disturbed, the *tongochim* were required to break open the skull of the disturbed body and taste the brains to prevent themselves from dying. Once the body was placed in the ground, relatives and the *tongochim* would throw earth onto the body and then run home without looking back, for fear that the spirit would follow them home. (Gayton 1948:46, 107.)

Other than preparation of the body by flexing, there seems to have been little else that was standard practice in terms of the alignment of burials (Gifford and Schenck 1926:52). Archaeological evidence suggests that the orientation of the head of the body and the direction in which the face was aligned do not appear to have been standardized (Walker 1947:10, Table 1). Some bodies had abalone shells covering the eyes, ears and/or mouth in order that they would be able to see, hear, and talk well in Pahn Land, the Yokuts afterworld (Latta 1999:321). Pismo clam shells were sometimes placed in the mouth of the deceased so that, on the journey across the narrow bridge to Pahn Land, they would be able to pay the bad-fish people who guarded the bridge (Latta 1999:322; Wallace 1978b:456). Personal effects of the deceased were often

[15] The exact wording of this statement varied by tribe, but the general sentiment remained the same (see Kroeber 1976:509).

interred with the body, and sometimes the dog of the deceased would be sacrificed to be buried with its owner (Wallace 1978b:455). The tongochim were permitted to take possession of any of the personal effects while preparing the body (Kroeber 1976:497).

The various Yokuts tribes maintained different burial practices. There are indications that bodies were placed in separate burial grounds (Latta 1999:235), cremation generally reserved for deaths that occurred away from home (Wallace 1978b:455). The archaeological record indicates that both methods of internment were practiced (see Walker 1947 for separate burial grounds, Wedel 1941 for burials in residences). It is possible that prehistoric burials are those which were placed near residences and then burned because as Western notions of ownership and possession were acquired or forced on the Yokuts in more recent time, they would have been less likely to destroy their homes. Additionally, reduced residential opportunities as a result of Euroamerican territorial circumscription would have forced the Yokuts to be less likely to destroy their homes.

Implications for the Archaeological Record Based on Mortuary Practices

Southern Valley Yokuts practiced different types of mortuary treatments based on tribal affiliation, status of the deceased, or place of death. Both cremation and burial were practiced, and consequently both types of graves could be encountered. Burials are known to have sometimes been placed in larger cemeteries and in mounds.

Gifford and Schenck (1926:50) suggest that the soil stratification from the excavation of mounds in the project vicinity is indicative of a process wherein the body was likely placed on top of the mound and then dirt heaped over the body; however, sometimes the height of the mound was increased artificially prior to interment (Gifford and Schenck 1926:50). Because of this method, burials are usually found at the highest point of the mounds in convex rather than concave contexts, and tend to be relatively shallow and subject to bioturbation[16] (Gayton 1948:34; Gifford and Schenck 1926:37, 50). In some cases, burials have been found with cedar or juniper posts erected in the immediate vicinity (Gifford and Schenck 1926:39), notably in burials south and east of the proposed project site in the Elk Hills (Walker 1947:4). These posts are presumed to have been grave markers or supports for funeral offerings, and likely extended above the surface; however, during Walker's excavations, the posts were found 5 inches below the surface. Native Americans may have intentionally cut down the posts when the Europeans realized that the posts denoted burials and looted the graves, or the posts may have been destroyed in a brush fire. (Walker 1947:4.)

Preservation of bodies in the project vicinity tends to be poor because local soil chemistry, together with weather conditions varying from cold winter rains to intensely hot summer drought, enhances disintegration of bone. Among the hundreds of burials excavated in the Elk Hills, the remains of adults are most common, likely because greater mass and amounts of lime in the bones of adults allows for better preservation than smaller adolescent and juvenile skeletons, which contain correspondingly lower amounts of lime. Archaeological evidence suggests that bodies were usually placed lying on the side, and covered with tule mats or fabrics woven of milkweed fiber. (Walker 1947:4–5, 11).

[16] Bioturbation refers to the churning of soil by burrowing and digging animals.

Items that have been excavated with burials include broken stone bowls and other objects of steatite, fabrics made of milkweed (more common in burials with no European objects), basket fragments, varieties of shell beads (olive snail, clam, columella[17], limpet, *Saxidomus* [Washington clam], and abalone), various objects fashioned from bone and horn, gaming sticks and walnut dice, carved wooden bowls, obsidian and chert artifacts, soapstone beads, bowls, and vessels, sandstone pestles and bowls, granitic pestles and "charmstones", arrow-shaft straighteners, stone knives, scrapers, small stone "footballs", lumps of asphaltum (sometimes placed over the eyes, and sometimes made into a larger "death mask"), pebbles covered in asphaltum, various articles of clay, bear claw pendants, whistles of bird bone, and yellow and pink ochre. (Gifford and Schenck 1926:55–57; Hodgson 2004:7; Walker 1947:5–7; Wedel 1941:36, 40, 45, 48, 87.)

The presence or absence of European articles can provide relative information on when burials occurred. Glass trade beads are frequently found in burials, sometimes on strings around the neck of the bodies (Walker 1947:2, 7). European blankets were sometimes used to replace the tule mats which wrapped and covered the bodies (Gayton 1948:107). Other European objects included with burials in the project vicinity include various articles of metal (buttons, thimbles, crosses, and utensils), china, and objects of porcelain (Gifford and Schenck 1926:56; Walker 1947:7–8).

Several burials have been located in the project vicinity. A large cemetery was excavated in the Elk Hills in the 1930s. Consisting of an area about 40 feet by 50 feet, there were at least hundreds, if not thousands of burials. This cemetery contained both prehistoric and historic burials, and may have been associated with the village of *Tulamniu* (Walker 1947:2, 5). Other burials have been found near the southern end of the Buena Vista Hills, about 7 miles south of the proposed project (Wedel 1941). As indicated by the information above, burials are likely to be located on top of low lying mounds, in relatively shallow graves. Burials have also been found at house sites on the valley floor and slightly higher elevations. Because the land around the project area was one of the most ideal for permanent settlement in the southern San Joaquin Valley, it is highly probable that human remains could be inadvertently discovered during ground disturbing activities.

Resource Exploitation

The Southern Valley Yokuts maintained a mixed economy of fishing, hunting, and collecting, taking advantage of the resources at their disposal on the valley floor and surrounding areas. The lakes and sloughs of the area provided lacustrine and riparian resources such as fish, waterfowl, shellfish, roots and seeds. Acorns, the staple food of most California tribes, were not prevalent on the valley floor, so valley tribes would travel to select valley locations or the foothills to obtain them, either by trade or by collecting the nuts themselves. (Wallace 1978b:449–450.)

[17] Columella is part of a seashell, specifically the central column or axis of a spiral univalve shell, and not a species type like the other listed items. There is the dove snail (*Columbella* spp.), for which several sub species occur along the California coastline. It is not known if Walker meant to list the shell part or misspelled a species name. Other ethnographers writing about the Southern Yokuts simply list "seashells" as important cultural materials.

Tules were used for many different purposes by the Yokuts living near the lakes; they were plentiful and were used for both food and material objects. Tule roots were more often obtained by men (Gayton 1948:11) and were used to make a starchy mush or bread (Latta 1999:205; Wallace 1978b:450). Tule seeds were ground into meal, often with seeds of grasses and flowering herbs (Wallace 1978b:450). Tules were fashioned into myriad objects, including the aforementioned houses, as well as boats, mattresses, baby cradles, bags, skip rings, sunshades, windbreaks, sails on boats, clothing, mats, blankets, disposable diapers (made of pounded tule fibers), fuel, hunting blinds, baskets, shrouds, rope, and string (Latta 1999:205). Dried tules were used for firewood because of the lack of hardwoods in the valley and because willow, the most common wood in the valley, produced poor fires (Gayton 1948:16).

Fishing was a viable enterprise year-round; lake trout were the most prized fish, but chubs, greaser fish, brook trout, minnows, crayfish, mussels, clams, perch, and suckers were also taken (Gayton 1948:14; Latta 1999:248; Wallace 1978b:450). Occasionally steelhead salmon and sturgeon would enter the rivers and lakes as well. Fish were taken using nets attached to poles and drug in an arc towards the shore by men on a raft, by collective drives where the fish were herded into stick pens, or gathered by hand in nets or baskets. Gayton (1948:4–15) noted that some tribes also used a pointed harpoon with a hooked point made from a pelican wing bone to take fish, or made a poison out of a pulverized white flower to stupefy the fish. Wallace (1978b:450) also notes that turkey mullein (*Eremocarpus setigerus*), was crushed and used to stun fish; this may be the plant (white flower) referred to earlier in this paragraph. Boats made of tule were the most prevalent form of non-bipedal transportation, and a raft with a mud hearth could be used for extended fishing expeditions of three or four men for 7–10 days during times of a full moon (Latta 1999:245). Fish were usually broiled on hot coals, but in instances where a large catch was obtained, sun-drying of fish also occurred (Wallace 1978b:450).

Waterfowl and terrestrial birds were prevalent throughout the lake and slough regions in the southern San Joaquin Valley, and the Yokuts used a variety of methods to obtain them. Snares or long handled nets were used by some groups while hiding in the tules. Duck decoys, spring pole traps with underwater triggers, and boats were also used; groups would slowly pole their boats to their prey while covered with tules, and then use bows and arrows to take the waterfowl (Wallace 1978b:450). Avian species known to have been taken include geese, mudhens, swans, blue herons, egrets, pelicans, coots, grebes, ruddy ducks, mallards, stiff-tailed ducks, dabbling ducks, mergansers, and diving ducks (Hartzell 1992:185, 251, 279; Latta 1999:205).

Various mammals and aquatic reptiles were also taken. Turtles, fresh and salt water otters, beavers, raccoons, rodents, jackrabbits, cottontail rabbits, antelope, elk, ground squirrels, deer, and snakes are known to have been taken in the valley area (Hartzell 1992:184, 188, 254, 259, 280, 283; Latta 1999:229; Wallace 1978b:450). Other prey animals include dogs, which were raised to be eaten, horsefly and bee grubs, and wasp and caterpillar larvae[18] (Gayton 1948:14; Wallace 1978b:450). Smaller mammals were often taken using snares and traps or bows and arrows; larger mammals such as

[18] Wallace (1978b:450) suggests little or no insect foods were eaten, contrary to Gayton’s (1948:14) informants.

antelope and elk were not frequently pursued outside of the valley, but when these species made their way to the lake and slough areas, they were taken by the use of surrounds or snares (Latta 1999:490–491; Wallace 1978b:450). Rabbits were occasionally taken in collective drives, sometimes involving multiple tribes (Latta 1999:515). Small burrowing animals were smoked or drowned out of their burrows, or a twisted stick was used which would have been put into the burrow and then twisted, snaring the animal's fur or skin (Latta 1999:256; Wallace 1978b:450). Valley tribes stalked deer and elk. In doing so, these groups would wash themselves prior to hunting to obscure their scent, and wore deer heads in pursuit of the animals. (Latta 1999:497.) Animals which were not taken include coyotes, weasels, rattlesnakes, bats, and frogs (Gayton 1948:14; Wallace 1978b:450).

Other vegetal foods besides tules and acorns that were eaten include grass nuts (which were roasted or mashed whole into a meal), clover (popular in the spring), brodiaea bulbs, sugar (either from sugar pines or cane sugar), iris seeds, sopa seeds (possibly arrowhead), mustard greens, fiddleneck, filaree, horehound (which was cooked and the liquid drunk for relieving coughs), and salt (taken from salt grass) (Gayton 1948:14–16; Latta 1999:255; Wallace 1978b:450). Other uses for plants included smoking of tobacco in cane pipes; the tobacco, which was not cultivated or pruned, but grew wild nearby, was also often eaten or drunk. Jimsonweed was used for medicine and inducing hallucinations (Gayton 1948:16, 22, 38).

As mentioned, Yokuts tribes occupied a delineated territory of about 250 square miles. Almost all resources were obtained within this territory. Women were the primary vegetal food gatherers, and they always returned to the same areas where they obtained various seeds. Delineated by stakes placed in the ground, each seed or food gathering area encompassed about 40 square feet, and the area was passed down from mother to daughter, or sister to sister. Women felt strong ownership over these areas, and quarrels would occur if one gathered from another person's plot. Men did not have this same sense of ownership over fishing or hunting grounds, as there were not delineated areas where men consistently fished or hunted. (Gayton 1948:11.)

Yokuts material culture consisted of various types of baskets, and items crafted from steatite, granite, sandstone, bone, horn, clay, lithics, shell, and asphaltum. Baskets were used for many purposes, including cooking, gathering, storing, and fishing. Stitched together using bunchgrass (*Epicampes rigens)* as the coiled material and swamp grass (*Cladium mariscus)* for the stitching, baskets became watertight after soaking in water (Latta 1999:533). Wicker baskets were also constructed, and Yokuts used black willow or cottonwood shoots for their construction. Basketry designs generally were patterned after snakes, especially rattlesnakes, king snakes, gopher snakes, garter snakes and water snakes. Some of Latta's informants suggested that designs for baskets came to them in dreams or in jimsonweed hallucinations. (Latta 1999:547, 571, 589.)

Archaeological evidence suggests that one of the most prevalent items made from steatite were vessels, but highly polished ornaments and small beads were also common, along with arrow straighteners, tubular pipes, discs, groove-edged objects, and reel-like[19] objects (Wedel 1941:53–60, 95–97, 113–114). Granitic and sandstone objects include spheroid objects (possibly used for games), charmstones, knives, mortars, grinding stones and metates, pestles, and hammerstones. Objects fashioned from bone and horn include awls, bi-pointed objects, cut bone, horn flakers, needles, pins, sweat scrapers, tubes, whistles, and pierced fish vertebrae. (Wedel 1941:40–45, 68–72, 89–92, 100–104, 115.)

Yokuts ceramics tended to be crude and un-tempered, likely fashioned by lumping clay (Kroeber 1976:537). Baskets were a more popular form of storage and cooking than ceramics, leading to a paucity of clay objects in the archaeological record. Types of fired clay objects found in the archaeological record include beads, decorated pellets, fillets, molded circular and cylindrical objects, and pottery (Wedel 1941:45–48).

Lithics fashioned by Yokuts include objects made from chert, jasper, chalcedony, and obsidian. Obsidian was likely obtained in trade or on expeditions to the Coso Range immediately east of the southern Sierra Nevada. The stream boulders on the lower slopes of nearby mountains, possibly the Elk Hills, Lost Hills, and the South Coast Range foothills were likely the source of chert, jasper and chalcedony stone (collectively referred to as cryptocrystalline silicate rocks). Types of lithics found during archaeological investigations include projectile points, disks, gravers, knives, perforators, saws, crescentic flints, and scrapers. Projectile point types found during archaeological investigations include non-stemmed triangular points with a concave base, non-stemmed leaf-shaped points pointed at one end with a convex base, non-stemmed triangular points with a straight base, contracting stem points with no shoulders or barbs, contracting stem points with shoulders, contracting stem points with shoulders and barbs, parallel-sided stem points with no shoulders or barbs, parallel-sided stem points with shoulders and barbs, and expanding stem points with shoulders and a convex, straight or concave base. (Wedel 1941:61–68, 97–99.)

The only types of shell that were obtained locally by Yokuts were freshwater mussels and clams. However, several different types of shells were obtained in trade from coastal groups. Shells were the form of money, *chok*, used by the Yokuts prior to the arrival of Europeans, and worked shells were more valuable than whole shells. To the Yokuts, labor represented money (Latta 1999:318). Shells have been found in archaeological contexts that were fashioned into beads, ornaments, disks, and pendants (Wedel 1941:50–52). When used as money, multiple shells were strung together and their value determined by the length of the strand. The most valuable shells were Pismo clam shells, followed by keyhole limpets, abalone, periwinkle and olive snail shells. Abalone was also understood to have supernatural power, *tripne*, and consequently its use was more restricted than other types of shells. Abalone shells were often attached to ceremonial clothing, and were worn around the neck on a string in the hopes that the sun glinting off of the shell would scare away rattlesnakes; however, during thunderstorms abalone shells were not worn for fear that lightning would strike the shells. (Gayton 1948:37–38; Latta 1999:312, 320, 321.)

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[19] "Flat and usually elongate with a deep groove or notch at each end, which gives the general shape of the capital letter H" (Wedel 1941:57).

Asphaltum, or bitumen, can be found in crude surface petroleum deposits in both liquid and solid form. It is highly probable that those groups residing along the base of the Elk Hills would have obtained asphaltum in the petroleum deposits in the Elk Hills as this would have been the closest area of rich asphaltum deposits (Hodgson 2004:3–4; Wedel 1941:37). Asphaltum was used to waterproof baskets, for black paint when mixed with bear grease and elk tallow, as inlay for decorative objects, as cement for mounting scrapers, cutting tools, and projectile points, for medicinal use, as weights for women's skirts to keep the skirt hanging correctly, on Pismo clam shell money as decoration, as a material for making black smoke for smoke signals, and for securing basket hoppers to stone mortars. (Hodgson 2004:6–13; Wedel 1941:37–39.) During archaeological investigations asphaltum has been found in ball shapes and irregularly shaped lumps (which may have been the method of storing it), on pebbles coated with asphaltum (likely from being used to spread the asphaltum evenly in baskets), on a bundle of yucca fibers (which may have been used as an asphaltum brush), and on hopper mortars to hold baskets on while grinding (Wedel 1941:37–39, 88–89).

The Yokuts were "professional traders", and were the major facilitators of change in eastern and central California (Arkush 1993:620, 623). The Yokuts were located in an advantageous position for trade; they connected the groups west of the South Coast Ranges with those in the Sierra Nevada region and farther east. Generally, east–west trade trails followed major waterways (Arkush 1993:623), and at least one trail is known to have been in the project vicinity. This trail connected the South Coast Ranges to a west-side trail, which skirted Buena Vista and Tulare lakes (Latta 1999:315). Many different items were traded. The primary items the Yokuts offered for trade were asphaltum (in solid or liquid form), elk skins, deerskins, pronghorn skins, baskets, steatite, and acorn flour (Arkush 1993:622–623; Hodgson 2004:5). From the coast, the Yokuts obtained various marine shells, sea otter skins, and other marine resources. From the Sierra Nevada and immediately adjacent regions, acorns and obsidian were popular traded items, especially obsidian sourced from Inyo, Mono, Napa, and Lake counties (Latta 1999:308).

The prominent role of the Yokuts as traders facilitated their political and social complexity; however, when the Europeans arrived, many things changed. Pedro Fages, the first European known to have ventured into the valley, was the first to distribute large quantities of mass-produced European goods. Glass beads were one of the most favored European articles, and the Yokuts were responsible for much of the early historic period change into the eastern Sierra by facilitating this trade. The introduction and spread of glass beads reduced the use of shell beads and ornaments; this was a result of the popularity of glass beads, but also the missionization and destruction of coastal groups from whom the shells were obtained. Other popular European items included metal objects, blankets, and horses. In fact, the Yokuts became very fond of horse meat and frequently stole horses from the missions and ranchos in the area, eventually being referred to as the "horsethief Indians" (Arkush 1993:619–632). European items (other than horses) often were placed with the deceased in burials (Walker 1947:7–8).

Smoke signals were a form of communication used by Yokuts throughout the San Joaquin Valley. Smoke signals and fires told of strangers in Yokuts territory. Details such as the size of the party, the kind of people in the party, the direction of travel and their actions were all communicated through these smoke signals and fires. Latta estimates that it would have taken four hours for a message to reach the Cosumnes River from the lower end of the San Joaquin Valley via the South Coast Ranges and Sierra Nevada foothills (Latta 1999:338–339). Gayton (1948:9) suggests that smoke signals also were used for arranging battles between tribes. Smoke signals would have been sent from the highest area near a village, and it is likely that the Elk Hills would have been the location from where these smoke signals were sent for those villages around Buena Vista Lake and slough. Details of these smoke signals is limited, but it is known that a small, hot fire partially smothered by green weeds, green grass or asphaltum would give off sufficient signaling smoke. The fire was built in a hole in the ground, about 2 feet in diameter and 2 feet deep, and was covered with a wet *tiwon* (woman's game tray), wet blanket, wet cloth, wet tule mat, wet skin or a large cooking basket in order to catch the smoke. A long series of short puffs was the signal of an alarm, while a series of widely separated puffs gave an all-clear message. Communication at night occurred through the use of light signals. Fires were built and a blanket raised and lowered between the fire and the people with whom one was communicating provided flashing signals. (Hodgson 2004:12; Latta 1999:338–389).

In addition to trade goods, Europeans brought diseases—to which natives had no immunity—to Yokut territory. Diseases ravaged the Yokuts and evidence of mass deaths due to smallpox and malaria can be seen in burials throughout the San Joaquin Valley (Gayton 1948:9). The Spanish established several missions on the coast, and forced Native Americans to leave their homes and live at the missions. Some Native Americans escaped the missions, and the southern San Joaquin Valley became a haven for escaped mission Indians. These non-Yokuts lived among the valley Yokuts, and the Spanish, who had previously not spent much time in the San Joaquin Valley, chased down the runaway mission Indians, raiding Yokuts villages. (Wallace 1978b: 460). Some Yokuts moved their villages to riparian areas so that open-field battles with mounted soldiers could be avoided, and also built trench systems fortified by timber stockades. When non-Yokuts and Yokuts began living with each other, customs and traditions were shared, as evidenced by changes in burial practices and material objects. (Arkush 1993:630, 633).

Ceremonies, Shamans, and Totems

Several different Yokuts ceremonies have been documented, the largest being the public mourning ceremony, *lonewis*. This was a tribal-wide, sometimes with other Yokuts tribes, ceremony conducted yearly—sometimes less often—usually in summer or fall. The *lonewis*, also referred to as *lakinan*, *lakinanit*, or *tawadjnawash*, lasted for six days, and groups traveled long distances to attend. During the ceremony, groups danced, sang, and cried for the dead, and on the last day of the ceremony effigies of the deceased were burned along with other property. (Kroeber 1976:500; Latta 1999:216, 674.)

The *lonewis* was a separate ceremony from the private mourning ceremony. The private mourning ceremony was conducted by the immediate kin of the deceased, and occurred in the third month following death. During the three months of private mourning, kin cut their hair, refrained from washing their face, observed taboos against meat and salt, and secluded themselves until the ceremony. (Wallace 1978b:455–456.)

There were two types of Yokuts doctors who were called upon to heal. *Ahntru* were men or women who healed through the application of roots and herbs, although some claimed magical powers. The *tripne* or shaman was called upon after traditional medicine had failed. The shaman sang and chanted over the body in a manner which was only intelligible to him in order to drive away evil spirits, and also used burning aromatic herbs, bloodletting, pounding on the patient, and cutting and sucking out pain (Latta 1999:621). Shamans would sometimes hold ceremonies in which they demonstrated their magical skills to the tribe (Kroeber 1976:506; Wallace 1978b:456–457). There were specialized shamans as well. Some shamans were rain dancers, and they used “charmstones”, polished plumb-bob shaped stones, to induce rain. These rain-dancer shamans were less common in the valley, but American settlers employed these shamans to conduct rain-making ceremonies in order to help their crops. Other shamans were rattlesnake doctors who conducted an annual rattlesnake ceremony in the spring to overcome the supernatural power of the rattlesnakes and to insure against snake bites over the coming summer. This reverence for rattlesnakes is the reason why killing them was considered taboo. (Latta 1999:637, 639, 647, 649.) Bear shamans did not claim to cure disease, but were exhibitors of skill and had the ability to survive bear attacks. The Tachi Yokuts, however, generally attributed healing powers to bear shamans. Among other Yokuts tribes, the bear shamans did have the power to relieve symptoms, including one recorded instance of a bear shaman giving bear hair to drink during childbirth to make the labor easier. (Kroeber 1976:516–517.) Some shamans were understood to have caches of accumulated wealth, which if disturbed, resulted in swarms of insects killing the intruder (Gayton 1948:33).

Other ceremonies conducted by the Yokuts were a jimsonweed ritual for the initiation of boys, a ceremony for a girl at her first menses, and a tribal feast and dance, *haishat*, likely conducted for secular reasons. The jimsonweed ritual is unique to Penutian language-speakers[20] and was conducted either when the boy was ready, or in larger tribes annually when several boys would be initiated. Some tribes required a boy to single-handedly kill a deer before his initiation; other tribes required a chilly early morning swim in the winter. During the ceremony, boys were paired with an elder mentor, who made sure that the boy was safe during his hallucinogenic trance from drinking the jimsonweed root tea. Sometimes this mentor relationship extended beyond the initiation ceremony and lasted into adulthood. During the ceremony, men lived in the sweathouse and listened to the chief and other elders instruct them in the history and traditions of the tribe. (Gayton 1948:30; Kroeber 1976:502–507; Latta 1999:627.)

Yokuts groups adhered to a patrilineal totemic lineage; that is, the totem of a child’s father was also the totem of the child.[21] The mother’s totem was not ignored and was respected within the family. Totems were usually birds or animals, the totem of each group was revered and never intentionally killed or eaten, and the totem was regarded as a “dog” or pet (Kroeber 1976:494; Wallace 1978b:451–452). Totems were grouped into moieties, and were symbolically associated with social divisions; each moiety contained several different totemic species. Moieties were exogamous, that is, members of one moiety married outside of their own moiety, and similarly, those of the

[20] Not all Yokuts tribes practiced the jimsonweed ritual (Gayton 1948:38).

[21] Gayton (1948:28) states that in large families, sometimes the mother’s totem was passed on to one or two of the children.

same totem were not permitted to marry. (Gayton 1948:27; Kroeber 1976:493–494.) During games and ceremonies, notably the *lonewis*, moiety members were reciprocally opposed, and this opposition between totems is reflected in traditional stories which pitch totems of different moieties against each other (Gayton 1948:27; Kroeber 1976:495). Some Yokuts, and especially shamans, also respected a dream totem, an animal guide during dreams. This was sometimes the same totem as one's social totem. (Kroeber 1976:495).

The Yokuts are a culturally rich and diverse group. Their lifeways are preserved by the descendants of those Yokuts who live in the area, as well the ethnographic and archaeological records. The ethnographic record is never totally complete as long as contemporary cultures are there to provide information. It is hoped that through additional consultation efforts this ethnographic context will be expanded and clarified to better understand the potential impacts of the proposed project on cultural resources.

Historic Background

The major themes related to the historic period include Spanish explorations, the Mission period, pioneer development and ranching, water projects in the San Joaquin valley, transportation, and development of the EHOF. Spanish explorations in the project region began with the travels of Pedro Fages in 1773 and Father Francisco Garces in 1776, followed by the two expeditions in 1806 by Father Antonio Zalvidea and Lieutenant Moraga in search of mission locations. Fages visited at least one Yokuts village on the shore of Buena Vista Lake. No missions were established, and some of the subsequent expeditions between 1808 and the 1820s were conducted to capture Indians who had fled from missions. These efforts would have left little physical evidence in the region.

Pioneer Settlement and Ranching

Visits by European explorers increased in the early 1800s, but the southern San Joaquin Valley remained relatively sparsely settled for some time. Beginning in the 1830s, toward the end of the Spanish period and into the Mexican period, large tracts of land were granted to Mexican and other European settlers and used primarily for cattle grazing in support of the trade for hides and tallow. Although such Kern County ranchos as El Tejon and San Emigdio employed some of the mission Indians, they were still beset by cattle and horse raids from the nearby native communities. The most profound effect on the environment was the replacement of native vegetation by exotic grasses and forbs introduced by the new animals. Culturally, there ensued severe disruption of the Native American populations (Nachmanoff et al. 1999).

The first waves of pioneer settlement and population growth, which took place elsewhere in California after the mid-nineteenth century, largely bypassed this part of the San Joaquin Valley because of the unfavorable climate and lack of timber and potable water. Hispanic Californios carried on small-scale cattle and sheep ranching and horse trading on the west side of the valley, joined by some Basque and Portuguese herders. The first private landowner in the Elk Hills was Alice J. Miller (or Muller) in 1905, and by 1910, nearly all of the Elk Hills, not owned by the government, had been claimed (Nachmanoff et al. 1999).

Agricultural Development and Water Conveyance Systems

As the old Mexican land grants and small holdings were gradually aggregated into major ranches, such as the Miller & Lux Land Company of the 1850s, which ultimately acquired 700,000 acres, irrigation canal projects proliferated and conflicting claims to Kern River water were only settled by the California Supreme Court in 1886. Miller & Lux acquired the Kern Valley Water Company (KVWC), leader in irrigation projects in the southern San Joaquin Valley through the 1920s. The Miller & Lux system of canals later was absorbed into the Buena Vista Water Storage District (**Cultural Resources Figure 3**). After that time, the large-scale development of more efficient hydroelectric power made it economically feasible to pump groundwater for irrigation, contributing to greater expansion of farm production.

Transportation

Since prehistoric times, the Valley has served as a route of travel and trade for Native Americans, fur traders, ox cart and wagon roads (El Camino Viejo, the Old Los Angeles Trace or Old West Side Road), and parallel paths for the Stockton-Visalia and Butterfield overland stages. Construction of the Southern Pacific Railroad along the east side of the Valley in 1877 led to expansions in wheat farming and ranching, and in 1893, the Southern Pacific opened a branch line through the Elk Hills from Bakersfield to Asphalto (now McKittrick) to serve the growing asphalt industry there (Nachmanoff et al. 1999). These transportation improvements facilitated industrial growth and prosperity, expanded markets for the local products, brought about a population increase of 45 percent between 1900 and 1930, and stimulated interest in the exploration for oil.

Oil Discovery

Petroleum extraction in the region had begun with the Buena Vista Petroleum Company's refinery north of McKittrick in the 1860s, but the cost of transportation at the time made this a minor effort. The railroad, coupled with major discoveries in the McKittrick, Sunset, Kern River, and Elk Hills oil fields in the early 1900s, led to a rush to develop oil fields on the west side of the valley. Three companies acquired control of the resource and refineries: Standard Oil, Southern Pacific, and the cooperative called Associated Oil.

The Dust Bowl Migration

One of the most notable migrations to California occurred during the 1930s and 1940s when over one million people living in the Southern Plains states of Oklahoma, Texas, Missouri and Arkansas travelled to California in their search for work during the Great Depression (Gregory 1989:xiv). Already by the mid-1920s these "Southwesterners", as they were sometimes referred to, had begun migrating to the San Joaquin Valley primarily to work in the agricultural industry that was so prevalent there.

The San Joaquin Valley was a natural draw to which Southwesterners would wish to relocate. The economic focus on the oil and agricultural industries, primarily cotton, closely mirrored the prevalent industries in the Southwest, especially in the panhandles of Texas and Oklahoma. With family members already established in the region (by the 1930s at least half of the Southwestern migrants had family in California) and stories of a plethora of work in California reaching their ears, it was only a matter of time before

Southwesterners would migrate in larger numbers as their economic and physical situations in their home states deteriorated (Gregory 1989:28, 40).

The migrants came from a region that had been subject to extreme drought and over-farming, a combination that resulted in massive dust storms which swept over the plains. Referred to as the “Dust Bowl”, these environmental effects made it practically impossible to conduct agriculture in the most heavily hit areas (the Oklahoma and Texas panhandles, eastern Colorado and Kansas). The impact of the dust storms was only exacerbated by the Great Depression. California was seen as the only option for some of these people.

Once the Southwesterners arrived in California they quickly found out that work was not as easy to come by as the stories their friends and family had relayed to them made it seem. For those migrants without established family in California, living situations were very poor. Most migrants lived in squatter’s camps on the outside of cities, camped along irrigation ditches, or were lucky enough to have housing on the farm on which they worked. The government began constructing 13 Farm Security Administration camps in the mid-1930s (the closest one located to the proposed project site was located south of Bakersfield), camps which were designed to be more sanitary and comfortable than road-side housing.

The Southwesterners were slow to be absorbed into the social fabric of California, especially in the San Joaquin Valley. Because they lived in camps on the outskirts of town, referred to as “Okievilles” or “Little Oklahomas”, they were physically separated from the local populations, and the “plain-folk Americanism” culture they brought from the Southwest was not well received by many in the local populations (Gregory 1989:72, 141).

Often called “Okies” or “Arkies” by local Californians, the migrants were surprised that they were subject to discrimination that had heretofore been saved for minority groups (Stein 1979:60). As the Southwesterners continued to live in these regions, their cultural influences became more and more a part of the local community. Country music, saloons, and churches which reflected Southwestern cultural elements eventually came to be accepted institutions in the San Joaquin Valley by the 1940s (Gregory 1989:142).

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

Regulatory Context

California Environmental Quality Act

Various laws apply to the evaluation and treatment of cultural resources. CEQA requires the Energy Commission to evaluate resources by determining whether they meet several sets of specified criteria. These evaluations then influence the analysis of potential impacts to the resources and the mitigation that may be required to ameliorate any such impacts.

CEQA and the State CEQA Guidelines define significant cultural resources under two regulatory definitions: historical resources and unique archaeological resources. A historical resource is defined as a "resource listed in, or determined to be eligible by the State Historical Resources Commission, for listing in the CRHR", or "a resource listed in a local register of historical resources or identified as significant in a historical resource survey meeting the requirements of Section 5024.1 (g) of the Public Resources Code," or "any object , building, structure, site, area, place, record, or manuscript which a lead agency determines to be historically significant or significant in the architectural, engineering, scientific, economic, agricultural, educational, social, political, military, or cultural annals of California, provided the agency's determination is supported by substantial evidence in light of the whole record." (14 Cal. Code Regs., §15064.5[a].) Historical resources that are automatically listed in the CRHR include California historical resources listed in or formally determined eligible for the NRHP and California Registered Historical Landmarks from No. 770 onward (Pub. Resources Code, §5024.1[d]).

Under CEQA, a resource is generally considered to be historically significant if it meets the criteria for listing in the CRHR. These criteria are essentially the same as the eligibility criteria for the NRHP. In addition to being at least 50 years old,[22] a resource must meet at least one (and may meet more than one) of the following four criteria (14 Calif. Code Regs., §15064.5[a][3]):

- Criterion 1, is associated with events that have made a significant contribution to the broad patterns of California's history and cultural heritage;
- Criterion 2, is associated with the lives of persons significant in our past;
- Criterion 3, embodies the distinctive characteristics of a type, period, region, or method of construction, or represents the work of an important creative person, or possesses high artistic values; or
- Criterion 4, has yielded, or may be likely to yield, information important in prehistory or history.

In addition, historical resources must also possess integrity of location, design, setting, materials, workmanship, feeling, and association (14 Cal. Code Regs., §4852[c]).

Even if a resource is not listed or determined to be eligible for listing in the CRHR, CEQA allows the lead agency to make a determination as to whether the resource is a historical resource as defined in Public Resources Code, sections 5020.1(j) or 5024.1.

In addition to historical resources, archaeological artifacts, objects, or sites can meet CEQA's definition of a unique archaeological resource, even if it does not qualify as a historical resource (14 Cal. Code Regs., §15064.5[c][3]). Archaeological artifacts, objects, or sites are considered unique archaeological resources if "it can be clearly demonstrated that, without merely adding to the current body of knowledge, there is a high probability that it meets any of the following criteria:

[22] The Office of Historic Preservation (OHP 1995:2) endorses recording and evaluating resources over 45 years of age to accommodate a five-year lag in the planning process.

1. Contains information needed to answer important scientific research questions and that there is a demonstrable public interest in that information.
2. Has a special and particular quality such as being the oldest of its type or the best available example of its type.
3. Is directly associated with a scientifically recognized important prehistoric or historic event or person." (Pub. Resources Code, §21083.2[g].)

To determine whether a proposed project may have a significant effect on the [cultural resources] environment, staff analyzes the proposed project's potential to cause a substantial adverse change in the significance of historical or unique archaeological resources. The significance of an impact depends on:

- The cultural resource affected;
- The nature of the resource's historical significance;
- How the resource's historical significance is manifested physically and perceptually;
- Appraisals of those aspects of the resource's integrity that figure importantly in the manifestation of the resource's historical significance; and
- How much the impact will change those integrity appraisals.

At Title 14, California Code of Regulations, section 15064.5(b), the State CEQA Guidelines define a substantial adverse change as "physical demolition, destruction, relocation or alteration of the resource or its immediate surroundings such that the significance of an historical resource would be materially impaired".

Section 106 of the National Historic Preservation Act

The NHPA of 1966 authorized the creation of the NRHP, which contains the federal government's list of buildings, structures, objects, sites, and districts that it considers significant in American history, architecture, engineering, archaeology, and culture (16 U.S.C., §470[a][1][A]). Properties eligible for inclusion in the NRHP must meet one or more of the significance criteria defined below:

- Criterion A: Properties associated with events that have made a significant contribution to the broad patterns of American history.
- Criterion B: Properties associated with persons significant in the American past.
- Criterion C: Properties that embody distinctive characteristics of a type, period, or method of construction, or are the work of a master, or possess high artistic values, or represents a significant and distinguishable entity whose components may lack individual distinction.
- Properties that yield or may yield information important in prehistory or history. (36 C.F.R., §60.4.)

In addition to meeting one of the criteria listed above, a property must retain historical integrity. The NRHP assesses seven aspects of historical integrity:

- Location: The place where the historic property was constructed or the place where the historic event occurred.

- Design: The combination of elements that create the form, plan, space, structure, and style of a property.
- Materials: The physical elements that were combined or deposited during a particular period of time and in a particular pattern or configuration to form a historic property.
- Workmanship: The physical evidence of the crafts of a particular culture of people during any given period in history or prehistory.
- Setting: The physical environment of a historic property.
- Feeling: A property's expression of the aesthetic or historic sense of a particular period of time.
- Association: The direct link between an important historic event or person and a historic property. (36 C.F.R., §60.4.)

It is unnecessary for a property to retain all seven aspects of integrity, but a property must retain those essential aspects that convey its significance. When the integrity of a property is being evaluated, the property should also be compared with similar properties. Such comparisons may be important for determining the physical features that are essential for conveying the historical significance of a property. (Little et al. 2000:35–36).

Definition of Direct and Indirect Impacts

In the abstract, direct impacts to cultural resources are those associated with project development, construction, and co-existence. Construction usually entails surface and subsurface disturbance of the ground, and direct impacts to archaeological resources may result from the immediate disturbance of the deposits, whether from vegetation removal, vehicle travel over the surface, earth-moving activities, excavation, or demolition of overlying structures. Construction can have direct impacts on historic standing structures when those structures must be removed to make way for new structures or when the vibrations of construction impair the stability of historic structures nearby. New structures can have direct impacts on historic structures when the new structures are stylistically incompatible with their neighbors and the setting, and when the new structures produce something harmful to the materials or structural integrity of the historic structures, such as emissions or vibrations.

Generally speaking, indirect impacts to archaeological resources are those which may result from increased erosion due to site clearance and preparation, or from inadvertent damage or outright vandalism to exposed resource components due to improved accessibility. Similarly, historic structures can suffer indirect impacts when project construction creates improved accessibility and vandalism or greater weather exposure becomes possible.

Ground disturbance accompanying construction at a proposed plant site, along proposed linear facilities, and related facilities has the potential to directly impact archaeological resources, unidentified at this time. The potential direct, physical impacts of the proposed construction on unknown archaeological resources are commensurate with the extent of ground disturbance entailed in the particular mode of construction.

This varies with each component of the proposed project. Placing the proposed plant into this particular setting could have a direct impact on the integrity of association, setting, and feeling of nearby standing historic structures.

Historical Resources Inventory

The development of the inventory of historical resources in and near the proposed project area is the requisite first step in the assessment of whether the project may, under Public Resources Code, section 21084.1, cause a substantial adverse change in the significance of a historical resource, and may, therefore, have a significant effect on the environment. The effort to develop the inventory has involved conducting a sequence of investigatory phases that includes doing background research, consulting with local Native American communities, conducting primary field research, interpreting the results of the inventory effort, as a whole, and evaluating whether found cultural resources are historically significant. This section discusses the methods and the results of each inventory phase, develops the historical resources inventory for the analysis of the proposed project, and interprets the inventory to assess how well it represents the archaeology of the project area of analysis.

Project Area of Analysis and Area of Potential Effects

The project area of analysis (PAA) is a concept that staff uses to define the geographic area in which a proposed project has the potential to affect cultural resources. The effects that a project may have on cultural resources may be immediate, further removed in time, or cumulative. They may be physical, visual, auditory, or olfactory in character. The geographic area that would encompass consideration of all such effects may or may not be one uninterrupted expanse. It may include the project area, which would be the site of the proposed plant (project site), the routes of requisite transmission lines and water and natural gas pipelines, and other offsite ancillary facilities, in addition to one or several discontiguous areas where the project could be argued to potentially affect cultural resources.

Federal agencies use an identical concept, termed the “area of potential effects” (APE), to account for the effects that federal undertakings might have on historic properties, or significant cultural resources (36 C.F.R., §§800.4[1], 800.16[d]). Staff has defined the PAA in coordination with DOE. The DOE plans to use staff’s PAA as the basis for their APE when consulting under Section 106 of the NHPA. Throughout this PSA/DEIS, the PAA and APE are discussed as a single entity, the PAA/APE.

Staff presently define the PAA/APE as containing the proposed project site, controlled area, natural gas pipeline, railroad spur alignment, railroad laydown yard, process water pipeline, electrical transmission line, potable water line and well field, natural gas meter/valve station, CO_2 pipeline, and horizontal directional drilling (HDD) entry/exit pits (see URS 2012a:1-1–1-3, 2-11, 2-17, 2-19, Figures 2-4, 2-7, 2-8; URS 2012a:Appendix. C[23], Figures 2-4, 2-7, 2-8 [sheets 4–7]; Pozzuto 2012a:2, Area Map, Historic Architecture Area of Potential Effects, Archaeological Area of Potential Effects; Stantec 2012a:1.0-1, 1.0-4, 1.0-5, 3.0-1 through 3.0-13, Figure 4.1-1; Stantec 2012b:Figures 2A, 2B). The PAA/APE also includes the future switchyard to which the 230-kV electrical

[23] Confidential Appendix to the Amended AFC: Railroad and Natural Gas Linears.

transmission line would be connected. See **Cultural Resources Figure 4** for an overview of the PAA/APE. **Cultural Resources Figures 5a–5k** shows the PAA/APE in detail.

Staff also includes in the PAA/APE four intersection improvement areas, which the Amended Application for Certification (Amended AFC) identifies as needing improvements to mitigate traffic impacts (URS 2012a:5.10-19, 5.10-20). Additionally, the PAA/APE includes the proposed EOR infrastructure within the EHOF. This infrastructure includes the CO_2 processing facility, about 562 miles of above- and below-ground pipelines (oil producing lines, injection lines, gathering lines, CO_2 trunk line, oil lines, natural gas lines, water lines, fuel gas lines residue gas line, nitrogen line, and propane line), about 570 well work-overs (conversion of existing wells to EOR), about 150 new wells, and 13 satellite gathering stations (Pozzuto 2012a:2, Area Map, Historic Architecture Area of Potential Effects, Archaeological Area of Potential Effects; Stantec 2012a:1.0-7, 1.0-8, 3.0-1 through 3.0-10, Figure 4.1-1).

The PAA/APE consists of archaeological and historic built environment components (**Cultural Resources Figures 5a–k**). The archaeological components of the PAA/APE consist of the proposed footprint of the facilities listed in the previous three paragraphs. In addition, the archaeological PAA/APE includes buffers surrounding all of these proposed facilities in accordance with the Energy Commission's Siting Regulations (20 Cal. Code Regs., §1704(b)(2), App. B[g][2][C]). These buffers permit staff to account for the possibility of additional staging and laydown areas as well as minor project design changes. Staff includes a 200-feet buffer around the following proposed project features:

- Project site
- Controlled area
- Railroad laydown yard
- Natural gas meter/valve station
- HDD entry/exit pits
- CO_2 processing facility
- Water wells (well field serves as the buffer)
- Satellite gathering stations
- 150 well sites (work-overs and new well pads)
- Intersection improvement areas
- Electrical switching station

Also consistent with Title 20, California Code of Regulations, section 1704, Appendix B(g)(2)(C), staff includes a 50-feet buffer surrounding the following project elements:

- Process water line
- Natural gas pipeline
- Potable water line

- Electrical transmission line
- Railroad spur
- CO_2 pipeline from the project site to the CO_2 processing facility
- above- and below-ground pipelines in the EHOF:
    - oil producing lines
    - injection lines
    - gathering lines
    - CO_2 trunk line
    - oil lines
    - natural gas lines
    - water lines
    - fuel gas lines
    - residue gas line
    - nitrogen line
    - propane line

The depth of excavation required for construction varies among the project elements (**Cultural Resources Table 2**). The depths of excavation tabulated below present the vertical or subsurface component of the PAA/APE.

Cultural Resources Table 2
Depth of Excavation by Project Element

Project Element	Maximum Depth of Excavation[1]	References
HECA Project Elements		
Project site	5–50 ft—grading 6 ft—structural foundations	URS 2012d:A150-1
Controlled area	2.5 ft	URS 2012b:A89-1, A89-2
Railroad laydown area	Surficial	
Railroad spur	0.5–3.0 ft	URS 2012d:A150-1
Natural gas meter/valve station	6 ft (100-ft-by-100-ft footprint)	URS 2012a:2-61, 2012d:A150-2
Natural gas pipeline (12-inch diameter)	7 ft (13-mi-long, 50-ft-wide corridor)	URS 2012a:2-61, Table 2-1; URS 2012d:A150-1
HDD entry/exit pits	Up to 50–100 ft (100-ft-by-200-ft footprint)	URS 2012a:2-64, 2-65
Process water line	5 ft (within 15-mi-long, 50-ft-wide corridor)	URS 2012a:5.3-27, Table 2-1
Water wells	300–400 ft (100-ft-by-150-ft footprint)	URS 2012a:5.9-13
Potable water line	6 ft (within 1-mi-long, 10-ft-wide corridor)	URS 2012a:2-62, Table 2-1; URS 2012d:A150-2
Electrical transmission line	28 ft (26 tubular steel poles, 6-ft diameter within 2-mi-long, 100-ft-wide permanent right of way [ROW]); turning towers will be drilled 35 ft deep	URS 2012a:2-61, 5.9-14, 5.15-1; URS 2012d:A150-2; Western 2012

Project Element	Maximum Depth of Excavation[1]	References
Electrical switching station	9 ft (4-ac footprint)	URS 2013a:2-2
CO_2 pipeline	6 ft (3-mi-long, 150-ft corridor)	Stantec 2012b:Figures 2A, 2B; URS 2009b:72-1; URS 2012a:2-64
Intersection improvement areas	Unknown	
EOR Project Elements		
CO_2 processing facility	6 ft—structural foundations; up to 50 ft grading in some areas (<61-ac footprint)	Stantec 2012a:Table 3-3; URS 2012d:A150-1
Satellite gathering stations	10 ft—structural foundations (1-ac footprint)	URS 2009a:19, 26; URS 2013e:1-1
Well sites (work-overs)	Variable	
Well sites (new wells)	Variable (130-ft-by-280-ft footprint)	Stantec 2012a:Table 3-3
Oil producing lines	Surface	Stantec 2012a:Table 3-2
Injection lines, 16-inch	Surface	Stantec 2012a:Table 3-2
Injection lines, 12-inch	Surface/4–7 ft (47-ft ROW)	Stantec 2012a:Tables 3-2, 3-3; URS 2009b:67-1, 72-1
Injection lines, 10-inch	Surface	Stantec 2012a:Table 3-2
Injection lines, 6-inch	4.5–6.5 ft (59-ft ROW)	Stantec 2012a:Table 3-3; URS 2009b:67-1, 72-1
Injection lines, 4-inch	4.3–6.3 ft (40-ft ROW)	Stantec 2012a:Table 3-3; URS 2009b:67-1, 72-1
Gathering lines, 26-inch	6.2–8.2 ft (59-ft ROW)	Stantec 2012a:Tables 3-2, 3-3; URS 2009b:67-1, 72-1
Gathering lines, 18-inch	5.5–7.5 ft (59-ft ROW)	Stantec 2012a:Tables 3-2, 3-3; URS 2009b:67-1, 72-1
Gathering lines, 16-inch	Surface/5.3–7.3 ft (47-ft ROW)	Stantec 2012a:Tables 3-2, 3-3; URS 2009b:67-1, 72-1
Gathering lines, 12-inch	Surface	Stantec 2012a:Table 3-2
Gathering lines, 10-inch	Surface	Stantec 2012a:Table 3-2
CO_2 trunk line, 12-inch	4–7 ft (47-ft ROW)	Stantec 2012a:Tables 3-2, 3-3
CO_2 trunk line, 6-inch	4.5–6.5 ft (59-ft ROW)	Stantec 2012a:Tables 3-2, 3-3
CO_2 trunk line, 4-inch	4.3–6.3 ft (40-ft ROW)	Stantec 2012a:Tables 3-2, 3-3
Oil tie-in lines, 8-inch	Surface	Stantec 2012a:Table 3-2
Natural gas lines, 3-inch	Surface	Stantec 2012a:Table 3-2
Water lines, laterals, 10-inch	Surface	Stantec 2012a:Table 3-2
Fuel gas lines, 6-inch	Surface	Stantec 2012a:Table 3-2
Residue gas line, 6-inch	Surface	Stantec 2012a:Table 3-2
Nitrogen line, 8-inch	Surface	Stantec 2012a:Table 3-2
Propane line	Unknown	

Notes: 1. Depth below current ground surface. Abbreviations: ac = acre(s); ft = foot/feet

Background Research

The background research for the present analysis employs information that the applicant and staff gathered from literature and record searches, and information that the DOE and staff obtained as a result of consultation with local Native American communities. The purpose of the background information is to help formulate the initial cultural resources inventory for the present analysis, to identify information gaps, and to inform the design and the interpretation of the field research that will serve to complete the inventory.

Literature and Records Search

The literature and records search portion of the background research attempts to gather and interpret documentary evidence of the known cultural resources in the project area of analysis. The source for the present search was the Southern San Joaquin Valley Information Center (SSJVIC) of the California Historical Resources Information System (CHRIS).

CHRIS Search

Methods

URS, the cultural resources consultant to the applicant, requested records searches from the SSJVIC for several iterations of the proposed project on the following dates: in 2008 (three records searches on undisclosed dates), February 11 and 19, 2009 (RS # 09-019, 09-056). URS cultural resources staff also conducted supplemental records searches at the SSJVIC on January 12 and February 13, 2012 (RS #09-056). The 2008 and 2009 records searches covered the then-proposed project area and a 1-mile radius surrounding the project area. The 2012 records searches covered the project area and a 1-mile radius surrounding it, as well as a 0.5-mile radius from the linear project elements. The 2008 records searches comprised examinations of the SSJVIC's base maps of previous cultural resources studies and known cultural resources, as well as the following sources:

- NRHP listings.
- The Office of Historic Preservation's (OHP) Archeological Determinations of Eligibility (2006 and 2012 listings).
- OHP Directory of Historic Properties (2006, October 10, 2008, February 4, 2009, and 2012 listings).
- California State Historical Landmarks listings (1988 listings).
- CRHR listings.
- California Inventory of Historic Resources listings.
- Five Views: An Ethnic Sites Survey for California (OHP 1988).
- California Points of Historical Interest listings (1988 listings). (Farmer 2008:2-8; Hale and Laurie 2009:H3-27; Hale et al. 2012:G-3-25; HEI, with URS 2008:5.3-12; URS 2009c:5.3-18, 5.3-19; URS 2010; URS 2012a:5.3-19; URS 2013a:3-5).

At the request of Stantec Consulting Corporation, SSJVIC staff conducted a records search of the proposed CO_2 pipeline south of the California Aqueduct to the proposed CO_2 processing facility on February 21, 2011 (RS # 11-057). The records search covered the project area and a 0.5-mile radius. In conducting the records search, SSJVIC staff consulted their base maps of previous cultural resources studies and known cultural resources in the records search area. The SSJVIC also consulted the following sources of information:

- NRHP listings.
- Historic Property Data File listings (October 5, 2010).

- California State Historical Landmarks listings.
- CRHR listings.
- California Inventory of Historic Resources listings.
- California Points of Historical Interest listings. (Stantec 2011:2, Appendix A.)

OEHI's cultural resources consultant, Stantec Corporation, has completed a cultural resources inventory of the defined EOR components of the proposed HECA project. The reporting and other documentation associated with this work, however, was not submitted to the Energy Commission in time for incorporation into this PSA/DEIS. According to OEHI staff, the study has been completed, but staff has not yet received the resulting inventory report or the records search results. Staff will discuss Stantec's cultural resources inventory and findings in the Final Staff Assessment/Final Environmental Impact Statement (FSA/FEIS).

Results

The SSJVIC records searches found that 66 investigations have been wholly or partially conducted in the records search area (**Cultural Resources Table 3**).

Cultural Resources Table 3
Previous Cultural Resources Investigations in the Records Search Area

IC Report Number	Citation	Report Title	Survey Type	PAA/APE
KE-00065	Osborne 1995	Negative Archaeological Survey Report for Seismic Retrofit of Bridges 50-0307R and 50-0307L	Linear	Natural gas line
KE-00142	Pruett et al. 1997	Addendum I, Emergency Flood Area: A Cultural Resources Assessment and Plan for the Kern Water Bank Authority Project near Bakersfield, Kern County, California	Linear	Transmission and potable water lines; near project site, controlled area
KE-00156	Farmer 1997	Phase I Cultural Resources Assessment of 53 SOZ SO2 Wells Eastern Elk Hills, Naval Petroleum Reserve No. 1 Well abandonment Project Kern County, California	Record Search	EOR pipeline and EOR oil field
KE-00232		Information pending OEHI's cultural report		Near EOR oil field
KE-00233	Parr 1997	Cultural Resource Assessment of a Surface Waste Dump Locus Located North of Archaeological Site CA-KER-5060 in Section 25, T.30S., R.24E., MDBM, NPR-1	Site evaluation	Near EOR oil field
KE-00403	Fredrickson 1985	West Coast Cogeneration Project: Belridge	Linear	Process water line
KE-00419	Garcia 1993	Archaeological Assessment of Three Proposed Powerline Routes on the Elk Hills Naval Petroleum Reserve No. 1 near Taft, Kern County, California	Linear	Near EOR oil field and State Route (SR) 119 intersection improvements

IC Report Number	Citation	Report Title	Survey Type	PAA/APE
KE-00435	Clewlow 1974	Assessment of Potential Impact upon Archaeological Resources of Construction of Proposed Kern River-California Aqueduct Intertie Project by the United States Army, Corps of Engineers	Linear	Near SR 119 intersection improvements
KE-00513	Jackson 1990	Archaeological Assessments for Two Pipeline Corridors, City of Tupman, Kern County, California	Linear	Near SR 119 intersection improvements
KE-00578	Levulett 1982	Archaeological Survey Report for the Proposed Buena Vista Slough Bridge Replacement 06-Ker-58 P.M. 24.0 1 Bridge 50-03 06200-225500	Linear	Process water line
KE-00650	McManus n.d.	Archaeological Survey Report for Proposed Widening Project	Linear	SR 119 intersection improvements
KE-00714	Noble 1987	Negative Archeological Survey Report, SR 58	Linear	Natural gas line, railroad spur
KE-00751	O'Connor 1981	Archaeological Survey Report, SR 58	Linear	Process water line
KE-00755		Information pending OEHI's cultural report		Near EOR oil field, CO_2 line
KE-00759		Information pending OEHI's cultural report		EOR oil field
KE-00865		Information pending OEHI's cultural report		EOR oil field
KE-00866	Parr and Osborne 1992	Archaeological Survey Report for the Proposed Route Adoption Study on Highway 58, Bakersfield, Kern County, California	Linear	Natural gas line, SR 43 intersection improvements, transmission line
KE-00924	Peak & Associates 1991	Cultural Resource Assessment of Sample Areas of Naval Petroleum Reserve No. 1, Kern County, California	Block	CO_2 line, EOR facilities
KE-00924	Peak & Associates and EG&G Energy Measurements 1991	Research Plan for Cultural Resource Inventory of Naval Petroleum Reserve No. 1, Kern County	Research design	CO_2 line, EOR facilities
KE-01089	Schiffman and Monday 1982	Archaeological Evaluation for the Proposed Belridge Field Cogeneration Plant Kern County, California	Linear	Process water line
KE-01098	Schiffman 1984	Archaeological Investigation of Proposed Project Site Assessor's Parcel Number 103-080-6 and 07 Kern County, California	Block	Near natural gas line
KE-01290	Schiffman 1987	Archaeological Investigations for Southern California Gas Company's 24" Gas Line, Kern County, California	Linear	Near SR 119 intersection improvements
KE-01315		Information pending OEHI's cultural report		Near SR 43/Stockdale Highway intersection improvements

IC Report Number	Citation	Report Title	Survey Type	PAA/APE
KE-01485	Schiffman and Monday 1982	Archaeological Evaluation for the Proposed Belridge Field Cogeneration Plant Kern County, California	Linear	Process water line
KE-01633		Information pending OEHI's cultural report		Near SR 43/Stockdale Highway intersection improvements
KE-01728		Information pending OEHI's cultural report		Near SR 43/Stockdale Highway intersection improvements
KE-01733	Valdez 1991	An Archaeological Assessment of 40 Acres of Land Northeast of Buttonwillow, Kern County, California	Block	Near natural gas line
KE-01740		Information pending OEHI's cultural report		Near SR 43/Stockdale Highway intersection improvements
KE-01810	Woodward 1983	Proposed Capture Pen and Buried Telephone Lines	Block	Near project site, controlled area, potable water line, transmission line
KE-01811	Hartzell 1992	Hunter-gatherer Adaptive Strategies and Lacustrine Environments in the Buena Vista Lake Basin, Kern County, California	Block	Near project site, controlled area, potable water line, transmission line
KE-01813	Woodward-Clyde Consultants 1985	Supplemental Report Cultural Resources Inventory South Belridge Cogeneration Project Application for Certification	Linear	Process water line
KE-01877	Osborne 1993	Archaeological Testing at CA-KER-3397, Northeast of Dustin Acres, Kern County, California	Test	Near SR 119 intersection improvements
KE-01892	Peak & Associates 1992	Report on Archeological Testing of Twelve Sites on Naval Petroleum Reserve No. 1, Kern County, California	Test	Near CO_2 line
KE-01899		Information pending OEHI's cultural report		Near EOR oil field
KE-01924		Information pending OEHI's cultural report		EOR oil field
KE-02015	Reinoehl 1991	Tule Elk State Reserve Cultural Resource Survey	Block	Near project site, controlled area, potable water line, transmission line
KE-02055	Eidsness 1998	Archaeological Inventory and Assessment for Proposed Trash Clean-Up at 17 Localities in Naval Petroleum Reserve No. 1, Elk Hills, Kern County,	Small areas	Near EOR oil field, CO_2 line

IC Report Number	Citation	Report Title	Survey Type	PAA/APE
		California		
KE-02116		Information pending OEHI's cultural report		Near potable water and transmission lines
KE-02162	Hatoff 1998	Cultural Resources Technical Report for the La Paloma Generating Project: Supplement to Appendix L, Completion of Route 1 Survey	Linear/ Block	Near process water line
KE-02219, KE-02377	DOE and DOI 1994	Joint Environmental Assessment for the Construction and Routine Operation of a 12-Kilovolt (kV) Overhead Powerline Right-of-Way, and Formal Authorization for a 10-Inch and 8-Inch Fresh Water Pipeline…Naval Petroleum Reserve	Linear	Near SR 119 intersection improvements
KE-02268	Jackson et al.1998	Prehistoric Archaeological Resources Inventory and Evaluation at Naval Petroleum Reserve No. I (Elk Hills), Kern County, California	Block	CO_2 line; near project site and controlled area
KE-02269	Jackson et al. 1997	Prehistoric Archaeological Extended Inventory Research at Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California	Blocks	Near CO_2 line, project site, and controlled area
KE-02271	Hatoff 1999	The La Paloma Generating Project Supplement #2 to Appendix H	Linear/ Block	Near process water line
KE-02278	Jones & Stokes Associates 1999a	Cultural Resources Inventory Report for Williams Communication, Inc. Fiber Optic Cable System Installation Project San Luis Obispo to Bakersfield	Linear	Process water line, abuts controlled area; near project site
KE-02323	Jones & Stokes Associates 1999b	Cultural Resources Inventory Report for Williams Communication, Inc., Fiber Optic Cable System Installation Project San Luis Obispo Counties, California	Linear	Process water line
KE-02375	Jackson, Shapiro, and King 1999	Prehistoric Archaeological Resources Inventory and Evaluation at Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California	Block	Near CO_2 line, project site, and controlled area
KE-02391	Jackson and Shapiro 1999	Cultural Resources Inventory for the Proposed Texaco Sunrise Cogeneration and Power Project: Addendum for Route B and Valley Acres Substation Surveys	Block/Linear	Process water line
KE-02394	Laylander 1999	Negative Archaeological Survey Report: Installation of Traffic Surveillance Stations at 21 Locations	Small blocks	Natural gas line
KE-02412		Information pending OEHI's cultural report		Near EOR oil field and SR 119 intersection improvements
KE-02452	WZI 2000	Western Midway Sunset Cogeneration Company Project	Linear	Near process water line
KE-02527	Foster 2001	Archaeological Survey for the CALPEAK #3, Midway Kern County,	Linear	Natural gas line, railroad spur

IC Report Number	Citation	Report Title	Survey Type	PAA/APE
		California		
KE-02561	Hatoff 2001	La Paloma Generating Project Preliminary and Final Cultural Resources Report (Condition of Certification CUL-13)	Block	Process water line
KE-02581	Culleton et al. 2001	Confidential Report: Cultural Resources Inventory, Evaluation, and Mitigation Plan for the Water Supply Line (Route 2), Elk Hills Power Plant Project	Mitigation plan	Near EOR oil field and SR 119 intersection improvements
KE-02584	Christy 2001	Archaeological Investigation of the Energy Works Buttonwillow Project Kern County, California	Linear	Process water line
KE-02817	Gassner 2003	Archaeological Survey Report for the Cherry Avenue 4-Lane Project, CA-KER-119, Kern County	Linear	SR 119 intersection improvements
KE-02885	Mealy 2004	Archaeological Testing Report for the Restroom Replacement Project at Tule Elk State Reserve	Test	Near project site, controlled area
KE-03045	Jackson et al. 2003	Final Cultural Resources Report for the Sunrise Power Project Phase I	Block/ Linear	Process water line
KE-03054	Billat 2005	New Tower Submission Packet: Semi-Tropic CA-3224A	Block	Controlled area; near project site
KE-03281		Information pending OEHI's cultural report		Near EOR oil field
KE-03344	Bissonnette 2006	Archaeological Monitoring Report Central Valley District	Block	Near project site, transmission line, potable water line
KE-03419		Information pending OEHI's cultural report		Near SR 43/Stockdale Highway intersection improvements
KE-03482		Information pending OEHI's cultural report		SR 43/Stockdale Highway intersection improvements
KE-03503	Shapiro 1999	Prehistoric Archaeological Resources Inventory and Evaluation at Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California	Block	CO_2 line; near project site, controlled area, and other EOR facilities
KE-03508	Jackson and Shapiro 1997	Cultural Resources Management Plan Naval Petroleum Reserve No. 1 Elk Hills, Kern County, California	Block	CO_2 line; near project site, controlled area, and other EOR facilities
KE-03509	Hamusek-McGann et al. 1997	Historical Resources Evaluation and Assessment Report of Western Naval Petroleum Reserve No. 1, Elk Hills, Kern County, California	Block	CO_2 line, other EOR facilities; near project site and controlled area

IC Report Number	Citation	Report Title	Survey Type	PAA/APE
KE-03674		Information pending Oxy's cultural report		Near SR 43/Stockdale Highway intersection improvements
KE-03691	Gorden 2008	Archaeological Reconnaissance Survey of the Perimeter at the Buttonwillow Ecological Reserve	Linear	Natural gas line

The records searches indicate that while 59 cultural resources are known for the record search area, only 12 are located in the PAA/APE (**Cultural Resources Table 4**).

Cultural Resources Table 4
Known Cultural Resources Located in the Vicinity of the Proposed HECA Project

Resource Designation	Type	Description	Previously Known/ New	Project Component	NRHP/ CRHR Status	Source
Prehistoric Archaeological Resources						
CA-KER-52 (P-15-52)	Lithic scatter		Previously known	Near Midway Substation	Not evaluated	URS 2013a:Table 3.3-1
CA-KER-86 (P-15-86)	Midden/Long term habitation	"Indian Burial Mound." No other information recorded.	Previously known	Near process water line	Not evaluated	Fenenga 1954a
CA-KER-88 (P-15-88)	Midden/Long term habitation	"Indian Burial Mound." No other information recorded.	Previously known	Near process water line	Not evaluated	Fenenga 1954b
CA-KER-124 (P-15-124)	Midden/Long term habitation	Midden with shell and lithics.	Previously known	Controlled area	Not evaluated	Payen 1963a
CA-KER-125 (P-15-125)	Multi-constituent/Short term habitation	Shell and lithic scatter. No other information recorded.	Previously known	Near project site and controlled area	Not evaluated	Payen 1963b
CA-KER-126 (P-15-126)	Midden/Long term habitation	Site not relocated: Large midden (5 ac +) gray soil, FCR, high density shell, shell ornaments, lithic flakes and tools. Likely damaged by California Aqueduct construction.	Previously known	Near project site, controlled area	Not evaluated	Payen et al. 1963
CA-KER-171 (P-15-171)	Midden/Long term habitation	Site not relocated: Occupation site near Dover Well. No other information recorded. Likely damaged by California Aqueduct construction.	Previously known	Process water well field	Not evaluated	Latta 1950

Resource Designation	Type	Description	Previously Known/ New	Project Component	NRHP/ CRHR Status	Source
CA-KER-179 (P-15-179)	Midden/Long term habitation	Burial mound	Previously known	Near process water line	Not evaluated	Pilling 1950
CA-KER-325 (P-15-325)	Midden/Long term habitation	Dense shell, 32 olive snail shell beads, steatite reel and other artifacts, chert and obsidian debitage and projectile points	Previously known	Near railroad spur	Not evaluated	WJW and ETW 1970; URS 2013a:Table 3.3-1
CA-KER-358 (P-15-358)	Midden/Long term habitation	Dark midden soil, diffuse shell and lithic scatter, chert, basalt and obsidian debitage and tools, groundstone, soapstone. Tule Elk State Reserve.	Previously known	Near controlled area	Not evaluated	Olsen 1974a; Parr 2002a; Reinoehl 1991; Woodward 1983
CA-KER-1493 (P-15-1493)	Multi-constituent/Short term habitation	Light scatter of shell, chert debitage, groundstone. Likely disturbed by transmission line construction.	Previously known	Near process water line	Not evaluated	Moore 1982
CA-KER-1611 (P-15-1611)	Multi-constituent/Short term habitation	Light scatter of shell, chert, obsidian debitage and tools, slate, hammerstone, burned bone. Surface collection by Hartzell. Tule Elk State Reserve.	Previously known	Near project site, controlled area, transmission line, potable water line	Not evaluated	Hartzell 1992; Mealy 2004; Parr 2002b
CA-KER-1612 (P-15-1612)	Lithic scatter	Lithic scatter, low density scatter of chert debitage. Tule Elk State Reserve.	Previously known	Near project site, controlled area	Recommended ineligible	Reinoehl 1991; Woodward 1983
CA-KER-2329 (P-15-2329)	Multi-constituent/Short term habitation	Temporary camp site. Dispersed scatter of shell and chert debitage. Very dense at the center. Shovel probes excavated in 1997. Damage from firebreak. NPR-1.	Previously known	Near controlled area, CO_2 line	Recommended ineligible	Jackson et al. 1998
CA-KER-2414 (P-15-2414)	Multi-constituent/Short term habitation	Dispersed scatter of shell, chert debitage, burned bone, groundstone. Tule Elk State Reserve.	Previously known	Near project site, controlled area, CO_2 line	Not evaluated	Mealy 2004; Reinoehl 1991
CA-KER-2415 (P-15-2415)	Lithic scatter	Low density chert debitage. Part of CA-KER-359? Tule Elk State Reserve.	Previously known	Near project site, controlled area	Not evaluated	Reinoehl 1991

Resource Designation	Type	Description	Previously Known/ New	Project Component	NRHP/ CRHR Status	Source
CA-KER-2416 (P-15-2416)	Lithic scatter	Low density chert debitage. Mostly destroyed by bulldozer. Tule Elk State Reserve.	Previously known	Near project site, controlled area, CO_2 line	Not evaluated	Reinoehl 1991
CA-KER-2417 (P-15-2417)	Multi-constituent/Short term habitation	Low density shell and chert debitage, burned mammal bone. Two loci. Tule Elk State Reserve.	Previously known	Near project site, controlled area, transmission line, potable water line	Not evaluated	Reinoehl 1991
CA-KER-2419 (P-15-2419)	Multi-constituent/Short term habitation	Low density scatter of shell, chert, basalt, and obsidian debitage and tools. Tule Elk State Reserve.	Previously known	Near project site	Not evaluated	Reinoehl 1991
CA-KER-2420 (P-15-2420)	Lithic scatter	Low density chert and obsidian debitage scatter. Tule Elk State Reserve.	Previously known	Near project site	Not evaluated	Reinoehl 1991
CA-KER-2464 (P-15-2464)	Midden/Long term habitation	Buried midden soil containing lithics and shell.	Previously known	Near project site	Not evaluated	Schulte 1988
CA-KER-2485 (P-15-2485)	Multi-constituent/Short term habitation	Partially destroyed by a bulldozer. Groundstone, flaked stone tools. Two unusual intact projectile points.	Previously known	Near process water line, near BS-IF-003	Not evaluated	Hale and Laurie 2009; Hale et al. 2012; Jackson 1989
CA-KER-2718 (P-15-2718)	Midden/Long term habitation	Several small mounds of midden deposit with scattered shell and lithics.	Previously known	Near process water line	Not evaluated	Laframboise 1990a
CA-KER-2719 (P-15-2719)	Midden/Long term habitation	Midden soil, obsidian and shell and flakes, shell, and bead scatter. Three olive snail shells: wall, spire-ground, and split-punched.	Previously known	Near process water line	Not evaluated	Laframboise 1990b
CA-KER-2720 (P-15-2720)	Midden/Long term habitation	Midden mound shell, chert debitage and cores. Test excavations revealed cache of charmstones, burial, shell beads, and projectile points. Site dates to between 3500 B.P. to the modern era.	Previously known	Near process water line	Not evaluated	Haas 1997; Jackson and Shapiro 1999; Laframboise 1990c; Sutton 1996

Resource Designation	Type	Description	Previously Known/ New	Project Component	NRHP/ CRHR Status	Source
CA-KER-2721 (P-15-2721)	Midden/Long term habitation	Midden soil with a lithic, groundstone and shell scatter. Testing and surface collection by CSUB. Steatite bowl fragment, Cottonwood Triangular point, Elko projectile point, 12 olive snail shell beads.	Previously known	Near process water line	Not evaluated	Jackson and Shapiro 1999; Laframboise 1990d
CA-KER-3077 (P-15-3077)	Multi-constituent/Short term habitation	Temporary habitation: three loci. Excavated 1992 and 1997. Two ^{14}C dates between 910 and 575 B.P. NPR-1.	Previously known	Near controlled area, CO_2 line, EOR facilities	Recommended ineligible	Jackson et al. 1998; Peak & Associates 1991
CA-KER-3079 (P-15-3079)	Multi-constituent/Short term habitation	Sparse prehistoric shell and lithic scatter, 5.5 ac. Excavation produced flaked and ground stone tools, obsidian, steatite and olive snail shell beads, shell, debitage, faunal remains, and suspected cemetery.	Previously known	Near CO_2 line	Recommended eligible	Hale and Laurie 2009; Henshaw 1997; Peak & Associates 1991, 1992
CA-KER-3088 (P-15-3088)	Lithic scatter		Previously known	Near electrical switching station	Not evaluated	URS 2013a:Table 3.3-1
CA-KER-3163 (P-15-3163)	Multi-constituent/Short term habitation	Sparse scatter of shell, chert flakes and tools. NPR-1.	Previously known	Near EOR pipeline	Recommended ineligible	Peak & Associates 1991
CA-KER-3861 (P-15-3861)	Multi-constituent/Short term habitation	Sparse shell and chert debitage scatter. Disturbed by oil well construction. NPR-1.	Previously Known	Near CO_2 line	Recommended ineligible	Clift 1993; Jackson et al. 1998
P-15-6026	Unknown	Unknown	Previously Known	Near electrical switching station and transmission line	Unknown	
CA-KER-5362 (P-15-6734)	Multi-constituent/Short term habitation	Temporary campsite. Sparse shell scatter. No diagnostic artifacts. NPR-1.	Previously Known	Near controlled area, CO_2 line	Recommended ineligible	Jackson et al. 1998

Resource Designation	Type	Description	Previously Known/ New	Project Component	NRHP/ CRHR Status	Source
CA-KER-5363 (P-15-6735)	Multi-constituent/Short term habitation	Temporary campsite. Sparse shell scatter. No diagnostic artifacts. NPR-1.	Previously Known	Near controlled area, CO_2 line	Recommended ineligible	Jackson et al. 1998
CA-KER-5392 (P-15-6767)	Multi-constituent/Short term habitation	Continuous, sparse chert lithic and shell scatter with two dense loci. Test excavations revealed olive snail shell beads, ground stone, lithic tools and baked clay. Rectangular mussel beads. Locus A: 1350–1050 B.P. Locus B: 3150 B.P.	Previously known	CO_2 Line; near controlled area	Recommended ineligible	Jackson et al. 1998; Nachmanoff et al. 1999; Peak & Associates 1991
CA-KER-5393 (P-15-6768)	Multi-constituent/Short term habitation	Temporary campsite. Sparse shell scatter. No diagnostic artifacts. NPR-1.	Previously known	Near project site, controlled area, EOR pipeline	Recommended ineligible	Jackson et al. 1998
CA-KER-5394 (P-15-6769)	Multi-constituent/Short term habitation	Temporary campsite. Sparse shell scatter. No diagnostic artifacts. NPR-1.	Previously known	Near EOR pipeline	Recommended ineligible	Jackson et al. 1998
CA-KER-5396 (P-15-6771)	Multi-constituent/Short term habitation	Temporary campsite. Sparse shell scatter. Testing revealed some chert debitage and olive snail shell beads. ^{14}C-dated to between 950 and 750 B.P. NPR-1.	Previously Known	Near controlled area, EOR facilities	Recommended ineligible	Jackson et al. 1998
P-15-9734	Lithic scatter	Previously four isolates. Sparse chert debitage and tool scatter.	Previously Known	Near process water line	Not evaluated	Jackson and Shapiro 1999
P-15-9818	Isolate	Shaped pestle	Previously known	Near process water line	Not eligible	URS 2009b:Figure 1, Sheet 5
P-15-9819	Unknown	Unknown	Previously known	Near process water line	Unknown	URS 2009b:Figure 1, Sheet 5
P-15-10238	Isolate	Chert interior flake and burnt bone	Previously known	Near process water line	Not eligible	Aviña 1999; Hale and Laurie 2009:Figure 1, Sheet 5

Resource Designation	Type	Description	Previously Known/ New	Project Component	NRHP/ CRHR Status	Source
CA-KER-6504 (P-15-11157)	Multi-constituent/Short term habitation	Shell, chert debitage, burned bone, steatite ornament, obsidian biface, groundstone scatter. Tule Elk State Reserve.	Previously Known	Near project site, controlled area, transmission line, potable water line	Not evaluated	Mealy and Pettus 2004
Historical Archaeological Resources						
CA-KER-3253H (P-15-3253)	Habitation and trash scatter	Two loci of historic domestic refuse scatter and structural remains. A residence for oil well workers, possibly Pacific Oil Lease. Artifacts date to 1930 and 1950. NPR-1.	Previously known	Near controlled area	Recommended ineligible	Hamusek-McGann et al. 1997; Peak & Associates 1991
Multi-Component Resources						
CA-KER-34/H (P-15-34) CA-KER-35/H (P-15-35) CA-KER-36/H (P-15-36)	Midden/Long term habitation	Remains of three midden mounds (~6 ft high); nine burials with FCR, beads, bone tools, and charmstones, excavated in 1920s. Mounds since leveled. Shell, lithic flakes and tools, groundstone. Likely long-term occupation. Remains of historic Elk Grove Ranch: glass, ceramic, metal.	Previously known	Near process water line	Not evaluated	Gifford and Schenck 1926; Hale and Laurie 2009; Hale et al. 2012; Jackson and Shapiro 1999
CA-KER-89/H (P-15-89)	Midden/Long term habitation	10–12-ft-high mound with human bone, shell beads, chert debitage, turtle and rabbit bone. Purple glass.	Previously known	Near process water line	Not evaluated	Hale and Laurie 2009; Hale et al. 2012; Laframboise 1990e
CA-KER-359/H (P-15-359)	Multi-constituent/Short term habitation	Diffuse shell scatter with four dense loci, chert, basalt and obsidian debitage and tools, steatite bowl, groundstone, Northern side notched point, 19th-century artifacts (metal, glass, ceramics).	Previously known	Near project site, controlled area	Not evaluated	Hale and Laurie 2009; Hale et al. 2012; Olsen 1974b; Parr 2002c; Reinoehl and Hartzell 1987
CA-KER-3105/H (P-15-3105)	Lithic and historic refuse scatter	Chert debitage, basalt core, granitic handstone, fire-affected rock, olive	Previously known	Near natural gas line	Not evaluated	Hale and Laurie 2012; Hale et al. 2012

Resource Designation	Type	Description	Previously Known/ New	Project Component	NRHP/ CRHR Status	Source
		snail shell bead, amethyst glass, solder-top cans, ceramics, license plate				
CA-KER-5356/H (P-15-6725)	**Multi-constituent/ Short term habitation**	**Sparse prehistoric shell and chert debitage scatter. Glass and ceramic scatter.**	**Previously known**	**Near process water line, near P-15-7176**	**Not evaluated**	**Hale and Laurie 2009; Hale et al. 2012; Jackson and Shapiro 1999**
Notes: CSUB = California State University, Bakersfield; FCR = fire-cracked rock						

Additional Archival Research

The applicant conducted additional archival research using print, online, and library/repository sources. Standard online and print sources included the online listings of the NRHP, the CRHR, *California Historical Landmarks*, and *California Points of Historical Interest* (California Department of Parks and Recreation 1992, 1996, cited in URS 2012a:5.3-20). Research concerning the history of the project vicinity and identified historic built environment resources was conducted at the following locations in 2009 and 2012: California State Library, Sacramento; Shields Library, University of California, Davis; Bancroft Library, University of California, Berkeley; Water Resources Center Archives, University of California, Berkeley; Beale Memorial Library, Bakersfield; and the Kern County Museum, Bakersfield (URS 2012a:5.3-24).

The applicant also reviewed historic maps and aerial photographs of the proposed project area to identify potential cultural resource locations (URS 2012a:Tables 5.3-1, 5.3-2). The consulted materials included U.S. Geological Survey (USGS) topographic maps, a county survey map, and General Land Office (GLO) survey plats.

In 2012, staff conducted additional research at the California History Room of the California State Library in Sacramento, the Cadastral Survey Office at the Bureau of Land Management in Sacramento, and online sources. The research was conducted to improve the historic map coverage acquired by the applicant. All consulted historic maps and aerial photographs are presented in **Cultural Resources Table 5**.

Cultural Resources Table 5
Historic Maps and Aerial Photographs Consulted

Map Name	Scale	Survey Date	Reference
Survey Plat, T 28 S, R22 E	Not specified	1852–1855	GLO 1856a
Survey Plat, T 30 S, R23 E	Not specified	1852, 1853, 1855	GLO 1856b
Survey Plat, T 30 S, R 24 E	Not specified	1852, 1853, 1855	GLO 1856c
Survey Plat, T 29 S, R 24 E	Not specified	1852, 1853, 1855	GLO 1856d
Survey Plat, T 31 S, R 23 E	Not specified	1852, 1853, 1855	GLO 1856e

Map Name	Scale	Survey Date	Reference
Survey Plat, T 31 S, R 24 E	Not specified	1852, 1853, 1855	GLO 1856f
Survey Plat, T 29 S, R22 E	Not specified	1853 and 1855	GLO 1856g
Survey Plat, T 29 S, R 23 E	Not specified	1853 and 1855	GLO 1856h
Survey Plat, T 29 S, R 25 E	Not specified	1853 and 1855	GLO 1855a
Survey Plat, T 30 S, R 25 E	Not specified	1853 and 1855	GLO 1855b
Survey Plat, T 31 S, R 25 E	Not specified	1853 and 1855	GLO 1855c
Survey Plat, T 32 S, R 25 E	Not specified	1853 and 1855	GLO 1855d
Survey Plat, T 32 S, R 26 E	Not specified	1853 and 1855	GLO 1855e
Survey Plat, T 28 S, R 22 E	Not specified	1868	GLO 1868a
Survey Plat, T 29 S, R 22 E	Not specified	1868	GLO 1868b
Survey Plat, T 29 S, R 23 E	Not specified	1868	GLO 1868c
Survey Plat, T 29 S, R 24 E	Not specified	1868	GLO 1868d
Survey Plat, T 30 S, R 24 E	Not specified	1868	GLO 1868e
Survey Plat, T 31 S, R 25 E	Not specified	1868	GLO 1868f
Survey Plat, T 32 S, R 25 E	Not specified	1868	GLO 1868g
Survey Plat, T 32 S, R 26 E	Not specified	1868	GLO 1868h
Official Map of Kern County	1 inch = 3 miles	1875	von Leicht and Kaufman 1875
Detail Irrigation Map	1 inch = 1 miles	1885	Hall 1885
Survey Plat, T 30 S, R 24 E	Not specified	1893	GLO 1894
Survey Plat, T 30 S, R 23 E	Not specified	1893, 1901	GLO 1902
Official Map of Kern County	1 inch = 2 miles	1898	Congdon 1898
Map of Kern County	Not specified	1904	Aubury 1904
Profile: Lokern Junction to Olig	Not specified	1908	SPRC 1908
Survey Plat, T 31 S, R 23 E	Not specified	1908	GLO 1910a
Survey Plat, T 31 S, R 24 E	Not specified	1908	GLO 1910b
Official Map of Kern County	Not specified	1912	Buffington 1912
Buena Vista Lake	1:25,000	1912	USGS 1912
Weber's Map of Kern County	Not specified	1914	Punnett Bros. 1914
Map of Kern County	1 inch = 1 miles	1918	Stegman 1918
Rio Bravo	1:31,680	1926	USGS 1931

Map Name	Scale	Survey Date	Reference
East Elk Hills	1:31,680	1927 and 1929	USGS 1932a
Tupman	1:31,680	1927 and 1929	USGS 1933
Tupman	1:31,680	1927 and 1929	USGS 1942
West Elk Hills	1:31,680	1927 and 1929	USGS 1932b
Buttonwillow	1:31,680	1928–1929	USGS 1932c
Lokern	1:31,680	1931	USGS 1932d
Aerial Photograph	1:1,000	1946	URS 2012a:Table 5.3-2
Buttonwillow	1:24,000	1952	USGS 1954a
East Elk Hills	1:24,000	1952	USGS 1954b
Lokern	1:24,000	1952	USGS 1954c
Rio Bravo	1:24,000	1952	USGS 1954d
Tupman	1:24,000	1952	USGS 1954e
West Elk Hills	1:24,000	1952	USGS 1954f
Aerial Photograph	1:1,000	1956	URS 2012a:Table 5.3-2
Aerial Photograph	1:1,000	1967	URS 2012a:Table 5.3-2

Native American Consultation

Native American Heritage Commission

The Governor's Executive Order B-10-11, executed on September 19, 2011, directs state agencies to engage in meaningful consultation with California Indian tribes on matters that may affect tribal communities. The Energy Commission Siting Regulations require applicants to contact the NAHC for information on Native American sacred sites and a list of Native Americans interested in the project vicinity. The applicant is then required to notify the Native Americans on the NAHC list about the project. The applicant must also provide to the Energy Commission in the AFC a copy of all correspondence with the NAHC and Native Americans and any written responses received, as well as a written summary of any oral responses (20 Cal. Code Regs., §1704(b)(2), App. B(g)(2)(D)). The applicant conducted Native American outreach multiple times over three years (2008–2010). A summary of the applicant's Native American outreach efforts can be found at Table 5.3-5 of the Amended AFC (URS 2012a:5.3-63 through 5.3-65) and immediately following this introduction.

The NAHC is the primary California government agency responsible for identifying and cataloging Native American cultural resources, providing protection to Native American human burials and skeletal remains from vandalism and inadvertent destruction, and preventing irreparable damage to designated sacred sites and interference with the expression of Native American religion in California. It also provides a legal means by which Native American descendants can make known their concerns regarding the need for sensitive treatment and disposition of Native American burials, skeletal remains, and items associated with Native American burials.

The NAHC maintains two databases to assist cultural resource specialists in identifying cultural resources of concern to California Native Americans, referred to by staff as Native American ethnographic resources. The NAHC's Contacts database has the names and contact information for individuals, representing a group or themselves, who have expressed an interest in being contacted about development projects in specified areas. The NAHC's Sacred Lands File has records for places and objects that Native Americans consider sacred or otherwise important, such as cemeteries and gathering places for traditional foods and materials. However, the Sacred Lands File only contains those resources that tribes are willing to disclose to the NAHC and cannot be considered a comprehensive list of areas, places, objects, or sites that Native Americans consider sacred or otherwise important.

Staff requested that the NAHC perform a Sacred Lands File check. On June 12, 2012, the NAHC responded that the Sacred Lands File did not contain any information that pertained to the area. A list of tribal contacts was also provided. The NAHC response to the Energy Commission request was similar to NAHC responses to the applicant's Sacred Lands File search requests.

General Tribal Government Background

At the time of PSA/DEIS publication, three tribal governments out of the seven invited tribal governments and one tribal organization are engaged with staff concerning the proposed project (**Cultural Resources Table 6**). General information concerning these contemporary tribal governments is presented below. Essentially, the proposed project is in the traditional territory of the Southern Valley Yokuts and the ethnographic context included in this document, focuses on Southern Valley Yokuts cultural practices. Other tribal affiliations are included here because these tribes also maintain traditional ties to the project vicinity.

By way of background, federal recognition is the process through which the federal government establishes a relationship with a sovereign Native American tribal government, or Indian tribe. Federal recognition status allows tribes to receive certain financial and cultural benefits, such as grant money and repatriation of some cultural materials. Not all of the tribes with which the Energy Commission consults are recognized by the federal government, but because the Energy Commission is a state agency, recognition by the federal government is not necessary for tribes to participate in consultation with the Energy Commission.

Cultural Resources Table 6
Summary of Tribal Participation

Tribe	Cultural Affiliation	Project Participation
Santa Rosa Rancheria	Tachi (Yokuts), Yokuts	Yes
Tejon Indian Tribe	Yowlumne (Yokuts), Kitanemuk, Kawaiisu	Yes
Kitanemuk and Yowlumne Tejon Indians	Yowlumne (Yokuts), Kitanemuk	Yes
Kawaiisu Tribe of the Tejon Reservation	Kawaiisu	No
Tule River Indian Tribe	Yokuts	No
Kern Valley Indian Council	Southern Paiute, Kawaiisu, Tubatulabal, Koso, Yokuts	No
Tubatulabals of Kern Valley	Tubatulabal	No

Yokuts

The reservation period for the Yokuts began with the influx of white settlers in the mid-nineteenth century, and the push by the settlers for more land. As a result, treaties were negotiated in 1851 and 1852 between the extant Yokuts tribes of the San Joaquin Valley and the United States government. The Native Americans negotiated in good faith and agreed to cede their lands for 10 reservations throughout Central California and payments in goods. The U.S. Senate did not ratify the treaties. Consequently, some of the Native American groups stayed on their traditional lands, while others relocated to one of the reservations that had already been established near the base of the Tehachapi range, or the Fresno reservation near Madera. Life was difficult for Native Americans in the San Joaquin Valley at this time, and many people became destitute and dependent upon white people who employed them as day laborers. (Wallace 1978b:460).

Santa Rosa Rancheria

The Santa Rosa Rancheria is the federally recognized reservation of the Tachi Yokuts. It was established in 1934[24] on 40 acres of land near Lemoore, California, and close to the site of an old Indian village, Wiu (Cummins 1978:55). The Tachi-Yokuts traditionally resided around Tulare Lake, from the southwest portion of the lake clockwise to the northern edge (Latta 1999:back cover). The initial reservation was small, and only 40 people lived there, in relative destitution. By the 1980s, the reservation had been expanded to 170 acres and by then about 200 people resided there. The Santa Rosa Rancheria remained relatively impoverished until 1988 when the Indian Gaming Regulatory Act was passed, allowing tribes to own and operate their own casinos. Today, the Santa Rosa Rancheria is governed by a six-member tribal council, consisting of a chairman, vice-chairman, secretary, treasurer, and two delegates. The tribe does not have a Tribal Historic Preservation Officer (THPO), but does have a director of their Cultural and Historical Preservation Department. (Tachi-Yokut Tribe 2012a, 2012b, 2012c).

Kitanemuk and Yowlumne Tejon Indians

The Kitanemuk are a small group of Native Americans who traditionally resided in the Tehachapi Mountains at the southern end of the San Joaquin Valley. They spoke a dialect of the Serran language, a branch of the Takic family group and were primarily mountain dwellers, but occasionally during cooler months would range into the lowlands to the south. They had an antagonistic relationship with the Yokuts to the north and the Tataviam to the south, but were on friendly terms with the Chumash to the west and Tubatulabal to the northeast. Culturally, the Kitanemuk were influenced by the Yokuts and Chumash, especially in their ritual, mythology, and shamanism. (Blackburn and Bean 1978:564).

The Kitanemuk and Yowlumne Tejon Indians Tribe is not federally recognized, and does not have an established reservation or cultural resources management department. However, Chairperson Delia Dominguez has been working for 16 years to gather the necessary information for the U.S. government and petition them for federal recognition. (Hedlund 2009).

Tule River Indian Tribe

The Tule River Reservation was established by an executive order issued by President Ulysses S. Grant on January 9, 1873. The reservation originally comprised about

[24] Cummins (1978:55) suggests that the reservation was established in 1921; the 1934 date comes from the Tachi Yokuts Tribe’s website.

48,000 acres of land located about 20 miles east of Porterville. Today the reservation covers about 54,400 acres with about 850 tribal members in the area. (White 2012). The federally recognized Tule River Tribe maintains a nine-member tribal council, consisting of a chairman, vice-chairman, treasurer, secretary, and five elected members. The tribe does not currently have a THPO, but does maintain an archaeological resource protection program. (Tule River Indian Tribe 2011a, 2011b).

Tejon Indian Tribe

The Tejon Indian Tribe is a recent federally re-recognized tribe consisting of members from the Yowlumne, Kitanemuk, and Kawaiisu groups. After having spent several years with their status as a federally recognized tribe in question, the Tejon Indian Tribe received confirmation of their status as a federally recognized tribe on January 3, 2012. Due to an administrative error, the Tejon Indian Tribe was not listed for several years on the Federal Register as having a relationship with the federal government. However, in a letter to the tribe from the Assistant Secretary of Indian Affairs, confirmation of their status was given, and in the Federal Register published August 10, 2012, the Tejon Indian Tribe was listed as a federally recognized tribe (USDOI 2012). Due to their newly confirmed status, details regarding the Tejon Indian Tribe's tribal government are limited.

Kawaiisu

Located in the area southeast of the Kern River in the Sierra Nevada foothills, these Native Americans speak a dialect of the Ute-Chemehuevi division of the Shoshonean language (Kroeber 1976:601). Consisting of about 250 members, the Kawaiisu tribe maintains the Kawaiisu Language and Cultural Center in Bakersfield where they offer the opportunity to learn more about the Kawaiisu culture (Kawaiisu Language and Cultural Center 2012).

Kawaiisu Tribe of the Tejon Reservation

The Kawaiisu Tribe of the Tejon Reservation is not a federally recognized tribe. However, they do maintain a tribal council with elected members; chair, vice-chair, secretary, treasurer, and a member at large. They have adopted a constitution which lays out their territory, jurisdiction, membership rules, what the governing body is and its powers, the rights of members, how elections are conducted, how one is removed from office, and other aspects relevant for conducting tribal affairs. (Kawaiisu Tribe 2012).

Tubatulabal

Residing in the southern Sierra Nevada in the vicinity of the Kern Valley, the Tubatulabal tribe spoke a dialect of the Uto-Aztecan language, Tubatulabal. Little is known of the Tubatulabal prior to 1850, but during historic times the Tubatulabal moved in small bands to exploit local area resources and then would return to their larger settlements along the rivers. (Voegelin 1941:2.) During the early twentieth century, many Tubatulabal members moved to the Tule River Indian Reservation, and others remained in the Kern Valley where they obtained employment through white settlers (Smith 1978:437–438).

Tubatulabals of Kern Valley

The Tubatulabals of Kern Valley are a non-federally recognized tribe based out of Lake Isabella, California. Today there are about 400 Tubatulabal people living in the Kern River Valley, with estimates of about 500 Tubatulabal outside of the area, some residing on the Tule River Indian Reservation. (White 2012).

Kern Valley Indian Council

The Kern Valley Indian Council is a non-federally recognized Native American entity. The council was established in 1984 to protect the interests of their members and consists of people belonging to the Southern Paiute, Kawaiisu, Tubatulabal, Koso, and Yokuts tribes. In 1986 the Council established the Foundation for the Kern Valley Indian Community. (National Geographic Society 2009).

Applicant's Methods and Results

URS, consultant to the applicant, contacted the NAHC seven times as the project footprint changed over the course of the last five years (2008–2013). The last effort at URS–NAHC contact and related outreach to tribal entities was initiated in the summer of 2010. On August 2, 2010 the NAHC responded to URS requests that the NAHC search its Sacred Lands File to determine whether there are any reported Native American cultural resources in the proposed project area, and to request that the NAHC provide a list of Native American contacts that may have knowledge of cultural resources in the project area. This response letter also indicated that the Sacred Lands File did not indicate the presence of any Native American cultural resources within 0.5 mi of the project site. The NAHC also provided a list of tribal entities to contact. On August 3 and 4, 2010, URS sent letters to the NAHC-listed tribal entities. On August 26 and 27, URS cultural resources staff conducted follow-up phone calls. The cultural resources representative of the Santa Rosa Rancheria and a tribal individual both advised URS that the general area was known to contain burials and that a tribal monitoring program with sensitivity be developed. The Santa Rosa Rancheria went as far as to suggest that a burial agreement be considered. (URS 2012a:5.3-63, Table 5.3-5).

Department of Energy Consultation

Pursuant to direction under federal regulations, policies, and orders, DOE consulted with Indian tribes regarding HECA's potential effects on historic properties (16 U.S.C., §470a(d)(6)(B); 36 C.F.R., §§800.2(c)(2)(ii), 800.3(f)(2), 800.4(a)(4), et seq.; DOE Policies 141.1 and 1230.2[25]). DOE identified three Indian tribes (as defined at 36 C.F.R., §800.16[m]) in the proposed project vicinity: Santa Rosa Rancheria, Tule River Indian Tribe, and Tejon Indian Tribe. DOE mailed informal consultation letters to these tribes on May 10, 2012. The letters provided a summary of the proposed project, maps of the proposed project and APE, and requested to "initiate informal government-to-government consultation" (Pozzuto 2012b, 2012c, 2012d). Tejon Indian Tribe responded to DOE by letter on June 5, 2012. The letter states, "Tejon Indian Tribe has no conflict with this project nor do we know of any cultural resources that might be impacted at this site. However, we ask that you notify us immediately if any site/s and / or artifacts are discovered during your project in the area." (Montes Morgan 2012).

[25] DOE 1992:Attachment 1, 2001:3.

These items of correspondence are reproduced in Appendix CUL-1 to this PSA/DEIS. Tejon Indian Tribe, however, elected to have further involvement in environmental impact review for the proposed project, as discussed below and in the subsection, “Energy Commission Native American Consultation”.

DOE coordinated with Energy Commission cultural resources staff to conduct a face-to-face, government-to-government meeting with Indian tribes in August 2012 and participated in a field review of the proposed EOR project elements on September 26, 2012 with representatives of Tejon Indian Tribe (see discussion under “Energy Commission Native American Consultation” below.

DOE followed up conversation with the Tejon Indian Tribe on October 3, 3012, in which the tribe requested additional mapped cultural resource locations from the Energy Commission. The information and instructions for petitioning to receive copies of confidential information was mailed to the Tejon Indian Tribe on October 3, 2012.

Energy Commission Native American Consultation

In conducting due diligence tribal outreach and information gathering, staff initiated a NAHC request for a search of the Sacred Lands File and a list of tribal contacts for the project vicinity. NAHC responded on June 13, 2012, stating that the Sacred Lands File contained no indication of Native American cultural resources in the project area. The NAHC also provided a list of tribal contacts.

On June 21, 2012, staff sent letters to the seven NAHC-listed tribal governments, one tribal organization, and one individual. On July 9, staff attempted to make verbal contact with all listed tribal entities. Six tribes, the organization, and individual responded. Of the tribes that responded, three requested a meeting to learn more about the project, and the other three tribes said they might request further information later in the process. The individual was interested in being notified of any meetings that might be scheduled to handle information exchange and tribal concerns. This correspondence between Energy Commission cultural resources staff and Native American entities is docketed and available for public review under Docket Unit 08-AFC-8A, TN #65894.

As a result of initial tribal contact, a tribal meeting was planned and scheduled for August 22, 2012. On August 21, 2012, staff was notified that tribes would not attend the scheduled meeting due to a critical issue arising from a non-Energy Commission project. The August 22 meeting was cancelled. Staff attempted to reschedule the meeting, but as a result of additional tribal calls it was determined that a tribal site visit would be more appropriate than a meeting.

During a project field visit on September 26, 2012, two representatives of the Tejon Indian Tribe participated in the visit. During the visit, the Tejon Indian Tribe made a verbal request to receive a copy of a confidential map depicting cultural resources locations that was originally provided to staff by the applicant. The tribe was informed of the Energy Commission’s petitioning process and was provided information on how to petition for confidential information in the possession of staff.

Based upon the level of correspondence and direct communications, a minimal research design, provided in the ethnographic model section below, was developed that generated a few research questions or directives. Staff had identified that the largest tribal issue with other projects in the vicinity is a tribal concern with exposure of unknown Native American burials.

Consultation with Others

Pursuant to its responsibilities under Title 36, Code of Federal Regulations, parts 800.3(a–c) and 800.4(a)(1), DOE initiated informal consultation concerning HECA with the California State Historic Preservation Officer (SHPO) by letter dated May 8, 2012. DOE's consultation letter briefly described the project and defined the proposed project's APE narratively and graphically. DOE requested that the SHPO provide input on or concur with DOE's definition of the APE. (Pozzuto 2012a). The SHPO responded by letter on May 25, 2012, stating that he was unable to concur with DOE's definition of the APE and citing the need for additional information on that subject (Donaldson 2012). On April 24, 2013, DOE mailed a letter to the SHPO, seeking concurrence on its revised APE[26] (Pozzuto 2013). DOE has not received a response from the SHPO as of the date of this PSA/DEIS. (Appendix CUL-2).

Environmental Justice/Socioeconomic Methods

In accordance with federal and state law, regulations, policies, and guidance, staff considered the proposed project's potential to cause significant adverse impacts on environmental justice populations (E.O. 12898; 40 C.F.R., §§1508.8, 1508.14; 14 Cal. Code Regs., §§15064(e), 15131, 15382; 20 Cal. Code Regs., §1704(b)(2), App. B(g)(7); CEQ 1997). **Socioeconomics Figure 1** indicates that an environmental justice population exists within a 6-mile buffer of the proposed project area (see the **Socioeconomics** section of this PSA/DEIS for a discussion of methods and composition of the environmental justice population). In addition, staff reviewed the ethnographic and historical literature, and corresponded with Native American tribes, to determine whether any additional environmental justice populations use or reside in the project area. These efforts are documented in the "Ethnographic Setting" and "Native American Consultation" subsections of this PSA/DEIS.

Cultural Resources Distribution Models

One critical use of the information drawn together during the background research for a cultural resources analysis is to inform the design and the interpretation of the field research that will complete the cultural resources inventory for the analysis. The background research for the present analysis has identified five previously recorded cultural resources in the PAA/APE (see "California Historical Resources Information System Search" section above), and found that little of the PAA/APE has been subject to cultural resources survey. A further role of background research is to help develop predictive or anticipatory models of the distribution of cultural resources across a project area of analysis. Such models of the types of archaeological, ethnographic, and built-environment resources, and the patterns of their distribution across and beneath the surface of the landforms of the PAA/APE, provide the means to tailor more appropriate

[26] While drafting the consultation letter, DOE received more specific information from OEHI concerning the proposed EOR facilities. Consequently, the figures that accompany DOE's letter present an APE that is smaller than the PSA/APE analyzed in this PSA/DEIS. Staff will consider OEHI's revised project components in the FSA/FEIS.

research designs for the field investigations that will complete a cultural resources inventory, and help gauge the degree to which the results of those investigations may reflect the actual population of archaeological, ethnographic, and built-environment resources in the PAA/APE. Such models also provide important contexts for the ultimate interpretation of the results of those investigations.

Models of the distribution of prehistoric archaeological sites, of ethnographic resources, and of historical archaeological sites and built-environment resources are developed here and draw on information above in the “Environmental Setting,” “Prehistoric Setting,” “Ethnographic Setting,” and “Historic Setting” subsections, in addition to the above information in the “Background Research” subsection. Staff formulated data requests during the discovery phase of the present certification process on the basis of these models to ensure the collection of enough information to factually support the conclusions of this analysis. The discussions in the “Interpretation of Results” subsection below also employ the models.

Model of Prehistoric Archaeological Resources

The analysis of the information in the “Environmental Setting,” “Prehistoric Setting,” and “Literature and Records Search” subsections suggests that five site types will be identified within the PAA/APE: Midden (long term habitation) sites, Multi-constituent (short term habitation) sites, lithic scatters, lithic procurement sites, rock feature sites, and cemeteries (Jackson et al. 1998).

Midden or Long Term Habitation Sites

Midden or long term habitation sites consist of deep accumulations of dark midden soil, often forming mounds. The full range of artifact types can be found at these sites including: *Anodonta* (freshwater clam) shell, flaked stone debitage and formed tools, groundstone tools, bird and mammal faunal remains, fire-affected rock, mortuary remains, and marine shell beads. When excavated, features such as hearths and habitations have been found. Evidence of long term occupation of the same location is also possible. Sites of this type are typically located immediately adjacent to bodies of water such as Buena Vista Lake or Buena Vista Slough. Although not within the HECA records search area or PAA/APE, staff places Wedel’s (1941) sites 1 and 2 and CA-KER-116 in this category.

Multi-Constituent or Short Term Habitation Sites

Multi-constituent or short term habitation sites are primarily characterized by spatially extensive distributions of freshwater clamshell. Marine shell beads of olive snails*, Tivela* (Pismo clam), and abalone are also common. Lithic flaked and ground stone artifacts are rare but consistently present. Faunal remains, fire-affected rock and human remains can also be present. These appear to be short-term habitation sites where the full range of domestic activities took place. Discrete activity loci may be identified. Sites of this type have been identified both on the northern slopes of the Elk Hills, along the historic meanders of the Buena Vista Slough, and the Buena Vista Lake shoreline (CA-KER-450) (Barton et al. 2010). The majority of the prehistoric sites in the EOR area fall into this category.

Lithic Scatters

Lithic scatters consist primarily of flaked stone debitage with few, if any, formed tools. In a region where most prehistoric sites are characterized by shell scatters, these sites lack these faunal remains. They appear to be located only along historic meanders of the Buena Vista Slough. A more limited number of tasks appear to have taken place at these sites.

Rock Feature Sites

Rock feature sites are distinguished by concentration of fire-affected rocks. Few, if any, other artifact classes are present. Three sites within the EHOF are classified as rock feature sites. Seven others are known on the boundary or within 1 mi of the EHOF.

Lithic Procurement Sites

Lithic procurement sites consist of large concentrations of chert raw materials and associated flaked stone debris. Occasionally small amounts of shell are present as well. The Temblor chert is usually found in the form of cobbles or pebbles surrounded by a loose sandy matrix. At least four sites within the EHOF have been classified as lithic procurement sites, but all have been severely damaged by road construction.

Cemeteries

Cemeteries are prehistoric sites representing discrete burial grounds. Midden sites that also contain mortuary components are not included in this category. Sites of this type were not identified within the HECA records search area or within the PAA/APE. However, several sites in the immediate vicinity are recognized cemeteries, such as Wedel's (1941) hilltop sites CA-KER-40 and CA-KER-41.

Summary

The analysis of the "Environmental Setting" subsection leads to the conclusion that the likelihood of prehistoric archaeological deposits across the surface of the proposed HECA project site and linear alignments is moderate. Such sites are likely to have been disturbed by industrial and agricultural activities. The likelihood of subsurface prehistoric archaeological deposits ranges from very low to high depending on the geomorphic context. The highest site density is expected near the boundaries of the former slough, anywhere from 0 to 32 feet below the modern ground surface. Buried deposits are likely to be well preserved below the plow zone.

The likelihood of prehistoric archaeological deposits across the surface of the EOR area is also moderate, with higher density to the north along the former slough. The depth of these deposits ranges from 0 to 3 feet below the modern ground surface. These sites are likely to have been disturbed by rodent burrowing, agricultural activities, and oil and gas exploration. However, the likelihood of buried prehistoric archaeological deposits is low.

Method for Ethnographic Resources identification

Methods

Ethnography is a term that refers to a discipline of anthropology, a method, and a type of document. As a discipline, ethnography is the prime focus of cultural anthropology. As a method, ethnography is an endeavor to understand other cultural groups from their point of view. There is significant overlap with ethnography as a general method and Native American consultation as a method and legal requirement. Most human beings are ethnocentric—that is, they tend to think about the world and others in terms of their own cultural experiences. In contrast, as one conducts ethnographic investigations, ethnocentrism, the practice of assessing others only in terms of what we know from our own culture, is to be avoided. In order to understand other cultural groups, ethnographers must first understand their own cultural assumptions, biases, and ways of understanding the world. Cultural self-awareness allows an ethnographer to understand other cultures from the other's point of view. As a type of document, ethnography provides readers with a written account that presents an understanding of another culture as the ethnographer came to understand that other culture from its people's perspectives or world view.

Ethnographers employ some of the following methods to understand other cultures:

- **Ethnographic research**: a review of previous ethnographies concerning the culture to be understood.
- **Historic research**: a review of historic literature about the people, events, and places of cultural importance.
- **Kinship charts**: a method for charting human relations among a culture, clan, community, or family.
- **Extended interviews**: representative individual and group interviews that seek responses to a number of research questions concerning the culture as a whole or sub-areas of the culture.
- **Life history interviews**: documentation of the events that chronicle a person's life story as that person presents their personal history within a broader cultural context.
- **Participant observation**: participating in and observing cultural events as if one were from the culture that one is studying.
- **Journalistic witnessing**: witnessing and documenting a cultural event at face value in descriptive terms without interpretation.

Ethnography fulfills a supporting role for other anthropological disciplines and provides contributions on its own merits. Ethnography supports the discipline of archaeology by providing a cultural and historic context for understanding the people that are associated with the material remains of the past. By understanding the cultural milieu in which archaeological sites and artifacts were manufactured, utilized, or cherished, this additional information can provide greater understanding for identification efforts; for example in making significance determinations per the NHPA or CEQA; eligibility determinations for the NRHP or CRHR; and for assessing if and how artifacts are subject to other cultural resources laws, such as the Native American Graves Protection and Repatriation Act.

In terms of its contributions to other anthropological disciplines, ethnography provides information concerning resources that tend to encompass physical places, areas, elements or attributes of a place or area. Such ethnographic resources have overlap and affinity to historic property types referred to as cultural landscapes, traditional cultural properties, sacred sites, and heritage resources. Studies that focus on specific ethnographic resource types may also take on names such as ethnogeography, ethnobotany, ethnozoology, ethnosemantics, ethnomusicology, etc.

Ethnography draws upon a variety of sources: published literature, archaeology, and living people. Each of these sources presents the information in different tenses because sometimes cultural practices and ideas are expressed as things that *have* happened, and sometimes as things that *are* happening. Consequently, the ethnographer is presented with an “ethnographic present” problem, wherein cultural practices are current yet they are referenced in the text as happening in the past. Therefore, in order to provide a clear understanding of the ethnography the author has used the tense that is presented in the available sources.

The following research design provided general guidance for preliminary archival research and allowed staff to prepare an ethnographic setting section that would be useful for informing the archaeological analysis of the proposed project.

- Research specific Southern Valley Yokuts history and culture beyond what is generally provided in the Amended AFC.
- Research and understand tribal ceremonies performed in the project vicinity. Determine to what extent these ceremonies are still practiced today and to what extent the proposed project would impact such ceremonies.
- Research traditional and current Southern Yokuts burial practices and related ceremonies.
- Research traditional Yokuts settlement patterns and structures.
- Research Southern Valley Yokuts subsistence practices, including trade and trail systems.

Staff made efforts to seek, obtain, and assess culturally relevant information from various archival and other sources.

- Documents were obtained via various internet searches and subsequent downloads.
- Books were obtained from used book stores in the project area and from on-line book purchasing venues.
- Books and manuscripts from the California State Archives were obtained and reviewed.
- Books and manuscripts from the California State Library were obtained and reviewed.

- Books and manuscripts from the Sacramento State University Library were obtained and reviewed.
- Books and manuscripts from the University of California at Davis Library were obtained and reviewed.
- Books and manuscripts from the University of California at Berkeley Anthropology Library were obtained and reviewed.
- Books and manuscripts from the University of California at Berkeley Bancroft Library were obtained and reviewed.

Ethnographic Method Constraints

No constraints to the ethnographic research described above were identified or encountered.

Results

The ethnographic setting provided earlier in this PSA/DEIS was synthesized from archival research. The focus of the research was to provide ethnographic information that supported the archaeological information also presented in the Amended AFC and in this PSA/DEIS. Anticipating that burials may be encountered inadvertently as a result of project ground disturbance, the ethnographic research focused on specific information related to Southern Valley Yokuts burial, settlement, and subsistence practices. While some ethnographic sites (villages) were identified as a result of ethnographic research, these locations are outside the project area. No traditional cultural properties (places) or ethnographic landscapes were identified from reviewing available ethnographic literature. Further, no ethnographic landscapes were identified through literature review or as a result of project site visitation. Affiliated tribal entities have not suggested that such ethnographic landscapes exist. In addition, the project area is radically altered from agricultural and oil extraction activities, leading staff to conclude that were an ethnographic landscape present, its integrity would be severely compromised.

Staff finds that no known ethnographic resources would be affected by the proposed project.

Model of Historic Archaeological Resources

The analysis of the information in the “Environmental Setting,” “Historic Setting,” and “Literature and Records Search” subsections leads to the conclusion that subsurface historic archaeological deposits are most likely present in the PAA/APE and that historic archaeological deposits are likely present in low to moderate frequency across the surface of the PAA/APE.

Background research and windshield and pedestrian surveys of the PAA/APE suggest that the majority of historic archaeological resources would be associated with rural domestic activities, agriculture, and oil extraction. Additionally, some Native American archaeological sites in the records search area contain historic-period materials, some of which might have been deposited after the cessation of Native American occupation of the site.

The earliest historic archaeological materials known in the project vicinity date to as early as the end of the eighteenth century, by which time Southern Valley Yokuts began to acquire goods from Spaniards, mission Indians, and native traders (Wallace 1978b:459). Such goods included glass trade beads, blankets, glass bottles, china, scissors, pocketknives, and European religious icons (Moratto 1984:189; Walker 1947:7–8). The most common distribution of European-manufactured goods in the project vicinity is expected to be among midden sites, other long-term occupation sites, and cemeteries (see “Model of Prehistoric Archaeological Resources”, above).

Locally, archaeological resources originating from rural residential and domestic activities take the form of structural ruins (former homes, barns, and other outbuildings), refuse scatters, privy pits (outhouses), and landscaping. The distribution of many historical archaeological resources is easily discerned by comparing historic archaeological resource locations to both present cultural and landscape features (such as roads and water bodies) and the historic locations of natural and cultural features.

The major class of historic archaeological resource in the proposed EOR area consists of archaeological sites and structures relating to oil extraction. These constitute artifact scatters associated with now-demolished residences and other structures; artifact scatters resulting from household, commercial, and industrial discard; structural remnants; and infrastructure (oil and water pipes). The distribution of residential resources is expected to correspond closely with flat or gently sloping terrain. Other oilfield features are likely to have a wider, more eclectic—if ubiquitous—presence in the EOR area, owing to the limitations of topography, which necessitated the placement of surface piping over dissected or undulating terrain.

Cultural Resources Inventory Fieldwork

The field efforts to identify the cultural resources in the PAA/APE include an initial geoarchaeology study and intensive pedestrian surveys (**Cultural Resources Table 7**). While the complete results of these efforts are not yet available, 34 new cultural resources have been found to date in the PAA/APE, not including the discovery of 19 isolated finds. Additionally, previously known cultural resources have been updated. On the basis of the background research for the present analysis and the results of the field efforts that are presently available, the total cultural resources inventory for the project area of analysis includes 21 non-isolate archaeological resources, no ethnographic resources, and 21 built-environment resources. (**Cultural Resources Tables 8–10**.)

Cultural Resources Table 7
Cultural Resources Inventory Investigations for the Present Analysis

Investigation Type	Results	Report Reference
Geoarchaeology Study	Conclusion that surface and subsurface potential for archaeological varies from low to high across the PAA/APE	Hale et al. 2012; URS 2012a:5.3-23, 5.3-24;
Intensive Pedestrian Cultural Resources Surveys	Relocated previously recorded archaeological sites, new archaeological sites, and isolated artifacts	Farmer 2008; Hale and Laurie 2009, 2010, 2012, 2013; Hale et al. 2012; Stantec 2011; URS 2013a

Investigation Type	Results	Report Reference
Historic Built Environment Survey	Identified and evaluated both previously recorded and newly found historic built environment resources	JRP 2009, 2012; URS 2010

Cultural Resources Table 8
Present Inventory of Archaeological Resources in the PAA/APE

Cultural Resource Type	Description	Location	CRHR and NRHP Status	Siting Case Report Reference
Prehistoric Archaeological Resources				
HECA Project				
CA-KER-171 (P-15-171)	Midden (long-term habitation) or Multi-constituent (short-term habitation) site	Process water line	Not evaluated	Hale et al. 2012:39; URS 2012a:5.3-27
CA-KER-179 (P-15-179)	Cemetery	Process water well field and process water line	Not evaluated	Hale et al. 2012:43; URS 2012a:5.3-30, 5.3-31
CA-KER-2485 (P-15-2485) and BS-IF-003	Multi-constituent/short-term habitation site	Process water line	Not evaluated	Farmer 2008:Table 5-1; Hale et al. 2012:43; URS 2012a:5.3
CA-KER-3108 (P-15-3108)	Multi-constituent/short-term habitation site	Natural gas line	Not evaluated	Hale et al. 2012:39
CA-KER-5392 (P-15-6767)	Multi-constituent/short-term habitation site	CO_2 line; near controlled area	Recommended eligible	Stantec 2011:8, 9, Table 1
CA-KER-5401 (P-15-6776)	Multi-constituent/short-term habitation site	CO_2 line	Requires evaluation	Stantec 2011:8

Cultural Resource Type	Description	Location	CRHR and NRHP Status	Siting Case Report Reference
ECA-12	Multi-constituent/short-term habitation site	CO_2 line	Recommended potentially eligible under CEQA	Farmer 2008:5-10, 6-1; HEI, with URS 2008:5.3-34, 5.3-35, 5.3-46
HECA-2008-1 (JM-BVWD-1)	Multi-constituent (short-term habitation) site	Process water line	Not evaluated	Hale et al. 2012:40; URS 2012a:5.3-28
HECA-2009-2	Lithic scatter with special function	CO_2 line, controlled area	Not evaluated	Hale et al. 2012:40; URS 2012a:5.3-28
HECA-2009-9	Lithic scatter with special function	Process water well field, process water line	Not evaluated	Hale et al. 2012:40–41; URS 2012a:5.3-28, 5.3-29
HECA-2009-10	Lithic scatter with special function	Process water well field, process water line	Not evaluated	Hale et al. 2012:41, Figure 1, Sheet 1; URS 2012a:5.3-29
HECA-2010-1	Lithic scatter	Electrical switching station buffer	Not evaluated	Hale and Laurie 2013:10; URS 2013a:3-4
P-15-7176 (ISO-JJ1)	Isolated flake	Process water line	Ineligible under CEQA & NRHP	Farmer 2008:Table 2-2; HEI, with URS 2008:5.3-46
BS-IF-001	Isolated find (two pieces of debitage)	Process water line	Ineligible under CEQA & NRHP	Farmer 2008:Table 5-1; HEI, with URS 2008:5.3-46
BS-IF-002	Isolated flake	Process water line	Ineligible under CEQA & NRHP	Farmer 2008:Table 5-1; HEI, with URS 2008:5.3-46
BS-IF-003	Isolated flake	Process water line	Ineligible under CEQA & NRHP	Farmer 2008:Table 5-1; HEI, with URS 2008:5.3-46
BS-IF-004	Chopper and three freshwater mussel shells	Process water line	Recommended ineligible under CEQA & NRHP	Farmer 2008:Table 5-1; HEI, with URS 2008:5.3-46
JM-IF-001	Isolated flake	Process water line	Ineligible under CEQA & NRHP	Farmer 2008:Table 5-1; HEI, with URS 2008:5.3-46
KRM-IF-002	Isolated core	Process water line	Ineligible under CEQA & NRHP	Farmer 2008:Table 5-1; HEI, with URS 2008:5.3-46
KRM-IF-003	Three pieces of debitage	Process water line	Recommended ineligible under CEQA & NRHP	Farmer 2008:Table 5-1; HEI, with URS 2008:5.3-46

Cultural Resource Type	Description	Location	CRHR and NRHP Status	Siting Case Report Reference
KRM-IF-004	Isolated flake	Process water line	Ineligible under CEQA & NRHP	Farmer 2008:Table 5-1; HEI, with URS 2008:5.3-46
KRM-IF-005	Isolated find (two pieces of debitage)	Process water line	Ineligible under CEQA & NRHP	Farmer 2008:Table 5-1; HEI, with URS 2008:5.3-46
HECA-ISO-2	Isolated find (two pieces of debitage)	CO_2 line	Ineligible under CEQA & NRHP	Farmer 2008:Table 5-1; HEI, with URS 2008:5.3-46
HECA-2008-6	Multi-constituent (short-term habitation) site	CO_2 line	Recommended ineligible under CEQA	Farmer 2008:5-7, 6-1; HEI, with URS 2008:5.3-32
HECA-2008-7	Multi-constituent (short-term habitation) site	CO_2 line	Recommended eligible under CEQA	Farmer 2008:5-7, 5-8, 6-1; HEI, with URS 2008:5.3-33
HECA-2008-11	Multi-constituent (short-term habitation) site	CO_2 line	Recommended eligible under CEQA	Farmer 2008:5-9, 6-1; HEI, with URS 2008:5.3-34, 5.3-35
Isolated Artifact 1	Isolated biface	CO_2 line	Ineligible under CEQA & NRHP	Stantec 2011:8
HECA-2009-ISO-1	Isolated projectile point	Controlled area	Ineligible under CEQA & NRHP	Hale and Laurie 2009:39, Appendix C
HECA-2009-ISO-2	Isolated scraper	Project site	Ineligible under CEQA & NRHP	Hale and Laurie 2009:39, Appendix C
HECA-2009-ISO-3	Isolated biface	Project site	Ineligible under CEQA & NRHP	Hale and Laurie 2009:39, Appendix C
HECA-2009-ISO-4	Isolated core	Controlled area	Ineligible under CEQA & NRHP	Hale and Laurie 2009:39, Appendix C
HECA-2009-ISO-5	Isolated projectile point	Project site	Ineligible under CEQA & NRHP	Hale and Laurie 2009:39, Appendix C
HECA-2009-ISO-6	Isolated projectile point	Controlled area	Ineligible under CEQA & NRHP	Hale and Laurie 2009:39, Appendix C
HECA-2009-ISO-7	Isolated flake tool	Project site	Ineligible under CEQA & NRHP	Hale and Laurie 2009:39, Appendix C
HECA-2009-ISO-8	Isolated flake	Controlled area	Ineligible under CEQA & NRHP	Hale and Laurie 2009:39, Appendix C
HECA-2009-ISO-9	Isolated handstone	Controlled area	Ineligible under CEQA & NRHP	Hale and Laurie 2009:39, Appendix C

Cultural Resource Type	Description	Location	CRHR and NRHP Status	Siting Case Report Reference
		EOR Project		
CA-KER-5401 (P-15-6776)	Multi-constituent/short-term habitation site	CO_2 line	Requires evaluation	Stantec 2011:8
HECA-2008-6	Multi-constituent (short-term habitation) site	CO_2 line	Recommended ineligible under CEQA	Farmer 2008:5-7, 6-1; HEI, with URS 2008:5.3-32
HECA-2008-7	Multi-constituent (short-term habitation) site	CO_2 line	Recommended eligible under CEQA	Farmer 2008:5-7, 5-8, 6-1; HEI, with URS 2008:5.3-33
HECA-2008-11	Multi-constituent (short-term habitation) site	CO_2 line	Recommended eligible under CEQA	Farmer 2008:5-9, 6-1; HEI, with URS 2008:5.3-34, 5.3-35
HECA-12	Multi-constituent/short-term habitation site	CO_2 line	Recommended potential eligible under CEQA	Farmer 2008:5-10, 6-1; HEI, with URS 2008:5.3-34, 5.3-35, 5.3-46
Isolated Artifact 1	Isolated biface	CO_2 line	Ineligible under CEQA & NRHP	Stantec 2011:8
		Historic Archaeological Resources		
		HECA Project		
HECA 2010-2	Habitation and refuse scatter	Natural gas linear	Not evaluated	Hale and Laurie 2010; Hale et al. 2012; URS 2012e
		EOR Project		
CO2-2012-1	Refuse scatter	CO_2 processing facility	Not evaluated	In pending EOR report
		Multi-Component Archaeological Resources		
		HECA Project		
CA-KER-89/H (P-15-89) and KRM-IF-006	Midden (long-term habitation) site with human remains	Process water line	Not evaluated	
CA-KER-5356/H (P-15-6725) and P-15-7176	Lithic/historic refuse scatter and chert flake	Process water line	Not evaluated	Farmer 2008:Table 2-2; HEI, with URS 2008:Table 5.3-2
		EOR Project		
None				

Cultural Resources Table 9
Historic Built Environment Resources Eligibility: HECA

Resource Designation	Type & Description	Location	Project Element	NRHP/CRHR Status[27]	Recorded by
MR 1	Agricultural complex	Old Tracy Road	Natural gas line/Rail line	Ineligible	JRP 2012
MR 2 Buttonwillow-McKittrick Branch, Southern Pacific Railroad	Railroad	Parallel to SR 58 near Buttonwillow	Natural gas line/Rail line	Ineligible	JRP 2009, 2012
MR 3 A & B, C & D, PG&E, SCE Transmission Lines	Transmission lines	Various locations within PAA/APE, generally near East Side Canal	Natural gas line/Rail line	Ineligible	JRP 2012; URS 2010
MR 4	Residential property	6010 Buerkle Road	Natural gas line/Rail line	Ineligible	JRP 2009
MR 5 Quonset Hut	Agricultural property	35034 Stockdale Highway	Rail line	Ineligible	JRP 2012
MR 6 WPA-era Culvert Headwalls	Water conveyance	Dairy Road between Bellevue Road and Adohr Road	Natural gas line/Rail line	Ineligible	JRP 2012
MR 7 Adohr Farms	Residential farm complex	7307 Adohr Road	Natural gas line/Rail line/Controlled area	Ineligible	JRP 2009
MR 8 Palms Farm	Agricultural complex	7307 Adohr Road	Natural gas line/Project site/Construction laydown area	Ineligible	JRP 2009
MR 9 Adohr Farms	Residential farm complex	7345 Adohr Road	Natural gas line/Project site	Ineligible	JRP 2009
MR 10 Old Headquarters Weir	Weir/Bridge	Near Tupman and Adohr roads	Project Site/CO_2 line/Process water line	Eligible	JRP 2009, 2012
MR 11 California Aqueduct	Water conveyance	Parallel to West Side Canal	CO_2 line/Process water line	Eligible	Carey & Company 2007
MR 12	Residential property	6122 Tule Park Road	Potable water line/Transmission line	Ineligible	JRP 2009, 2012
MR 13 Tupman Water Plant	Water tank and pump house	Station Road	Potable water line/Transmission line	Ineligible	URS 2010
MR 14	Water	Various	Rail line /CO_2	Ineligible	JRP 2009,

[27] Eligibility for NRHP/CRHR as determined by the applicant's consultants and recorded on DPR 523 forms as part of URS 2012a.

Resource Designation	Type & Description	Location	Project Element	NRHP/CRHR Status[27]	Recorded by
BVWSD: Kern Valley Water Company Canal, West Side Canal, East Side Canal, Deep Wells Ditch, Depot Drain, Cass Ditch, Short Main Canal, Adohr/Palm Farm Levee and Outlet Canal.	conveyance	locations within PAA/APE	line/Potable water line/Transmission line		2012
MR 15 Tule Elk State Reserve	Wildlife reserve	8653 Station Road	Potable water line/Transmission line	Ineligible	URS 2010
2009 MR 4[28] Landing Strip and Hangar	Landing Strip and Hangar	Wasco Way	Natural gas line/Rail line	Ineligible	JRP 2009
KRM 001H[29]	Ditch and water gates		CO_2 Line	Unknown	Farmer 2008
KRM-010H	Historic Road		CO_2 Line	Recommended ineligible for CRHR	Farmer 2008:5-11, Table 5-1; HEI, with URS 2008:5.3-36, Table 5.3-4
Note: BVWSD = Buena Vista Water Storage District; PG&E = Pacific Gas and Electric Company; SCE = Southern California Edison; WPA = Works Progress Administration					

[28] This resource was submitted with the 2009 Amended AFC but was not resubmitted with the 2012 Amended AFC and is not indicated on the current project maps (JRP 2012:Map 2, Sheet 5). The resource lies partially within the current PAA/APE and therefore is included in staff's analysis.

[29] This resource was not included in the Amended AFC.

Cultural Resources Table 10
NPR-1/OEHI Built Environment Resources Eligibility

Resource Designation	Type	Project Element	Eligibility
NPR-1	Rural historic landscape important in local and state history for development of the petroleum industry. Unknown number of contributors subject to impacts.	CO_2 line and processing facility, EOR area	Not eligible
KRM-010H	Soil and gravel road	CO_2 line and processing facility, EOR area	Unknown
WW II Military Sites	Military earthworks and structures	CO_2 line and processing facility	Unknown
Check Dams	Surface water control structures	CO_2 line and processing facility	Unknown

This section discusses the methods and the results of each field inventory phase and interprets the resultant inventory relative to the cultural resources distribution models above to assess how well the inventory represents the archaeology of the project area. Descriptions of each cultural resource in the inventory, evaluations of the eligibility of each resource for inclusion in the CRHR and NRHP, assessments of project impacts on each known historical resource, consideration of and potential impacts on archaeological resources that may lie buried on the project site, and proposed mitigation measures for significant impacts may be found in the "California Register of Historical Resources Eligibility" and "Identification and Assessment of Direct Impacts on Built-Environment Resources and Proposed Mitigation" subsections below.

Geoarchaeology Study

Staff made requests to the applicant to provide information that would facilitate the assessment of the project's potential to encounter buried archaeological deposits during the construction, operation, and maintenance of the project. The response from the applicant was a geoarchaeology[30] study that, on the basis of background research, spatial analysis, and primary field research, provides a thorough discussion of the historical geomorphology of the project area and an assessment of the likely presence of buried archaeological deposits there.

Only one subsurface investigation has taken place within the PAA/APE. Five geotechnical borings were placed in the proposed project site. An archaeologist monitored these borings and examined the sediment that was removed. No cultural materials were observed. (URS 2009a:13–14; URS 2009c:5.3-29.)

Staff requested that the applicant conduct subsurface investigations in the form of geoarchaeological field sampling at the October Data Response Workshop as well as in Data Requests A151–152 and A195 (CEC 2012a:9–10; CEC 2012b:15–19). In addition,

[30] Geoarchaeology is a subdiscipline of archaeology that uses the techniques and approaches of earth sciences such as geology, geomorphology, sedimentology, pedology, and stratigraphy to identify, investigate, and interpret the history of the human use of present and former landscapes.

while evaluating the previous HECA AFC (08-AFC-8), a request for a fieldwork-based geoarchaeological study was the subject of six data requests since October 2009: DR 78 and 79 (October 12, 2009), DR 143 (January 13, 2010), Workshop DR 23 (April 12, 2010), and DR 172 and 173 (CEC 2009:19–20; CEC 2010c:6). In their October 2012 data response (URS 2012d:151-1 through 152-2), the applicant questions the need for further geoarchaeological analysis beyond what has already been submitted. Staff understands this argument to consist of five main points: 1) monitoring will provide sufficient protection for buried resources; 2) a geoarchaeological field study would cause a lengthy project delay; 3) focusing the monitoring effort is not necessary because monitoring is likely to be required across the entire PAA/APE; 4) trenching to find specific resources in areas determined to be especially sensitive is not necessary; and 5) a Cultural Resources Monitoring and Mitigation Plan (CRMMP) should be required as a condition of certification rather than a geoarchaeological field study. Staff addresses each of these points in turn, below.

First, staff does not agree that monitoring provides sufficient protection for buried resources during construction. Resources are often inadvertently damaged by heavy construction equipment during the discovery process, resulting in a substantial adverse change in the significance of the resource. If the resource is later determined to be a historical resource or unique archaeological resource, a significant effect to the environment under CEQA will have already occurred. In addition, construction schedules rarely allow sufficient time for the development of a resource specific research design or the careful exploration and documentation of the resource. The Energy Commission’s responsibility to identify measures to mitigate significant adverse change in the significance of a historic resource is best served by a CRMMP that is supported by facts specific to the project area. Although specific resources cannot be identified in advance, a well-designed and implemented geoarchaeological study will help identify the age and character of the sites that may be found. These project-specific facts can be used to develop the most appropriate research design and mitigation strategies possible.

Second, staff does not agree that conducting a geoarchaeological field study would cause a lengthy project delay. Staff established the need for this study in October of 2009. Although the project now has a new applicant, the cultural resources contractor (URS) remains the same. The current applicant has the advantage of knowing some of staff’s requirements in advance. Any concerns over the project schedule could have been proactively addressed by the applicant by submitting a geoarchaeological research plan with the Amended AFC.

Third, as discussed in detail above, staff maintains that a focused monitoring effort is essential for the appropriate evaluation and mitigation of any resource accidentally discovered during construction. A focused effort consists of the development of a CRMMP based on project specific information, provided in part by a geoarchaeological field study. Staff’s emphasis here is both on the knowledge and preparation of the monitoring team, as well as the intensity of the monitoring effort. While staff agrees that much of the PAA/APE is located in areas which have high sensitivity for buried resources, staff thinks it is inappropriate to make decisions about monitoring intensity in advance of data to support that decision. The updated geoarchaeological report provided in Hale et al. (2012) provides general information about the geoarchaeological context of the project vicinity based on the well-regarded work by Meyer et al. (2009) for Caltrans Districts 6 and 9. The applicant suggests that this initial step provides sufficient information about the project area. However, Meyer and his colleagues contradict this suggestion, concluding in their report that "depending on the nature and scope of a proposed project, areas of Moderately High through Very High potential will often require additional attention, perhaps leading to more focused geoarchaeological studies. These might include additional archival background research, field checking and examinations, subsurface explorations (e.g., trenching or coring), or more detailed modeling efforts" (Meyer et al. 2009:142). These are exactly the sorts of studies that staff has requested. Only one landform within the project area, the Quaternary alluvial fans (Qa) forming the lower elevations of the Elk Hills, investigated during Weber's (1998) study at CA-KER-3080, has been explored at the appropriate resolution. The other landforms still require additional attention.

Fourth, following Meyer et al. (2009), staff maintains that subsurface exploration may indeed be necessary for this project in areas where geoarchaeological field studies suggest that cultural resources may be present. When designed and conducted in an informed fashion, subsurface explorations help satisfy the requirement of Section 106 of the NHPA that "a reasonable and good faith effort to carry out appropriate identification efforts" is made (36 Code Fed. Regs., part 800.4(b)(1)). In their data response, the applicant points out that subsurface explorations will not result in a full inventory of the resources buried within the project area, and will not reduce the need for monitoring elsewhere. Staff agrees. Our intention is not to make a full inventory or reduce monitoring, but rather to make a good faith effort to identify buried resources in those landforms which are most likely to contain them.

Finally, staff does not agree that a CRMMP is a suitable substitute for a geoarchaeological field study. A CRMMP is a standard requirement for Energy Commission projects, and one of its primary roles is to ensure that the applicant is well prepared for inadvertent discoveries. A geoarchaeological field study is one of several project specific data sets that are required to develop a CRMMP which can adequately mitigate adverse changes in the significance of a historic resource. As such, a field study informs a CRMMP, but cannot be replaced by one.

In the April 2010 workshop, the applicant agreed to develop a plan for the combined geotechnical/ geoarchaeological investigations. In Data Request A195, staff requested that the applicant meet with staff to discuss the data needed to complete the staff impact analysis with respect to buried archaeological resources, so that the development and implementation of the plan can move forward. The applicant has since submitted a geoarchaeological work plan, which is presently under staff review (URS 2013d). Staff has provided comments and requested revisions to the plan; the applicant is presently addressing staff comments.

Intensive Pedestrian Surveys

The applicant undertook an intensive pedestrian cultural resources survey of the originally proposed project area to comply with the Energy Commission's siting regulations. The purpose of the survey was to provide information on the location and the character of the cultural resources that may lie on the surface of the project area.

The results contribute to the compilation of the cultural resources inventory of the proposed project area.

Methods

Consultants to the applicant conducted intensive pedestrian surveys of the PAA/APE between 2008 and 2012 (Farmer 2008; Hale and Laurie 2009, 2010, 2012; Hale et al. 2012; JRP 2009, 2012). Survey dates are shown in **Cultural Resources Table 11**.

Cultural Resources Table 11
Project Component Fieldwork Dates

Project Component	Fieldwork Dates	Reference
HECA Project Elements		
Project site	January 7–14, 2009	URS 2012b:A83-1
Controlled area	January 7–14, 2009	Mark R. Hale, personal communication 2012; Hale and Laurie 2009:34
Process water line	April 7–11, May 16–22, and June 28–30, 2008	Farmer 2008:4-1; HEI, with URS 2008:5.3-27
Transmission and potable water lines	April 4–5, 2010; January 18–19, 2011	URS 2012b:A83-1
BVWSD well field	December 8–10, 2009	URS 2012b:A83-1
Railroad and natural gas lines	July 28–30, 2010; February 28–29, April 3–4, September 18, 2012	Hale and Laurie 2012:Figure 1; URS 2012b:A83-1; URS 2012f:139-2, Figure A149-1, Sheet 5
Intersection improvements	Not surveyed as of March 2013	None
Electrical transmission switching station	April 5, 2010	Hale and Laurie 2013:9
EOR Project Elements		
CO_2 pipeline to processing facility	January 7–14, 2009 (portion in controlled area); 2011 (south of California Aqueduct)	Hale and Laurie 2009:34; Stantec 2011:1
CO_2 processing facility	Survey data unavailable as of June 2013	
Satellite gathering stations	Survey data unavailable as of June 2013	
Well sites (work-overs)	Survey data unavailable as of June 2013	
Well sites (new wells)	Survey data unavailable as of June 2013	
Oil producing lines	Survey data unavailable as of June 2013	
Injection lines, 16-inch	Survey data unavailable as of June 2013	
Injection lines, 12-inch	Survey data unavailable as of June 2013	
Injection lines, 10-inch	Survey data unavailable as of June 2013	
Injection lines, 6-inch	Survey data unavailable as of June 2013	
Injection lines, 4-inch	Survey data unavailable as of June 2013	
Gathering lines, 26-inch	Survey data unavailable as of June 2013	

Project Component	Fieldwork Dates	Reference
Gathering lines, 18-inch	Survey data unavailable as of June 2013	
Gathering lines, 16-inch	Survey data unavailable as of June 2013	
Gathering lines, 12-inch	Survey data unavailable as of June 2013	
Gathering lines, 10-inch	Survey data unavailable as of June 2013	
CO_2 trunk line, 12-inch	Survey data unavailable as of June 2013	
CO_2 trunk line, 6-inch	Survey data unavailable as of June 2013	
CO_2 trunk line, 4-inch	Survey data unavailable as of June 2013	
Oil tie-in lines, 8-inch	Survey data unavailable as of June 2013	
Natural gas lines, 3-inch	Survey data unavailable as of June 2013	
Water lines, laterals, 10-inch	Survey data unavailable as of June 2013	
Fuel gas lines, 6-inch	Survey data unavailable as of June 2013	
Residue gas line, 6-inch	Survey data unavailable as of June 2013	
Nitrogen line, 8-inch	Survey data unavailable as of June 2013	
Propane line	Survey data unavailable as of June 2013	

Methods: HECA—2008

Survey of the proposed process water line was accomplished by the survey crew walking parallel north–south or east–west transects spaced 50 feet apart. Survey transects were narrowed to 15 feet upon discovery of archaeological materials in a given area. (Farmer 2008:4-1.) Ground surface visibility in the proposed process water line's corridor was about 50 percent (Hale and Laurie 2009:36).

Methods: HECA—2009–2012

The project site and controlled area was surveyed by walking alternating, parallel transects spaced 50–65 feet between surveyors. The survey area included a 200-feet buffer surrounding the project site and controlled area, as required at Title 20, California Code of Regulations, section 1704(b)(2), Appendix B(g)(2)(C). Ground surface visibility was generally greater than 80 percent in the project site and controlled area. Where nonagricultural vegetation obscured the ground surface, the survey crew cleared 8-inch-by-8-inch squares using hand tools or footwear. (Hale and Laurie 2009:34, 36; URS 2012a:5.3-21, 5.3-22.) These scrapes were employed when surface visibility was less than 50–60 percent, and were made at 50–100-feet intervals across the vegetated portion of the survey area (URS 2012b:A83-2).

The proposed linear HECA facilities were surveyed by walking parallel transects spaced 50–65 feet between surveyors. The survey corridor for proposed linear facilities also included a 50-feet buffer from the linear routes, per Title 20, California Code of

Regulations, section 1704(b)(2), Appendix B(g)(2)(C). Ground surface visibility along the proposed linears was generally 50 percent or better. Surface scrapes were employed as described in the previous paragraph. (Hale and Laurie 2010:3-9; Hale et al. 2012:33,37; URS 2012a:5.3-21, 5.3-22; URS 2012b:A83-2).

A portion of the proposed natural gas pipeline corridor along SR 58 just west of I-5, inaccessible during earlier survey efforts, was examined by walking transects spaced 33–50 feet apart. The surveyed area included a 50-feet buffer from the proposed corridor. Ground surface visibility was excellent (75–100 percent). In addition, the proposed railroad laydown area and a 200-feet buffer were surveyed using identical methods. The southern portion of this survey area had fair ground surface visibility (25–50 percent) owing to alfalfa row crops. Surface scrapes were not conducted so that damage would not occur to the crops. (Hale and Laurie 2012:9–10, Figure 1).

The proposed electrical transmission switching station was surveyed by walking parallel transects spaced 33–50 feet apart. The surveyed area included a 200-feet buffer surrounding the proposed facility site. Ground surface visibility was good to excellent (50–100 percent) across the survey area, being impeded by the presence of alfalfa plants. (Hale and Laurie 2013:8–9:Figure 1).

Archaeological sites recorded as a result of the surveys were assigned temporary numbers (e.g., HECA-1). The survey crew plotted site locations onto 7.5-minute topographic quadrangle maps with the assistance of a global positioning system (GPS) receiver. Site recordation consisted of mapping and completion of appropriate Department of Parks and Recreation (DPR) 523 forms. (Hale and Laurie 2013:9; Hale et al. 2012:37; URS 2012a:5.3-21).

Methods: EOR

Portions of the EOR project elements were surveyed in 2008, 2009, and 2011 (Farmer 2008; Hale and Laurie 2009; Hale et al. 2012; Stantec 2011). The only recently surveyed EOR project element is the proposed CO_2 pipeline from the project site to the proposed CO_2 processing facility in Elk Hills. The portion of CO_2 pipeline north of the California Aqueduct was effectively surveyed during the cultural resources inventory of the controlled area (Hale and Laurie 2009; Hale et al. 2012). The survey methods are discussed in the previous section, “Methods: HECA—2009–2012”.

The portion of CO_2 pipeline south of the California Aqueduct was surveyed in part by Farmer (2008:4-1) on March 2–7 and June 28–30, 2008, and in its entirety on February 23–24, 2011 (Stantec 2011:8). Survey methods in 2008 entailed walking systematic, parallel transects as described in the section entitled, “Methods: HECA—2008”. Stantec (2011:8) surveyed the proposed CO_2 pipeline by walking systematic parallel transects spaced 50 ft between surveyors across a 150-feet-wide corridor. Dense grasses and shrubs reduced ground surface visibility to 10–20 percent (Stantec 2011:1). Efforts were not expended to improve the ground surface visibility.

Results

Consultants to the applicant identified 31 new archaeological resources in the PAA/APE. Of these, 13 are archaeological sites and 18 are isolated archaeological finds. Of the archaeological sites, eleven are prehistoric sites and two are historic. The isolates are all prehistoric finds.

As of the date of this PSA/DEIS, several portions of the PAA/APE have not been surveyed for the presence of cultural resources (see **Cultural Resources Table 11** above). Until such a time as the full PAA/APE is surveyed, staff cannot completely analyze the potential impacts of the proposed project on cultural resources. The applicant has informed staff that they will complete pedestrian surveys and report on their findings in time to inform staff's FSA/FEIS for the proposed project.

Historic Built Environment Surveys

JRP (2009, 2012) conducted a historic built environment survey on February 2 and March 9–12, 2009, as well as April 2010, January 2011, and February and March 2012. A total of 21 historic built environment resources were identified, two of which were previously recorded.

Interpretation of Results

The total cultural resources inventory for the project area of analysis includes 23 built-environment resources and 31 archaeological resources (see **Cultural Resources Tables 8–10**). The comparison and interpretation of the results of the efforts to develop the project inventory are made here, relative to the cultural resources distribution models above, to assess the reliability of the results.

Model of Prehistoric Archaeological Resources

Although all of the required pedestrian surveys are not complete, the results of the efforts to identify prehistoric archaeological resources in the PAA/APE conform well in some ways and poorly in others to the predictions of the above model for this resource class. The highest density of sites was expected near the boundaries of the Buena Vista Slough. Fourteen of the 15 sites with prehistoric components were identified in this area, along the proposed process water line, controlled area, and CO_2 line. Also as predicted these sites were initially categorized as midden (long term habitation) sites, multi-constituent (short term habitation) sites, and lithic scatters. In contrast, a very low density of prehistoric sites was found on the valley floor along the proposed transmission, gas, and rail lines. These findings conflict with the expectations of the model which predicted a low to moderate probability of surface archaeological sites in this area. The effectiveness of the model for this region may have been hampered by the small number of previous projects upon which the model is based. Alternatively, years of agricultural activities may have destroyed the majority of prehistoric sites in this portion of the PAA/APE. Finally, the pedestrian survey of the EOR area is incomplete, and so it is uncertain if the model for the Elk Hills will be effective.

The prehistoric sites identified within the PAA/APE require evaluative test-excavation to determine whether the sites retain the potential to yield information important to prehistory and therefore qualify as historic properties, historical resources, or unique archaeological resources. Staff requested this primary field data in the form of evaluative test excavation. Until staff receives this information, an interpretation of the spatial patterning of prehistoric archaeological sites across the PAA/APE can only be provisional.

Model of Historic Archaeological Resources

Despite the fact that the entire PAA/APE has not yet been surveyed for the presence of historic archaeological resources, sufficient information is available for comparison with expectations about the types and distribution of such resources in the PAA/APE. A total of four historic archaeological resources and archaeological sites with historic materials have been identified in the PAA/APE (**Cultural Resources Table 8**). Additionally, historic archaeological resources are likely associated with four historic built environment resources identified in the EOR area of the PAA/APE (**Cultural Resources Table 10**). The results of the cultural resources inventory generally corroborate the model of historic archaeological resources presented earlier in this PSA/DEIS.

With regard to Euroamerican historic archaeological resources, HECA-2010-2 represents the expected collection of early twentieth-century farmhouse remnants. The structural materials and household goods found at HECA-2010-2 are typical of such sites, and the site is located at a crossroads where historic maps document buildings and structures since the late 1920s (see HECA-2010-2 under “HECA Project Elements/Historic Archaeological Resources” below). Expectations for historic archaeology in the EOR area was partially met as well, in that site CO2-2012-1 consists primarily of structural and industrial discards, as befits an active oil field (see CO2-2012-1 under “EOR Project Elements/Historic Archaeological Resources” below). The historic artifacts identified at CA-KER-89/H and CA-KER-5356/H are commensurate with expectations for local resources. The only surprising result of the historic archaeological inventory of the HECA portion of the PAA/APE is the small number of historic archaeological resources identified. This appears to be a consequence of wide-ranging land modifications to support agriculture and salvage or demolition of older, failing structures. Staff cannot presently assess the distribution of historic archaeological sites in the EOR portion of the PAA/APE because survey results are unavailable for the bulk of the area.

Reliability of Cultural Resources Inventory

Staff finds, on the basis of the above analysis, that the cultural resources inventory for the PAA/APE is not yet a reliable body of information on which the Siting Committee can, in part, base its decision on the potential for the construction, operation, and maintenance of the proposed project to have a significant effect on the environment, as such an effect would relate to cultural resources. As will be seen in this analysis, the cultural resources inventory currently leaves a number of issues unresolved: the significance status of certain archaeological resources is undetermined, the potential for buried archaeological deposits to be present in the PAA/APE has not been adequately assessed, and inventory of the proposed EOR elements has not been reported to the Energy Commission. Staff understands that the applicant is working to fill these data gaps and expects to have the necessary information for completion of the FSA/FEIS.

Cultural Resource Descriptions and Significance Evaluations

HECA Project Elements

Prehistoric Archaeological Resources

At present, staff is able to conclude that a total of 18 prehistoric archaeological resources would be subject to direct impacts from the proposed project elements. Insufficient data are available to staff, however, to determine whether these archaeological sites are significant cultural resources (historic properties, historical resources, or unique archeological resources). Because Section 106 and CEQA require that impacts be evaluated only for significant cultural resources, staff needs the applicant to conduct significance evaluations of these archaeological sites in order to complete this impact analysis.

CA-KER-171

CA-KER-171 is a prehistoric site of unknown size located in the proposed process water well field and process water line. It was originally recorded as an “occupation site” by Frank Latta in 1950. A relative site location is plotted on the Lokern 7.5-minute USGS quadrangle; however, no other information about the site was provided. (Hale et al. 2012:39.) This location has been disturbed by various agricultural activities and construction of the West Side Canal. CA-KER-171 was not relocated by the applicant. However, a lithic scatter (HECA 2009-9) was identified approximately 900 feet to the south, raising the possibility that CA-KER-171 may have been misplotted.

The more particular physical context for site CA-KER-171, extrapolating information from **Cultural Resources Figure 1** to the location of the site, appears to be within the Buena Vista Slough deposits of the Qb unit. The possibility of buried cultural resources within the slough deposits is expected to be high.

The site description suggests that the site can be classified as either a midden (long-term habitation) or a multi-constituent (short-term habitation) site. The applicant has not conducted the fieldwork required to resolve the confusion over the location of CA-KER-171 or evaluate the site to determine whether it qualifies as a historical resource, unique archaeological resource, or historic property. Staff requested that the applicant acquire the necessary data by conducting an archaeological test excavation at the mapped location of CA-KER-171 (Data Requests A192–194) or by demonstrating that the applicant could avoid damaging CA-KER-171 (Data Request A147) (CEC 2012a:7–9; CEC 2012b:13–14). In the applicant’s response to Data Request A147, they indicate that the vicinity of CA-KER-171 is covered by 1.4–4.1 feet of fill dirt. Because the proposed pipeline would be installed in a trench 5 feet deep, there is insufficient fill in the vicinity of CA-KER-171 to protect the site from damage. The applicant, however, proposes an avoidance measure to protect CA-KER-171 (see “Direct/Indirect Impacts and Mitigation”). (URS 2013b.) Staff considers CA-KER-171 to be a historical resource under CEQA and a historic property under Section 106 of the NHPA, for the purposes of this project only.

CA-KER-179

CA-KER-179 is a site located along the proposed process water line. It has been described as a "burial mound," suggesting that it might be a midden (long-term habitation) site. However, no additional information was provided (Hale et al. 2012:43; URS 2012a:5.3-30, 5.3-31). The site was not relocated by the applicant, but four isolates (BS-IF-02, -03, -04, and -05) were found near CA-KER-179 along the proposed process water line. These materials consist of three chert flakes, two chert tools, and one mussel shell. (Farmer 2008:Table 5-1).

The more particular physical context for site CA-KER-179, extrapolating information from **Cultural Resources Figure 1** to the location of the site, appears to be within the Buena Vista Slough deposits of the Qb unit. The possibility of buried cultural resources within the slough deposits is expected to be high.

Given the site record, the recent isolated finds, and the possibility of intact buried deposits, a site may be present in the vicinity. The applicant has not conducted the fieldwork required to resolve the confusion over the location of CA-KER-179 or evaluate the site sufficiently to determine whether the site constitutes a historical resource, unique archaeological resource, or historic property. Staff requested that the applicant acquire the necessary data by conducting archaeological test excavation at the mapped location of CA-KER-179 (Data Requests A192–194) or demonstrate that the applicant could avoid damaging CA-KER-179 (Data Request A147) (CEC 2012a:7–9; CEC 2012b:13–14). In the applicant's response to Data Request A147, they indicate that the vicinity of CA-KER-179 is covered by 2.2–2.8 feet of fill dirt. Because the proposed pipeline would be installed in a trench 5 feet deep, there is insufficient fill in the vicinity of CA-KER-171 to protect the site from damage. The applicant, however, proposes an avoidance measure to protect CA-KER-171 (see "Direct/Indirect Impacts and Mitigation"). (URS 2013b.) Staff considers CA-KER-171 to be a historical resource under CEQA and a historic property under Section 106 of the NHPA, for the purposes of this project only.

CA-KER-2485 (P-15-2485) and BS-IF-003

CA-KER-2485 an archaeological deposit approximately 0.6 acre in area. The surface component of the site measures approximately 150 feet from north to south and 150 feet from east to west. (Jackson 1989:1.) It is located along the proposed process water line, primarily on the southwest side of the West Side Canal. Vegetation at the site consists of desert scrub. The soil is light brown sand with intermittent clay deposits. Modern disturbance, including seasonal flooding, modern trash disposal, and bulldozer activity, is extensive. The site was not relocated by the applicant. However, the 1989 site form describes the site as consisting of lithic debitage, lithic tools, and groundstone fragments (Hale et al. 2012:43; URS 2012a:5.3-31). Two unusual, very large chert projectile points were also collected from this site. The point types were not specified, but were noted to be extremely rare in the Southern San Joaquin Valley. (Jackson 1989.) Further, the presence of a piece of lithic debitage (BS-IF-003) on the northeast side of the West Side Canal (Farmer 2008:Table 5-1) suggests that the canal cuts through CA-KER-2485 and that plowing east of the West Side Canal may have obscured most surface evidence of the site in the PAA/APE.

The more particular physical context for site CA-KER-2485, extrapolating information from **Cultural Resources Figure 1** to the location of the site, appears to be within the Buena Vista Slough deposits of the Qb unit. The possibility of buried cultural resources within the slough deposits is expected to be high.

The site description suggests that CA-KER-2485 can be classified as a multi-constituent (short-term habitation) site. The applicant has not conducted the fieldwork required to determine if CA-KER-2485 extends into the PAA/APE or constitutes a historical resource, unique archaeological resource, or historic property. Staff requested that the applicant acquire the necessary data by conducting archaeological test excavation at the mapped location of CA-KER-2485 (Data Requests A192–194) or demonstrate that the applicant could avoid damaging the site (Data Request A147) (CEC 2012a:7–9; CEC 2012b:13–14). In the applicant's response to Data Request A147, they state that CA-KER-2485 is outside of the PAA/APE, BS-IF-003 is merely an isolated find, neither resource warrants further treatment (URS 2013b). Staff finds this view, in light of the information provided in the first paragraph of this subsection, overly simplistic. Considering that these two separately recorded archaeological resources are adjacent to the same water conveyance feature directly across from one another, an assertion that the two resources are not elements of the same resource without any factual basis of support other than the results of surface finds made in separate cultural resource surveys seems an inadequate foundation on which to agree with the applicant's findings. Accordingly, staff requests that the applicant either demonstrate that BS-IF-003 is a find unrelated to CA-KER-2485 by conducting a test excavation, or place a sufficient quantity of fill at BS-IF-003's location to preclude construction-related damage, as the applicant proposes at CA-KER-171 and CA-KER-179. Until then, staff assumes that CA-KER-2485 and BS-IF-003 is a historical resource under CEQA and a historic property under Section 106 of the NHPA.

CA-KER-3108 (P-15-3108)

CA-KER-3108 is an archaeological deposit approximately 0.9 acre in area. The surface component of the site measures approximately 150 feet from north to south and 225 feet from east to west. It was originally recorded as a low density lithic scatter of chert and obsidian flakes with several possible pieces of groundstone. (Everson 1991:1.) It is located along the proposed natural gas supply line. The Southern Pacific Railroad tracks cut through the northern half of the site. (Hale et al. 2012:39.) The vegetation at the site consists of saltbush, thistle, and assorted grasses. Soil on the site is described as fine grained silt. Modern disturbance includes the construction of the SR 58 and the railroad tracks. (Everson 1991.) The site was not relocated by the applicant.

The more particular physical context for site CA-KER-3108, extrapolating information from **Cultural Resources Figure 1** to the location of the site, appears to be within the Buttonwillow Ridge of the Qoa unit. Staff considers the Qoa unit to have a low to moderate potential for archaeological materials on its upper surface, while the possibility for buried deposits is expected to be very low.

The site was first recorded in 1991 as a low density artifact scatter. When it was revisited in 1992, only a single possible piece of groundstone was found. During the survey for the current project the applicant was unable to relocate the site, suggesting the possibility that the site was misplotted (URS 2012a:5.3-27, 5.3-28). The applicant has not conducted the fieldwork required to determine if a buried archaeological site is present at this location. Without primary field data on the presence of a subsurface component for the site, staff cannot evaluate whether CA-KER-3108 constitutes a historical resource, unique archaeological resource, or historic property.

Staff requested that the applicant conduct presence/absence and test excavation at the location of CA-KER-3108 (Data Requests A192–194) (CEC 2012a:7–9). The applicant's response to Data Requests A192–194 states that they intend to avoid CA-KER-3108, they do not have access or permission to excavate the site, and a subsurface testing plan is not warranted currently. The applicant also points out that two survey efforts after the initial discovery of CA-KER-3108 failed to turn up evidence of the site as support for dispensing with conducting a test excavation at the site location. The applicant identified discrepancies between the reported site description and map coordinates, which they see as casting doubt on whether CA-KER-3108 was ever at the mapped location. (URS 2013a:A192-2, A192-3).

Hale et al. (2012:5.3-27, 5.3-28) note that the mapping (Universal Transverse Mercator, or UTM) coordinates on the original CA-KER-3108 site record form corresponds to a location about 755 ft southeast of the location plotted on the Buttonwillow 7.5-minute USGS topographic map. Staff has examined this site record as well as the archaeological survey report that generated the record, and disagrees with this suggestion. UTM coordinates for a given location are calculated in one of two ways: (1) manually, by reading and measuring coordinates based on a map plot directly from the map, or (2) by taking coordinates with a GPS receiver. Staff believes it is clear that the UTM coordinates for CA-KER-3108 were calculated based on a field-map plot that accurately reflects the site's location, not from a GPS reading taken at another place. First, CA-KER-3801 was identified in 1991 (Everson 1991:1), a time when the use of GPS equipment in archaeological surveys was uncommon. Second, the survey crew—led by Everson and others—did not use a GPS receiver to record site locations; rather, they were "plotted on the appropriate USGS 7.5' topographic quadrangles." (Parr and Osborne 1992:1, 51–52.) Additionally, the site sketch map ties the site location to a dirt road adjacent to SR 58 and the Southern Pacific Railroad tracks (Everson 1991:3); a location 755 feet to the southeast would not place CA-KER-3108 near the railroad tracks or SR 58. Therefore, the method of determining UTM coordinates was measuring from the map plot, and the numbers were simply miscalculated when reported on the site record form. Furthermore, it should be noted that Parr and Osborne (1992:52) reported that numerous archaeological sites that were identified during the initial survey and revisited for additional work were found in some cases to exhibit fewer artifacts than were initially observed (as with CA-KER-3108). In other cases, rain or wind had exposed previously unidentified artifacts at archaeological sites. Staff finds that the weight of evidence and CA-KER-3108's proximity to SR 58 places the site squarely within the natural gas line portion of the PAA/APE. This site has not been test excavated and evaluated for qualification as a historical resource, unique archaeological resource, or historic property under CEQA or Section 106 of the NHPA. Staff again requests that the applicant address Data Requests A192–194 (CEC 2012a:7–9) or demonstrate how the applicant intends to avoid damaging CA-KER-3108, considering its location within the PAA/APE. In the interim, staff assumes that CA-KER-3108 is a historical resource under CEQA and a historic property for Section 106 purposes.

HECA-2008-1 (JM-BVWD-1)

HECA-2008-1 (originally recorded as JM-BVWD-1) is a buried prehistoric site which would be directly impacted by the proposed process water line. Construction and upkeep of the West Side Canal has cut into this deeply stratified site. Prehistoric artifacts are evident 6 feet below the modern ground surface and extend 515 feet along the canal. The size, shape, and overall depth of the site are undetermined. However, the presence of the artifacts suggests that the remainder of the site may be preserved intact well below the levels of modern agricultural disturbances. In modern times vegetation in the vicinity of the site consists of salt-bush scrub to the west and wheat fields to the east. The site sediment type is unspecified. The sparse scatter of artifacts includes lithic debitage, a projectile point tip fragment, and three pieces of burnt faunal bone. The debitage comprises Monterey and Franciscan chert. (Hale et al. 2012:40, Figure 1, Sheet 2; URS 2012a:5.3-28).

The more particular physical context for site HECA-2008-1, extrapolating information from **Cultural Resources Figure 1** to the location of the site, appears to be within the Buena Vista Slough deposits of the Qb unit. The presence of this site demonstrates the high possibility of buried cultural resources within portions of the PAA/APE situated within slough deposits.

The Amended AFC offers no temporal association or functional interpretation for the site (Hale et al. 2012:40; URS 2012a:5.3-28). However, the lack of groundstone and midden soil suggests this site may have been a multi-constituent (short-term habitation) site. The applicant has not conducted the fieldwork required to gather data for site eligibility determinations, and no eligibility recommendation was provided. Without primary field data on the subsurface component of HECA-2008-1, staff cannot determine whether the archaeological site constitutes a historical resource, unique archaeological resource, or historic property. Staff requested this primary field data in Data Requests A192–194 (CEC 2012a:7–9), but has not yet received this information. In the absence of this information, staff assumes that HECA-2008-1 is a historical resource and historic property for CEQA and Section 106 purposes, respectively.

HECA-2009-2

HECA-2009-2 is a prehistoric archaeological deposit approximately 3496 square feet in area. The surface component of the site measures approximately 76 feet north–south and 46 feet east–west. It is located along the proposed CO_2 line. The site is located adjacent to a flat agricultural field on the eastern slope of a berm that parallels the Outlet Canal. There is no native vegetation present at the site. The soil is a light brown silty loam with pea-size gravels. Modern disturbances in the site vicinity include the grading of two dirt roads, and construction of the Outlet and West Side canals. The site consists of a low density (less than one artifact/11 square feet) scatter of lithic artifacts including two chert bifaces, a steatite groundstone fragment, and three yellow-brown cryptocrystalline silicate (CCS) reduction flakes. The artifacts were encountered primarily within the road berm and within the adjacent dirt road. (Hale et al. 2012:40; URS 2012a:5.3-28.)

The more particular physical context for site HECA-2009-2, extrapolating information from **Cultural Resources Figure 1** to the location of the site, appears to be within the

Buena Vista Slough deposits of the Qb unit. The possibility of buried cultural resources within the slough deposits is expected to be high.

The Amended AFC does not suggest temporal associations or functional interpretations for the site (Hale et al. 2012:40; URS 2012a:5.3-28). However, the lack of groundstone and freshwater mussel shell indicates that this site was a special function site that can be classified as a lithic scatter. In addition the presence of steatite suggests the site may date to the Emergent Period (850 B.P.–Historic). The applicant has not conducted the fieldwork required to gather data for site eligibility determinations, and no eligibility recommendation was provided. Without primary field data on the presence of a subsurface component for the site, staff cannot determine whether HECA-2009-2 qualifies as a historical resource, unique archaeological resource, or historic property. Staff requested these primary field data in Data Requests A192–194 (CEC 2012a:7–9), but has not yet received this information. Staff assumes for the purposes of the present analysis that HECA-2009-2 is a historical resource under CEQA and a historic property for the purposes of Section 106 of the NHPA.

HECA-2009-9

HECA-2009-9 is a prehistoric archaeological deposit approximately 1.5 acres in area. The surface component of the site measures approximately 246 feet north–south and 262 feet east–west. It is located along the proposed process water line and process water well field, northeast of the West Side Canal. The site is situated in an agricultural field; no native vegetation is present at the site or its vicinity. The present site surface is composed of dark brown clay loam with pea size gravels. Further details about the site surface are unspecified. This site consists of a low density (less than one artifact/11 square feet) scatter of lithic debris, including a CCS core and approximately 25 CCS reduction flakes. Modern disturbances in the site vicinity include the construction of the West Side Canal, two dirt roads, and the development of an orchard (Hale et al. 2012:40–41; URS 2012a:5.3-28, 5.3-29).

The more particular physical context for site HECA-2009-9, extrapolating information from **Cultural Resources Figure 1** to the location of the site, appears to be within the Buena Vista Slough deposits of the Qb unit. The possibility of buried cultural resources within the slough deposits is expected to be high.

The Amended AFC does not suggest temporal associations or functional interpretations for the HECA-2009-9. However, this site can be classified as a lithic scatter, which may have served a special function. The applicant has not conducted the fieldwork required to gather data for a site significance evaluation, and no significance recommendation was provided. Without primary field data on the presence of a subsurface component for the site, staff cannot determine whether HECA-2009-9 qualifies as a historical resource, unique archaeological resource, or historic property. Staff requested this primary field data in Data Requests A192–194 (CEC 2012a:7–9), but has not yet received this information. Therefore staff was unable, on the basis of the information provided, to determine if HECA-2009-9 is eligible for the CRHR or qualifies as a historic property for Section 106 purposes. In the absence of this information, staff assumes that HECA-2009-9 qualifies both as a historical resource and historic property.

HECA-2009-10

HECA-2009-10 is an oblong prehistoric archaeological deposit approximately 17 acres in area. The surface component of the site measures approximately 591 feet north–south and 1247 feet east–west. It is located along the proposed process water line and process water well field, northeast of the West Side Canal. The site is situated in an agricultural field; no native vegetation is present at the site or its vicinity. The present site surface is composed of dark brown clay loam with pea size gravels. Further details about the site surface are unspecified. This site consists of a single artifact concentration surrounded by a low density (less than one artifact/11 square feet) scatter of lithic debris. Both the concentration and the scatter consist entirely of debitage, including approximately 100 CCS reduction flakes. Besides plowing, other modern disturbances in the site vicinity include the construction of the West Side Canal, a graded dirt road, and other associated agricultural activities. (Hale et al. 2012:41, Figure 1, Sheet 1; URS 2012a:5.3-29).

The more particular physical context for site HECA-2009-10, extrapolating information from **Cultural Resources Figure 1** to the location of the site, appears to be within the Buena Vista Slough deposits of the Qb unit. The possibility of buried cultural resources within the slough deposits is expected to be high.

The Amended AFC does not suggest temporal associations or functional interpretations for the HECA-2009-10. However, this site can be classified as a lithic scatter which may have served a special function. The applicant has not conducted the fieldwork required to gather data for a site significance evaluation, and does not provide a significance recommendation. Without primary field data on the presence of a subsurface component for the site, staff cannot determine whether HECA-2009-10 qualifies as a historical resource, unique archaeological resource, or historic property. Staff requested this primary field data in Data Requests A192–194 (CEC 2012a:7–9), but has not received it. For the purposes of this analysis, staff assumes that HECA-2009-10 is a historical resource under CEQA and a historic property for Section 106 purposes.

HECA-2010-1

The applicant identified archaeological site HECA-2010-1 in the 200-feet buffer area defined for the proposed electrical switching station. The applicant's report on the proposed HECA transmission upgrades describes HECA-2010-1 as a “very light scatter of lithic material” and a “lithic scatter.” (URS 2013a:3-4, Table 3.3-1.) The confidential cultural resources survey report for the proposed transmission upgrades contains additional information on the site. HECA-2010-1 consists of four artifacts distributed over a 160-feet-by-66-feet area. The artifacts consist of a CCS flake, a chert flake, a basalt flake, and an obsidian biface fragment. Disturbances in the area include construction of the Midway–Wheeler Ridge Transmission Line and grading for road construction. (Hale and Laurie 2013:10.)

The applicant found no evidence that HECA-2010-1 extends into the proposed electrical switching yard, and ground surface visibility was suitable at the time of survey to make this determination. The applicant concludes that construction of the proposed project would not affect HECA-2010-1 if temporary barriers are put in place to keep construction personnel and equipment off the site. (URS 2013a:3-4, 3-5.) The applicant did not evaluate HECA-2010-1 for significance under CEQA or Section 106 of the NHPA and did not propose further work at the site.

Staff is concerned, however, that the applicant's efforts to describe HECA-2010-1 fall short of what is needed for staff to determine if the site qualifies as a historical resource, unique archaeological resource, or historic property. The applicant demonstrates clearly that the proposed project would not damage the surface expression of HECA-2010-1, but does not address the potential for subsurface archaeological deposits to extend into the footprint of the proposed electrical switching station, neither by test excavation to determine the presence or absence of subsurface archaeological deposits within the recorded site boundaries, nor by presence/absence excavation in the adjacent proposed switching station footprint. The applicant hypothesizes that the site vicinity has low potential for buried archaeological deposits because the area is situated on a Pleistocene-aged landform that developed prior to human habitation of the project vicinity. The applicant further states that the vicinity of HECA-2010-1 consists predominantly of Garces series soils, which the applicant states previous researchers have radiocarbon-dated to the latest Pleistocene/Early Holocene. Accordingly, the applicant views this landform as having been stable to slightly erosional since the latest Pleistocene and therefore is unlikely to harbor buried archaeological resources. (Hale and Laurie 2013:8.)

The argument presented above has intuitive appeal, but suffers from errors of fact. Staff agrees that the landform on which both HECA-2010-1 and the proposed electrical switching station—Wheeler Ridge—was formed in the latest Pleistocene (see Meyer et al. 2009:51). That the vicinity of HECA-2010-1 is predominantly on Garces series soils, however, is false. The proposed electrical switching station and HECA-2010-1 are located on Buttonwillow clay, as depicted in the applicant's Transmission Upgrades report (URS 2013a:Figure 3.9-1). Flanking the proposed electrical switching station to the north and south are Kimberlina fine sandy loam and Lokern clay, drained, respectively; Garces series soils are located a little beyond the Kimberlina soil units. (URS 2013a:Figure 3.9-1.) The presence of Kimberlina soil units in close proximity to HECA-2010-1 is interesting because Meyer et al. (2009:75) reports Late Holocene radiocarbon dates from this soil unit. In fact, archaeological site CA-KER-3085 in the Elk Hills is located atop a buried Kimberlina soil unit and excavations at this site yielded radiocarbon dates of 1265 cal B.P. from the buried soil (3.9–4.1 feet below ground surface) and 720 ± 50 B.P. at 0.5–0.6 feet below ground surface (Culleton 2006:Table 4; Meyer et al. 2009:77). Lacking radiocarbon dates for the Buttonwillow clay and Lokern soil series in the vicinity of HECA-2010-1, and the recent dates obtained from Kimberlina soils, present an unfavorable situation for assuming that surface and near-surface soils on Wheeler Ridge are of latest Pleistocene age. It appears to staff that Kimberlina soils and perhaps Buttonwillow soils are potentially Late Holocene in age and suitable for harboring subsurface or buried archaeological resources. Without the information that would be supplied by test excavation at HECA-2010-1 or presence/absence excavation in the proposed electrical switching station, staff assumes that subsurface or buried archaeological materials extend into the proposed construction area. HECA-2010-1 and any associated materials in the proposed switching station footprint are assumed to constitute a historical resource under CEQA and a historic property under Section 106 of the NHPA. Prior to completion of the FSA/FEIS, staff requests that the applicant prepare a work plan and conduct a presence/absence excavation in the proposed electrical switching station footprint so that staff has a factual basis for establishing the proposed project's likelihood of damaging archaeological resources at this location. The applicant can conduct this excavation in tandem with their proposed geoarchaeological investigation (see URS 2013d).

BS-IF-004

BS-IF-004 was identified along the proposed process water line and recorded as an isolate. The "isolate" consists of a small brow chert flake fragment, bifacially shaped brown chert chopper, and three large freshwater mussel shell fragments. The chopper was found in the bottom of the West Side Canal with the mussel shell in a gravel lens. The flake was located on the dirt access road flanking the canal. (Farmer 2008:Table 5-1; McNutt and Shaw 2008:1.) Staff disagrees with Farmer's (2008:Table 5-1) classification of BS-IF-004 as an isolate. OHP (1989:2) defines a site as consisting of at least three associated artifacts or a single feature. The apparent association between the chopper and freshwater mussel, coupled with the nearby flake fragment, is clearly more than three associated artifacts. Staff therefore considers BS-IF-004 to be an archaeological site and disagrees with the applicant that no further work at this location is warranted. The applicant has not conducted the fieldwork required to gather data for a site significance evaluation for BS-IF-004. Without primary field data on the presence or absence of a subsurface component for the site, staff cannot determine whether the site qualifies as a historical resource, unique archaeological resource, or historic property. For the purposes of this analysis, staff assumes that BS-IF-004 is a historical resource and historic property.

KRM-IF-003

KRM-IF-003 consists of one chert flake and two pieces of chert shatter, all the byproducts of stone-tool manufacture (McLean and Mattiuissi 2008:1). The resource is situated along the proposed process water line about 200 ft from site CA-KER-179. Following OHP's (1989:2) definition of a site, staff classifies KRM-IF-003 as a site, rather than as an isolate as Farmer (2008:Table 5-1) does. The applicant has not conducted the fieldwork required to gather data for a site significance evaluation for KRM-IF-003. Without primary field data on the presence or absence of a subsurface component for the site, staff cannot determine whether the site qualifies as a historical resource, unique archaeological resource, or historic property. For the purposes of this analysis, staff assumes that BS-IF-004 is a historical resource and historic property.

CA-KER-5401 (P-15-6776)

P-15-6776 is a prehistoric archaeological deposit approximately 17 acres in area. The surface component of the site measures approximately 702 feet north–south and 1066 feet east–west. It is located along the proposed CO_2 pipeline south of the West Side Canal and the California Aqueduct. The site area is a gently sloping alluvial piedmont with north aspect and open exposure. The setting provides an overview of the former network of sloughs running along the western margin of the Central Valley. The site has been disturbed by agriculture, livestock grazing, heavy equipment and construction of the California Aqueduct. Currently the site is covered with very sparse low grasses. The present site surface is composed of loosely compacted silty sand with limestone and sandstone inclusions (Farmer 2008:5-20).

The site was originally recorded as an isolated bowl mortar and associated freshwater mussel shell scatter in 1991. In 1997 Pacific Legacy expanded the boundary and tested the site (Jackson et al. 1998:285). They found the site to be a low to moderately dense freshwater mussel shell scatter, faunal bone, and associated artifacts. Some of these artifacts include 12 chert flakes, an obsidian biface, sandstone manos and metates, seven olive snail shell beads and a clam shell disk bead. The shell beads found in 1997 suggest the site dates to the Upper Archaic (2500–850 cal B.P.) and the Emergent Periods (850 cal B.P.–historic). Two radiocarbon dates from freshwater mussel shell excavated in 1997, 925–660 B.P. and 645–480 B.P., support these temporal associations. As a result of these excavations Pacific Legacy recommended that CA-KER-5401 is not eligible for the NRHP or the CRHR because the site does not retain the potential to yield further information important to prehistory.

The site was revisited by URS in 2008 as part of the original HECA project (Farmer 2008:5-21). During this visit URS noted more surface artifacts than reported in 1997, and expanded the site boundary to the south and west. URS reports the presence of two possible house pits; an unspecified number of chert, obsidian, and quartzite flakes, 17 groundstone fragments, three steatite fragments, four lithic tools, and one olive snail shell bead. In addition, the shell density is reported to be moderate to dense, with the highest concentrations reaching 50 or more fragments or more per 10 square feet near the eastern portion of the site. Finally, the site was visited by Stantec in 2011 as part of the current project. They note that the artifact scatter extends to the north and west of the previously mapped boundaries of the site, and recommend further survey and testing prior to construction of the proposed project (Stantec 2011:8).

The more particular physical context for site CA-KER-5401, extrapolating information from **Cultural Resources Figure 1** to the location of the site, appears to be within the Elk Hills Quaternary alluvial fan deposits of the *Qa* unit. The possibility of buried cultural resources within the alluvial fan deposits is expected to be low-to-moderate. However, given the close proximity of the Buena Vista Slough, staff has determined that the potential for buried deposits at this site is moderate. This expectation is supported by the 1997 excavations which noted cultural materials approximately 1.6 feet below the modern ground surface (Jackson et al. 1998:285).

Previous researchers do not agree about the nature of CA-KER-5401. Pacific Legacy considers the site to be a small *Multi-constituent (Short Term Habitation)* site which is not eligible for the NRHP or CRHR. In contrast both URS and Stantec noted additional artifacts and features at the site which suggest that it is a *Midden (Long Term Habitation)* site that may be eligible for the NRHP and CRHR. Staff understands that OEHI has conducted additional fieldwork in the proposed EOR components and may have resolved this issue, per Data Requests A141–146 (CEC 2012b:8–13; URS 2012c). At the time of this writing, however, staff has not received this information. Therefore staff was unable, on the basis of the information provided, to determine if CA-KER-5401is eligible for the NRHP or CRHR. Staff will present OEHI’s latest methods and findings, and staff’s analysis, in the FSA/FEIS. For this analysis, however, staff assumes that CA-KER-5401 is a historical resource and historic property.

HECA-2008-6

HECA-2008-6 is a prehistoric archaeological deposit approximately 1.9 acres in area. The surface component of the site measures approximately 384 feet north–south and 220 feet east–west. It is located along the proposed CO_2 pipeline south of the West Side Canal and the California Aqueduct. The site area is a gently sloping alluvial piedmont with north aspect and open exposure. The setting provides an overview of the former network of sloughs running along the western margin of the Central Valley. The site was previously used for agriculture and livestock grazing and has been impacted by a large equipment track which cuts through the center of the site from north to south. Currently the site is covered with low grasses. The present site surface is composed of loosely compacted silty sand with limestone and sandstone inclusions. Further details about the site surface are unspecified. This site consists of a sparse scatter of lithic debris and freshwater mussel shell including nine pieces of Monterey chert and basalt representing early core and tool finishing reduction stages. One sandstone metate with a single bi-directional use face is also present. The site resembles numerous others of similar constituents and various sizes recorded on the north flank of the Elk Hills. Several other sites are recorded within a mile radius. Separations between sites are based on the presence and absence of cultural remains and topography. HECA-2008-6 was recorded in 2008 by URS as part of the original HECA project (Farmer 2008:5-7). However, OEHI did not mention it in their technical report (Stantec 2011).

The more particular physical context for site HECA-2008-6, extrapolating information from **Cultural Resources Figure 1** to the location of the site, appears to be within the Elk Hills Quaternary alluvial fan deposits of the *Qa* unit. The possibility of buried cultural resources within the alluvial fan deposits is expected to be low-to-moderate. However, given the close proximity of the Buena Vista Slough, staff has determined that the potential for buried deposits at this site is moderate. This expectation is supported by field observations which note shell midden in animal burrow back dirt, indicating a subsurface component to the site (Farmer 2008:5-7). The actual depth of the site has not been determined, however.

The 2008 site description suggests that the site was a limited use resource area used for processing seeds, plants, and fresh water mussels. However, a temporal association was not identified. Staff agrees with this functional characterization, and suggests that this site can be classified as a *Multi-constituent site.* In addition, the original recorders of the site recommend that it is not eligible for the NRHP and CRHR because of its lack of ability to yield information important to prehistory (Farmer 2008:5-7). However, staff notes that OEHI has not conducted the fieldwork required to gather data for formal site eligibility determinations. Without primary field data on the presence and nature of a subsurface component for the site, beyond the anecdotal observations provided, staff cannot evaluate the site sufficiently to determine if the site may retain the potential to yield information important to prehistory. Staff understands that OEHI has conducted additional fieldwork in the proposed EOR components and may have resolved this issue, per Data Requests A141–146 (CEC 2012b:8–13). At the time of this writing, however, staff has not received this information. Therefore staff was unable, on the basis of the information provided, to determine if HECA-2008-6 is eligible for the NRHP or CRHR. Staff will present OEHI's latest methods and findings, and staff's analysis, in the FSA/FEIS. For the purposes of this analysis, staff assumes that HECA-2008-6 is a historical resource and historic property.

HECA-2008-7

HECA-2008-7 is a prehistoric archaeological deposit approximately 7 acres in area. The surface component of the site measures approximately 899 feet north–south and 338 feet east–west. It is located along the proposed CO_2 pipeline south of the West Side Canal and the California Aqueduct. The site is located on a broad, north trending, terrace finger ridge that is bound on the east and west by deeply incised north trending drainages. The setting provides an overview of the former network of sloughs running along the western margin of the Central Valley. Formerly an agricultural field, the soil is now fallow and denuded of vegetation, although occasional Salt Bush and grasses are present. The present site surface is composed of loosely compacted silty sand with limestone and sandstone inclusions. This site consists of two house depressions, multiple dense concentrations of freshwater mussel shell fragments, Monterey and Franciscan chert debitage, and one groundstone fragment. The house depressions, Feature 1 to the west and Feature 2 to the east, are located in the southern portion of the site. They are being eroded by a small wash, flowing through the depressions to the east. Feature 2 contains a dense fresh water mussel shell midden. No further information about the features was provided. Artifacts present at the site include 10 pieces of chert debitage which represent early to late stage core reduction. Also present is a sandstone bowl fragment which has been ground through the bottom of the bowl. This is known as “killing” the bowl, a process tied to Yokut funerary practices. This artifact suggests that human burials may be present at the site. The shell concentrations range from moderate (2–3 fragments per 10 square feet) to very dense (20–30 fragments per 10 square fee). HECA-2008-7 was recorded in 2008 by URS as part of the original HECA project (Farmer 2008:5-8). However, OEHI did not mention it in their technical report (Stantec 2011).

The more particular physical context for site HECA-2008-7, extrapolating information from **Cultural Resources Figure 1** to the location of the site, appears to be within the Elk Hills Quaternary alluvial fan deposits of the *Qa* unit. The possibility of buried cultural resources within the alluvial fan deposits is expected to be low-to-moderate. However, given the close proximity of the Buena Vista Slough, staff has determined that the potential for buried deposits at this site is moderate. This expectation is supported by field observations which note shell midden in animal burrow back dirt and eroded areas, indicating a subsurface component to the site (Farmer 2008:5-8). The actual depth of the site has not been determined, however.

The 2008 site description suggests that the site was a habitation site dating to the “Middle Period” (Ruelas 2008). Staff agrees with this functional characterization, and suggests that this site can be classified as either a *Midden (Long Term Habitation)* or a *Multi-constituent (Short Term Habitation) site.* However, staff disagrees with the proposed temporal affiliation. “Killed” groundstone is characteristic of the Emergent Period (850 B.P.–historic). In addition, the original recorders of the site recommend that it is potentially eligible for the NRHP and CRHR because of its ability to yield information important to prehistory, and recommended evaluation phase excavation be conducted in order to explore the integrity of the resource (Farmer 2008:Table 5-1). Staff understands that OEHI has conducted additional fieldwork in the proposed EOR components and may have resolved this issue, per Data Requests A141–146 (CEC 2012b:8–13). At the time of this writing, however, staff has not received this information. Therefore staff was unable, on the basis of the information provided, to determine if HECA-2008-7 is eligible for the NRHP or CRHR. Staff will present OEHI's latest methods and findings, and staff's analysis, in the FSA/FEIS. For this analysis, however, staff assumes that HECA-2008-7 is a historical resource and historic property.

HECA-2008-11

HECA-2008-11 is a prehistoric archaeological deposit approximately 1.7 acres in area. The surface component of the site measures approximately 243 feet north–south and 312 feet east–west. It is located along the proposed CO_2 pipeline south of the West Side Canal and the California Aqueduct. The site is located on a low terrace which gently slopes to the northeast. It is bounded by seasonal drainages on the east and west sides. The eastern drainage has been used for modern trash disposal. The setting provides an overview of the former network of sloughs running along the western margin of the Central Valley. Formerly an agricultural field, the soil is now fallow and denuded of vegetation, although occasional salt bush, sagebrush and low grasses are present. The site surface is composed of loosely compacted silty sand with limestone inclusions. Site disturbances include a dirt road which cuts through the center of the site from north to south, and an ephemeral drainage also cutting through the center of the site from southwest to northeast. This site consists of a light scatter of freshwater mussel shells (1 fragment per 10 square feet), two flakes of Monterey chert, a groundstone fragment, and a large Pismo clam shell bead. This shell bead is a traditional funerary object of the Southern Valley Yokuts. This artifact suggests that human burials may be present at the site. HECA-2008-11 was recorded in 2008 by URS as part of the original HECA project (Farmer 2008:5-9). However, OEHI did not mention it in their technical report (Stantec 2011).

The more particular physical context for site HECA-2008-11, extrapolating information from **Cultural Resources Figure 1** to the location of the site, appears to be within the Elk Hills Quaternary alluvial fan deposits of the *Qa* unit. The possibility of buried cultural resources within the alluvial fan deposits is expected to be low-to-moderate. However, given the close proximity of the Buena Vista Slough, staff has determined that the potential for buried deposits at this site is moderate. The actual depth of the site has not been determined, however.

The 2008 site description suggests that the site was a limited use resource area used for processing seeds, plants, and fresh water mussels. Staff agrees with this functional characterization, and suggests that this site can be classified as a *Multi-constituent site.* However, a temporal association was not identified. Staff notes that clam disk beads are associated with both the Middle Archaic (7450–2500 cal B.P.) and the Emergent Period (cal 850 B.P.–historic) (Gibson 1992). In addition, the original recorders of the site recommend that it is potentially eligible for the NRHP and CRHR because of its ability to yield information important to prehistory, and recommended evaluation phase excavation be conducted in order to explore the integrity of the resource (Farmer 2008:Table 5-1). Staff understands that OEHI has conducted additional fieldwork in the proposed EOR components and may have resolved this issue, per Data Requests A141–146 (CEC 2012b:8–13). At the time of this writing, however, staff has not received this information. Therefore staff was unable, on the basis of the information provided, to determine if HECA-2008-11 is eligible for the NRHP or CRHR. Staff will present OEHI's latest methods and findings, and staff's analysis, in the FSA/FEIS. For the present analysis, staff assumes that HECA-2008-11 is a historical resource and historic property.

HECA-2008-12

HECA-2008-12 is a prehistoric archaeological deposit approximately 4 ac in area. The surface component of the site measures approximately 262 ft north–south and 656 ft east–west. It is located along the proposed CO_2 pipeline south of the West Side Canal and the California Aqueduct. The site is located on a low terrace which gently slopes to the north. It is bounded by a seasonal drainage which wraps around the southern and eastern perimeter. The setting provides an overview of the former network of sloughs running along the western margin of the Central Valley. Formerly an agricultural field, the soil is now fallow and denuded of vegetation, although occasional low grasses are present. This site consists of a light scatter of freshwater mussel shells, one quartzite core tool, two sandstone groundstone fragments, and two steatite bowl fragments. HECA-2008-12 was originally recorded in 2008 by URS as part of the original HECA project (Farmer 2008: 5-10). Stantec did not mention HECA-2008-12 in their initial technical report (Stantec 2011).

The more particular physical context for site HECA-2008-12, extrapolating information from **Cultural Resources Figure 1** to the location of the site, appears to be within the Elk Hills Quaternary alluvial fan deposits of the *Qa* unit. The possibility of buried cultural resources within the alluvial fan deposits is expected to be low-to-moderate. However, given the close proximity of the Buena Vista Slough, staff has determined that the potential for buried deposits at this site is moderate. The actual depth of the site has not been determined, however.

The 2008 site description suggests that the site was a habitation site (Farmer 2008:5-10). Staff agrees with this functional characterization, and suggests that this site can be classified as either a *Midden (Long Term Habitation)* or a *Multi-constituent (Short Term Habitation) site.* In addition, the original recorders of the site recommend that it is potentially eligible for the NRHP and CRHR because of its ability to yield information important to prehistory, and recommended evaluation phase excavation be conducted in order to explore the integrity of the resource (Farmer 2008:Table 5-1). Staff understands that OEHI has conducted additional fieldwork in the proposed EOR components and may have resolved this issue, per Data Requests A141–146 (CEC 2012b:8–13). At the time of this writing, however, staff has not received this information. Therefore staff was unable, on the basis of the information provided, to determine if HECA-2008-12 is eligible for the NRHP or CRHR. Staff will present OEHI's latest methods and findings, and staff's analysis, in the FSA/FEIS. For the present analysis, staff assumes that HECA-2008-12 is a historical resource and historic property.

Multi-component Archaeological Resources

CA-KER-89/H (P-15-89)

CA-KER-89/H is a multi-component archaeological deposit approximately 0.2 acre in area. The surface component measures approximately 148 feet north–south and 49 feet east–west. It is located along the proposed HECA process water line, primarily on the southwest side of the West Side Canal. However, the presence of an isolated chert flake (KRM-IF-006) on the northeast side of the canal suggests that the prehistoric component may extend to the east. Vegetation present at the site consists of salt bush and low grasses, growing in sandy alluvium. The site was originally recorded in 1950 as an "Indian Burial Mound." A relative site location is plotted within the Lokern 7.5-minute USGS quadrangle, however no other information about the site was provided. When the site was revisited in 1990 it was recorded as a multi-component site. The prehistoric component consists of a midden mound three to four meters high. Cultural materials at the site include a scatter of lithic debitage, turtle and rabbit bones, various human bones, and an olive snail split-punched bead. The historic component consists of purple glass and other historic artifacts. Additional information about this component is unspecified.

The more particular physical context for site CA-KER-89/H, extrapolating information from **Cultural Resources Figure 1** to the location of the site, appears to be within the Buena Vista Slough deposits of the *Qb* unit. As the presence of this site demonstrates, the possibility of buried cultural resources within the slough deposits is expected to be high.

Previous researchers suggest no temporal association or functional interpretation for the site. However, staff suggests that the midden, faunal remains, human remains, and shell beads indicate that this site can be classified as a *Midden (Long Term Habitation)* site. In addition, staff notes that olive snail split-punched beads date to the Middle (7500–2500 cal B.P.) and Upper Archaic periods (cal 2500–850 B.P.) (Gibson 1992). The applicant has not conducted the fieldwork required to determine if an intact buried component of CA-KER-89/H extends to the east side of the West Side Canal. Without primary field data on the presence of a subsurface component for the site, staff cannot evaluate the site sufficiently to determine if the site may retain the potential to yield information important to prehistory. Staff requested this primary field data in Data Requests A192–194 (CEC 2012a:7–9). The applicant responded that it intended to avoid damaging archaeological resources along the proposed process water line, including CA-KER-89/H (URS 2013b:A192-2). In addition, the applicant stated elsewhere that test excavation was not warranted at CA-KER-89/H or KRM-ISO-006 because the former is not located in the PAA/APE and the latter is simply an isolated find (URS 2013c:147-1). Staff believes that the applicant is taking an overly particularistic view of archaeological resource boundaries in the vicinity of CA-KER-89/H. Staff agrees that CA-KER-89/H, as currently mapped, is located west of the PAA/APE. Staff also agrees that KRM-IF-006 may be an isolated find. However, the proximity of these two resources, both of which have not witnessed test excavation and are separated by a water conveyance that was built after the archaeological resources were formed, begs the question whether the two resources constitute a single site that has been bisected by the West Side Canal. On the basis of the information provided to date, staff is unable to determine if CA-KER-89/H extends into the PAA/APE and, if so, whether it is eligible for listing in the CRHR or NRHP. For the present analysis, staff assumes that CA-KER-89/H is a historical resource and historic property.

CA-KER-5356/H (P-15-6725)

CA-KER-5356/H is a multi-component archaeological deposit approximately 0.02 acre in area. The surface component measures approximately 361 feet north–south and 318 feet east–west. It is located along the proposed HECA process water line, primarily on the southwest side of the West Side Canal. However, the presence of an isolated chert flake (P-15-7176) on the northeast side of the canal suggests that the prehistoric component may extend to the east. Artifacts are visible in a graded dirt road and in an agricultural field to the north. The site may extend to the south as well, but dense Tamarisk thickets prevented exploration in this direction. Soil at the site is dark grey to whitish sand. Modern disturbances include construction of the West Side Canal, road construction and agricultural activities. The prehistoric component consists of four pieces of white Temblor chert debitage. The historic component consists primarily of glass and ceramic fragments. The glass includes clear, sun colored amethyst, amber, green and white fragments. Also present are blue ceramic fragments which may be "Fiesta Ware", as well as multiple fragments of glazed earthenware in light blue, and red with brown. (Scott 2000; Wear and Frazier 1998:1–2).

The more particular physical context for site CA-KER-5356/H, extrapolating information from **Cultural Resources Figure 1** to the location of the site, appears to be within the Buena Vista Slough deposits of the *Qb* unit. As the presence of this site demonstrates, the possibility of buried cultural resources within the slough deposits is expected to be high.

Previous researchers suggest no temporal association or functional interpretation for either site component. In addition, no eligibility recommendation was made. However, subsurface excavation was conducted as part of the La Paloma Generating Project in 1999. One 33-feet-long trench paralleling the levee road was excavated approximately 66 ft north of the artifacts observed in the road. No buried component was identified in this trench (URS Greiner Woodward Clyde 1999:L-9). Nonetheless, subsurface archaeological deposits may exist on the east side of the West Side Canal. Without primary field data on the presence of a subsurface component for the site on the east side of the canal, staff cannot evaluate the site sufficiently to determine if the site may retain the potential to yield information important to prehistory. Staff requested this primary field data in Data Requests A192–194 (CEC 2012a:7–9) or evidence from the applicant that P-15-7176 would not be affected by the proposed project (Data Request 147; CEC 2012b:13–14). The applicant responded that CA-KER-5356/H is not in the PAA/APE and that P-15-7176 is an isolate that does not require further treatment. Therefore, the applicant reasons that neither avoidance measures nor an archaeological test excavation at P-15-7176 is warranted (URS 2013b:A192-2, 2013c:147-1). Staff disagrees with the applicant's conclusion, as the applicant has not determined whether subsurface deposits are present at P-15-7176, which appears to be an eastern extension of CA-KER-5356/H. Staff requests that the applicant either conduct a test excavation to determine whether significant subsurface deposits are present at P-15-7176 or propose measures that would prevent subsurface disturbance during construction in this area. In the interim, staff assumes that P-15-7176 is a historical resource for the purposes of CEQA and a historic property under Section 106 of the NHPA.

Ethnographic Resources

No CRHR-eligible ethnographic resources have been found in the PAA/APE.

Historic Archaeological Resources

To date, one historic archaeological resource has been identified in the HECA portion of the PAA/APE: HECA-2010-2.

HECA-2010-2

Historic archaeological site HECA-2010-2 was first recorded on July 29, 2010. A subsequent visit and DPR 523 form update was made on February 29, 2012. (Hale et al. 2012:41–42, Appendix C; URS 2012a:5.3-29, 5.3-30).

HECA-2010-2 consists of the remnants of a demolished farmhouse. The site covers an area approximately 220 feet north–south and 135 feet east–west. It contains a single feature, nonnative trees, and a scatter of historic artifacts. Feature 1 comprises a partial, concrete house foundation. A cinderblock addition to the house is evident along the north side of the foundation. Also evident in Feature 1 are the remains of clay, cast-iron, and polyvinylchloride (PVC) sanitary (septic) and water pipes. (Hale et al. 2012:41; URS 2012a:5.3-29).

Artifacts present at HECA-2010-2 consist of structural debris (concrete rubble) and approximately 35 specimens of complete and fragmentary metal cans, bottle glass, and ferrous metal fragments. Time-sensitive artifacts included an aqua-colored glass bottle top and two hole-in-top, match-filled, crimped-seamed evaporated milk cans. The two evaporated milk cans are types manufactured between 1917 and 1929 (URS 2012e:A68-3.) Most aqua-colored bottle glass predates 1910 (University of Utah et al. 1992).

The applicant surmises that the historic residence was likely built between the 1920s and 1930s, based on a "review of archival sources, including aerial photographs and topographic maps" (Hale et al. 2012:41; URS 2012a:5.3-29). Staff concurs that this is a reasonable inference, although the archival records examined by the applicant's cultural resource consultants provide a sufficient basis to narrow the construction date down further.

Historic-period occupation of the property on which HECA-2010-2 is located was unlikely prior to the 1890s–1919 because historic maps and documents indicate that the site location was in swamp and overflowed land. Additionally, it was not until 1919 that all of the lands between the West and East Side canals were reclaimed and farmed by Miller & Lux. (GLO 1856d, 1868d; URS 2012a:5.3-14.) Furthermore, no buildings or structures are evident at the location of HECA-2010-2 on historic maps dating between 1853 and 1918 (Aubury 1904; Buffington 1912; Congdon 1898; GLO 1856d, 1868d; Hall 1885; Punnett Bros. 1914; Stegman 1918; von Leicht and Kaufman 1875). A historic topographic map, however, depicts a building at the location of HECA-2010-2 in 1927 or 1929 (USGS 1932a). Therefore, the former residence at HECA-2010-2 would have been built between 1919 and 1929. Dateable historic artifacts found at the archaeological site, albeit few in number, generally support a construction interval of 1919–1929.

The historic record reveals that the land on which HECA-2010-2 is located was part of Miller & Lux's Buttonwillow Ranch from the 1870s till 1927, when Miller & Lux began to subdivide and sell the 52,000-acre ranch. About this time, Chatsworth, California farmers George W. and Dedo S. Olsen purchased the property, although they did not move to the Buttonwillow area with their sons until 1935. Son Leland K. and his wife Ruth B. lived at HECA-2010-2 from 1936 to the 1990s. (URS 2012a:5.3-29; Webb and Miller 2012:2.) The occupation of HECA-2010-2 can therefore be defined as spanning the interval of 1919–1927 to the 1990s.

The condition of HECA-2010-2 is poor. Between 2010 and 2012, the landowner or the landowner's agent graded the parcel on which HECA-2010-2 is located, removing all evidence of the former residence, artifact scatter and structural debris alike. (URS 2012a:5.3-30.) The property now contains a newly planted orchard.

On the basis of its apparent destruction, the applicant does not evaluate HECA-2010-2 for NRHP eligibility or for historical significance under CEQA. Discounting the potential for subsurface archaeological deposits in the form of privy pits (outhouses) or refuse pits, the applicant states that since structural remnants and artifacts are no longer evident at the archaeological site, construction of the proposed project would not damage HECA-2010-2 (URS 2012a:5.3-30, 5.3-39). Staff disagrees with this assessment.

The applicant downplays the probability of a privy having been used at HECA-2010-2 because the foundation remnant included clay, cast-iron, and PVC pipes, suggestive of indoor plumbing that debouched into a septic system (URS 2012a:5.3-30). Given that the residence was occupied from as early as 1919–1927 through the 1990s, an addition was made to the house at an unknown time, and more than one septic/water technology is evident in the pipes observed in 2010 (URS 2012a:5.3-29), there is ample potential for the occupants of HECA-2010-2 to have shifted from privy waste disposal to septic waste disposal. The latter is the prevailing household waste disposal method used in the project vicinity today (URS 2012a:5.14-24). For rural residential properties occupied through the 1930s, it was commonplace for waste disposal to depend on an outhouse or privy:

> *Although there was a rising awareness of proper sewerage techniques in small towns across California, these small communities rarely had the capital necessary to make the costly improvements in their sewage or water supply systems without raising taxes or securing bonds for such improvements. Instead, a number of the more rural communities relied upon well water and vault privies through the Great Depression of the 1930s. (Caltrans 2010:64, emphasis added).*

Privies would likely be located north and east of the house so that the prevailing westerly and northwesterly winds would blow unwanted odors away from the residence. Therefore, the proposed natural gas pipeline has the potential to intersect any privy pits that might be present. Privy pits frequently contain archaeological materials that qualify archaeological resources for listing in the NRHP or CRHR. It is therefore critical to a cultural resources impact assessment to determine whether a privy pit is present at HECA-2010-2. Accordingly, staff has issued data requests to the applicant to prepare a work plan for determining—through metal detection, probing, or other methods—whether a privy is present in the PAA/APE in the vicinity of HECA-2010-2 and implement the work plan. If a privy is located as a result of the field investigation, the resource would have to be evaluated for NRHP eligibility and historical significance under CEQA or avoided through project design. The applicant is working on this request. (CEC 2012c:17–20; URS 2012b, 2012f.) An assessment of HECA-2010-2's historical significance and potential project impacts on it cannot be conducted until the applicant completes and implements the work plan described previously in this paragraph. For the present analysis, staff assumes that HECA-2010-2 is a historical resource and historic property.

The archaeological site is associated with a Quonset hut, which was recorded separately as Map Reference No. 5 (Olsen Property) in February 2012 (JRP 2012:23, 29–30, Table 1, Appendix B). Staff evaluates the historical significance of Map Reference No. 5 in the "Built-Environment Resources" subsection below.

Built-Environment Resources

The Amended AFC included 15 identified and recorded historic built environment resources (some are multiple resources) within the PAA/APE. These consist of a variety of resources, including rail lines, water conveyance systems and structures, transmission lines, agricultural complexes, residential properties, water storage facilities and a wildlife reserve. Resources within the proposed project footprint and controlled area are residential and agricultural complexes. **Cultural Resources Table 9** summarizes the identified resources and their eligibility for listing on the NRHP/CRHR as determined by the applicant's historical consultant and recorded on DPR 523 forms, submitted with the application. **Cultural Resources Table 9** also includes eight historic built environment resources within the PAA/APE which were not included in the current application.

The Amended AFC included some resources that were recorded in 2009 and based upon the 2009 project PAA. The PAA/APE for the current project has changed for the linear routes. Data Requests A181, 182,184,185 and 191, issued by staff on November 2, 2012 (CEC 2012a), requested new or updated DPR 523 Forms and evaluations of these resources based on the current PAA/APE. Responses have been received for most of these data requests; others are pending under the applicant's request for additional time. The applicant objected to several staff data requests, including A181(b), A186 (a–c) and A187(a–c). Responses to data requests will be integrated and analyzed with the appropriate resources.

Most of the Buena Vista Water Storage District (BVWSD) resources are evaluated on one DPR 523 form and listed as Map Reference 14 (MR 14). The exceptions are the structure known as Old Headquarters Weir (MR 10) and KRM-001H, which are evaluated separately. Other than the California Aqueduct (MR 11), the Old Headquarters Weir was the only other historic built environment resource within the PAA/APE found by the applicant to be eligible for listing on the NRHP/CRHR.

Map Reference No. 1 (MR 1) Agricultural Buildings

The collection of agricultural buildings known as MR 1 is located in the PAA/APE for the proposed railroad spur. The buildings are located north of SR 58 and east of Tracy Road. The DPR 523 form includes a photograph of the property taken facing the northwest. Transmission lines and towers are visible in the background of the photograph. Staff has not visited this resource and bases the analysis upon information provided by the applicant and images from Google Earth 2012. Google Earth historic aerial images dating back to 1994 indicate the same basic arrangement of buildings and site features as they exist today. The applicant's evaluation finds there are six dilapidated buildings that were moved to this location after 1973 and that previously the property was undeveloped. Buildings are described as wood-frame construction with sidings of stucco, vertical wood or corrugated metal. Roof forms are described as having either shed or gable forms of shingles or metal.

A building not shown or discussed on the DPR form appears to be a grain storage type building. As seen from Google Earth's 2011 imagery, it is a circular building with a roof that may be opened. It is not clear that this structure is seen in the 1994 aerial imagery but it is seen in the Google Earth 2004 image. There appears to be a structure in that location in the 1994 image, but the resolution of the image is so poor as to be indeterminate.

Google Earth imagery from 2009 actually provides the clearest view of the property. In addition to the afore-mentioned structures, there is evidence of a fenced livestock pen and another grain storage structure. A dinghy or small rowboat is visible on the ground near the livestock pen. The quality of the 2011 aerial makes it difficult to determine if the livestock pen is still extant.

The applicant concluded that the property is not eligible for listing on the NRHP/CRHR for any of the criterion and, based upon available analysis and evidence, staff concurs with this conclusion. Staff will make a site visit prior to publication of the FSA/FEIS to confirm this conclusion and will provide an expanded evaluation.

Map Reference No. 2 Southern Pacific McKittrick (Asphalto) Branch Railroad Line

Energy Commission staff Data Request A181, issued by staff on 11/2/2012 (CEC 2012a), requested an updated DPR 523 Form and evaluation of this resource based on the current project PAA/APE. DR A181a requested the updated evaluation and 181b requested a discussion of how the proposed railroad laydown yard would impact either the existing rail line or the historic spur. The applicant objected to providing additional information on the railroad construction laydown area on the grounds that the resource was not found to be eligible for listing on the CRHR or NRHP, and therefore not a historical resource under CEQA. The applicant concluded that no discussion regarding potential impacts on this property is necessary in determining the significance of environmental effects to cultural resources under CEQA. While staff tentatively concurs that this resource is not eligible, staff notes that until the DPR 523 Form was updated to evaluate the portion of the rail road within the current PAA/APE, that determination was premature.

MR 2 (CA-KER-2050-H/JRP-HECA-26) is a segment of the McKittrick Branch of the Southern Pacific Railroad extending between I-5 and Buttonwillow and originally constructed in 1893. The line originally connected Bakersfield to Asphalto and McKittrick to the west. By 1905, the branch line was delivering both materials and people to the oil fields of McKittrick and returning with oil to be shipped to market. Originally intended to run all the way to Sunset and to the asphalt and oil production fields of Solomon Jewett and Hugh Blogget, the branch line was formed in an agreement between these men and the Southern Pacific Railroad, creating the Standard Asphalt Company. The partnership was dissolved in 1893 amidst the Great Panic. Later partnerships formed the Sunset Railway. The McKittrick Branch was retained by Southern Pacific and extended to Olig in 1901 (Brewer 2001). The Southern Pacific Railroad removed the line from Buttonwillow to western points in 1960 (URS 2012a). None of the original stations, such as the Buttonwillow Station, are extant from Buttonwillow to the west.

A 1.3-mile segment is located within the PAA/APE for the proposed HECA transmission line. The portion of the Southern Pacific McKittrick track along the southern edge of SR 58 is described in the updated DPR 523 form (December, 2012) for MR 2 as light weight rails with rock ballast and wood ties. The tracks are raised above grade along much of SR 58 frontage. The rails are connected with bolted plates. For most of its length, the line is a single track. Sidings are located in Buttonwillow crossing Mirasol Avenue in central Buttonwillow and at the J.G. Boswell cannery. Three spurs serve the Murray Cotton Gin, an industrial complex south of Meadow Street in Buttonwillow, Farmer’s Cooperative Gin buildings east of Wasco Way, and the J.G. Boswell cannery. Spurs are located near a large storage facility near Old Tracy Road, not far from I-5. While the line was constructed in 1893, it was shortened in 1982 and had tie replacement and reballasting in 1990–1991. Staff observed a Carnegie 1899 imprint stamped on the spur line near the Farmer’s Cooperative Gin, east of Wasco Way (not located in the current PAA/APE). The line is in use and operated by the San Joaquin Valley Railroad, a railroad in the short-line business group of Union Pacific railroad and carries agricultural products and other freight[31].

The segment of the railroad line that falls within the PAA/APE is located in the vicinity of the intersection of SR 58 and Tracy Lane. Staff has not conducted a survey of this intersection but has driven the SR 58 roadbed adjacent to the railroad and stopped at other locations nearby. Staff does not believe that conclusions would change based upon first hand observation but does expect to make a site visit before publication of the FSA/FEIS.

Staff agrees with the eligibility evaluation provided in the Amended AFC and concludes that MR 2 is not eligible for inclusion in the CRHR or NRHP. As summarized in the DPR 523 form provided in the Amended AFC, the Southern Pacific McKittrick Branch, previously the Southern Pacific Asphalto Branch, does not appear to meet the criteria for listing in the CRHR or NRHP because it does not have historical significance or integrity. The branch line does not have significant associations with the development of petroleum production in the fields surrounding McKittrick; therefore, it is not eligible under Criterion 1/A. Additionally, its integrity is impaired by the removal of the section

[31] http://www.uprr.com/customers/shortline/lines/sjvr.shtml

extending west from Buttonwillow to the asphalt/oil production areas. While Southern Pacific constructed the branch in cooperation with Solomon Jewett and Hugh Blogget, early oil and asphalt producers in the area, oil production had begun before the railroad agreement. The branch line is not associated with a significant individual; therefore, it is not eligible under Criterion 2/B. When considered under Criterion 3/C, staff finds that the railroad branch does not embody distinctive architectural characteristics of a period, type, or method of construction as little of the original materials exist and the replacement materials do not have significance. This resource is also not eligible under Criterion 4 because it is not likely to yield information important to history. In rare instances, structures can serve as sources of important information about historic construction materials or technologies Criterion 4/D; however, the railroad segment does not appear to be a principal source of important information in this regard. In addition to a lack of historic significance, the resource lacks historic integrity to 1893, its original date of construction and possible period of significance.

Map Reference No. 3 Pacific Gas & Electric (PG&E), Southern California Edison (SCE) Transmission Lines and Towers

The information submitted on the DPR 523 Form (updated December 2012) documents two sets of transmission lines and towers. Lines A & B were constructed by SCE and PG&E, respectively. The applicant dates the construction to between 1943 and 1956. Lines A & B originate at the Midway Substation at the eastern edge of Buttonwillow, cross SR 58 in a southeasterly direction and then turn easterly, paralleling, about three-quarters of a mile away, SR 58 to Bakersfield. Lines C & D, also built by SCE and PG&E respectively, were built between 1956 and 1973. These lines also originate at the Midway Substation, cross SR 58 in a southeasterly direction and continue in a southeasterly route roughly paralleling the East Side Canal.

Lines A & B are steel lattice towers, according to the DPR 523 form, carrying single or double circuits. Lines A & B appear to consist mostly of four-legged, three-armed steel lattice towers. Lines C & D are composed of similar three-armed towers and towers with a strong horizontal within an upright V-shape. Each of these designs is reflective of the power companies that constructed them.

The applicant's evaluation concludes that none of the transmission lines or their related structures is eligible for listing on the NRHP/CRHR. Staff concurs with this conclusion. None of the lines and towers appears to be significant for their association with development of electrical transmission in Kern County and are constructed well after the period of electrical development in California. Therefore, they are not eligible for listing on the CRHR or NRHP under Criterion 1/A. Under CRHR/NRHP Criterion 2/B, these lines do not appear to be eligible as they are not associated with any significant people in history. They do not possess distinctive characteristics of construction or high artistic value and are therefore ineligible under Criterion 3/C. These towers are not a source of important information regarding human history and are therefore ineligible under Criterion 4/D.

Map Reference 4 6010 Buerkle Road Residence

This residential property is located on Buerkle Road approximately 700 feet west of the East Side Canal. While it falls within the historic built environment period, the building has been remodeled and does not convey any sense of recognized style dating either to the period of construction or any later discernible style. The date of construction provided on the DPR 523 Form is 1964, with remodeling and pool construction taking place in 1997, 2007 and 2008. Landscape improvements also appear to be fairly recent. The resource does not appear to be eligible for listing on the NRHP/CRHR.

MR 4 is a residential property built in 1964 and located at 6010 Buerkle Road within the PAA/APE for the proposed HECA rail road line. The property was originally part of the Miller and Lux holdings. Martin L. Snow purchased the property in the 1950s. Martin L. Snow was one of the pioneers in developing cotton in the Buttonwillow area. He was joined by his son, Martin, in an agricultural enterprise and the two owned and developed many parcels, of which this property was one. By 1963, D. Snow owned the property and was likely the builder of the residence. Ownership changed again several times after 1973. Since its original construction in 1964, the residence has undergone significant modifications resulting in an indiscernible architectural style. The house has undergone renovations including the addition of a swimming pool and replacement windows. The stucco and roof also appear to have been updated during one of the recent modernizations of the residence. It is difficult to determine the original architecture style of the house due to the extensive remodeling and the addition or extension of a front gable porch with classically-inspired columns. These renovations have severely affected the integrity of the original structure.

Staff concurs with the conclusion reached by the applicant that site MR 4 is not eligible for inclusion in the CRHR or NRHP. The applicant provides the following significance evaluation in a confidential appendix to the Amended AFC (JRP 2012:Appendix B).

> *The property…is associated with the post-World War II, continued agricultural growth of Buttonwillow; however, this property was constructed well after other similar farmsteads, and does not represent a significant example of post-World War II building trends. By the time the residence was built, numerous farmsteads were developed throughout the eastern countryside of Buttonwillow. The multiple additions and remodeling of the building in addition to the separation of this parcel from its original larger agricultural parcel further contribute to the property's loss of integrity in association to the agricultural history of Buttonwillow. The residence does not appear to have important associations with historically significant events (NRHP Criterion A/CRHR Criterion 1). Furthermore, available evidence does not suggest that individuals associated with this property, have made significant contributions to our history. While the Snow family was a prominent landowner in the Buttonwillow area, their contribution alone is not significant to local, state, or national history (NRHP Criterion B/CRHR Criterion 2).*
>
> *Under Criterion C (Criterion 3), the parcel is a typical example of farmstead residential development when it was originally constructed on part of a larger agricultural parcel. Since the residence can no longer be classified under a specific architectural style due to significant modifications…it does not embody distinctive architectural characteristics of a period, type, or method of construction, and it is not the work of a master. In rare instances, buildings themselves can serve as sources of important information about historic construction materials or technologies (NRHP Criterion D/CRHR Criterion 4). The construction methods for the residence at 6010*

Buerkle Road are otherwise documented in a wide body of historical documents and literature; the building, therefore, does not appear to be a principal source of important information in this regard.

Map Reference 5 Quonset Hut 35034 Stockdale Highway

The property containing the Quonset Hut has been altered significantly in the last few years. The property, known as the Olsen Farm, at one time contained a collection of farm buildings, a residence and landscape trees. Everything except the Quonset Hut had been removed from the property prior to filing of the Amended AFC (URS 2012a). The site has since been planted with pistachio saplings in an orchard[32] (**Cultural Resources Figure 6**). The residence, which appears in Google Earth Aerial Imagery dated April 29, 2008, was removed prior to July 29, 2010. URS recorded that only structural remains and refuse existed by July 29, 2010 (Laurie and Kile 2010:1).

The 81-acre Olsen Farm was purchased by George Olsen in 1935 and the land was transferred to his sons. Leland Olsen and his wife, Ruth B., took up residence on the property in 1936. According to the DPR 523 Form for MR 5, the Olsens lived there until Leland died in 1993, followed by Ruth's death in 2002. Historic aerial imagery depicts a typical farmstead arrangement of buildings, with a residence surrounded by trees nearest the road and outbuildings primarily along the west side of the cleared area around the residence.

The DPR 523 form describes the farm purchased by George Olsen as likely a subdivided portion of the Buttonwillow Ranch owned by Miller & Lux. However, the resource does not retain the association with the historic land ownership of Miller & Lux, and now that the residence and outbuildings have been razed and the farm replanted as an orchard, the association with the Olsen Farm is also lost. While the Quonset Hut itself is an apparently intact representative of the circa 1940s portable military building type, it no longer has any contextual association with either the Olsen Farm or the military uses for the building. Staff agrees that the Quonset Hut has lost integrity of feeling, association, and setting even while maintaining its integrity of design, workmanship, materials and location. Staff therefore concludes that the resource MR 5 is not eligible for listing on the NRHP/CRHR.

Map Reference 6 Works Project Administration (WPA)-Era Culvert Headwalls along Dairy Road

MR 6 consists of four individual structures located along Dairy Road at the intersection of or north of Adohr Road. The DPR 523 forms identify the four structures as Points 1–4, with Point 1 being the northernmost feature. Point 1 consists of culvert headwalls on both sides of Dairy Road and a culvert, presumably under the roadbed. The Main Drain connects to an unnamed lateral drain where Point 1 is located, as seen in photographs on DPR 523 MR 6 and described in the resource description. As of September 2012, Point 1 no longer appears to be in use as there is fill dirt on either side of the road and

[32] Staff site visit September 18–20, 2012.

the culvert is not visible[33]. Both headwalls are stamped with WPA 1940 engravings (**Cultural Resources Figure 6**).

Point 2 is located mid-way between Point 1 to the North and Adohr Road to the south. Point 2 is a headwall on the east side of Dairy Road and is broken into three pieces. It is also stamped WPA 1940. Like Point 1 headwalls, this no longer appears to be usable or provide any drainage. There is fill next to the structure and no visible culvert. Like Point 1, existing conditions as of September 2012, are different from those recorded for the DPR 523 in February 2012. (JRP 2012:Appendix B).

Point 3 is located at the intersection of Dairy and Adohr roads and has headwalls on either side of Dairy Road. The eastern headwall and drainage channel includes a valve of some kind but it is not apparent that it is operable or in use. It is a valve structure usually seen in conjunction with a gate, to allow water to flow or to prevent it from flowing. On the east side, the top of a culvert is just visible and appears to lead to or from the west side. The west side headwalls of Point 3 appear to house culverts that lead to both the east side of Dairy Road and to the south side of Adohr Road. Point 4 consists of two headwall structures on the south side of Adohr Road. Point 3 would appear to connect to the easternmost headwall and culvert. As reflected in the DPR 523 form description, the eastern Point 4 headwall and culvert would connect to a drain leading to the West Side Canal. From Google Earth aerial imagery, it can be seen that this connector drain runs along the western boundary of the Adohr/Palm Farms, turns east at the southern boundary of the farms' residential area and then once again turns in a southerly direction through agricultural fields and presumably connects to the West Side Canal as stated in the DPR 523 forms. The western headwall and culvert at Point 4 may no longer be in use. (JRP 2012:Appendix B.) This may be confirmed by staff in a future site visit to the PAA/APE.

It would seem that in spite of the WPA-era construction and documentation as such on several of these headwall structures, there does not appear to be any known connection to a significant WPA construction project in this area. The DPR 523 forms state that WPA projects were underway generally in the Buttonwillow region and that the Chamber of Commerce made road building a priority. The integrity of several of the structures is badly compromised and some are no longer in use. The connection to the broader WPA-era construction activities and its important contribution to American history is limited by the very pedestrian nature of the structures, their design, placement along secondary drains and the localized activity they represent. Therefore, it is unlikely they are eligible for listing on the NRHP/CRHR under Criterion A/1. (JRP 2012:Appendix B.) Staff concurs with the evaluator's conclusion that the structures are not eligible under any of the criteria for listing on the NRHP/CRHR.

Adohr Farms/Palm Farms

In 1916, Merritt Huntley Adamson Sr. and his heiress wife, Rhoda Rindge Adamson, whose parents were the last owners of a vast Spanish land grant in Malibu, founded a state-of-the-art dairy in Tarzana called Adohr Farms; Adohr was Rhoda spelled backward. Dozens of dairies sprang up in Southern California in the early years of the

[33] Staff site visit September 18–20, 2012.

twentieth century as the population grew. Swan, Supreme, Excelsior, Crown City, Carnation, Driftwood and Alta Dena, to name a few, offered Southern California customers home-delivery of dairy products. Eventually, Adohr Farms had hundreds of delivery routes and customers in the new suburbs depended upon Adohr Farms for special deliveries (Rasmussen 1998).

A decade after establishing their dairy farm, when Adohr's famous reddish-golden brown Guernseys were known worldwide for their quality, size and productive capacity, the family opened a subsidiary, Adohr Creamery Company, on a 20-acre parcel in what was then the country. The new plant processed and distributed the dairy products produced on the Tarzana farm. For more than 40 years, the company's landmark, a life size statue of a little girl stopping a milkmaid who is posed by her grazing cow stood at La Cienega Boulevard and Sawyer Street. The statue is attributed to Herman Schultheis, circa 1937. (Rasmussen 1998; Ryerson 2012.) Around the pedestal of the statue is written "The largest Guernsey herd in the world" and "Guernsey Certified Milk." The statue is in storage at a processing plant in Tulare County, as the Adohr operations all ended by 1948 in the San Fernando Valley and what remained moved to Camarillo. The Camarillo farm was sold for the Westview Park subdivision in 1969.

In 1930, the Adamsons purchased 1,500 acres from Miller & Lux in the area northwest of Tupman near Buttonwillow. At that time, they built what is described as a farm headquarters building, dining hall and dormitory and completed other property improvements including wells. Three warehouse buildings were added between 1937 and 1942, which still exist on an adjacent parcel once part of the farm. By May, 1933, the total acreage of the Buttonwillow operation was 2,600 acres. This Buttonwillow farm was considered a satellite and supporting operation to the main San Fernando Valley farm. Apparently, the Buttonwillow farm supplied alfalfa to the primary dairy operation and also supported a herd of cattle. Adohr Farms operated the farm until the 1940s. The Adamson’s sold the Buttonwillow farm in 1948 to new owners, the Banducci and Anton families. Fred Banducci and his brother Joe operated what was known as Palm Farms at the location of the former Adohr Farms satellite operation.

By the 1950s, rice was grown in the Buttonwillow area. A rice dryer was added to Palm Farms. The rice dryer is in existence today. A 1954 Elk Hills Quadrangle clearly shows the existing landing field and hangar. The applicant suggests in their analysis that the landing field was developed concurrently with the introduction of rice fields as the airplanes would have been used to plant seed, apply fertilizer and conduct weeding.

At some point in the recent past, the property and its facilities were operated as the Port Organics fertilizer plant. There is some confusion on the part of the cultural resources and visual resources descriptions of the current and former buildings on the property. The Visual Resources section of the Amended AFC describes the former Port Organics plant as adjacent to the northwest of the project site (URS 2012a:5.11-3). It goes on to describe “the structures associated with the organic fertilizer production, such as the large grain elevators and metal storage tanks, contribute to the landscape character of the area”. Only in reviewing the Amended AFC’s Land Use section (URS 2012a:5.4-4, Figure 5.4-2[4]), does the implication become clear that the former Port Organics fertilizer plant, an industrial use, is the same property as MR 7–9, the former Adohr and

Palm Farms Complex described in the Cultural Resources section of the Amended AFC, and the large grain elevators are the aforementioned rice dryers.

According to the Amended AFC, the property is currently owned by Jomistro properties. The HECA project footprint and proposed laydown area are located on parts of what was known as Adohr/Palm Farms. An area designated as the controlled area would be located on the site of three of the remaining Adohr/Palm Farms buildings and related landscape elements. The Amended AFC does not specify what activities would take place within the controlled area. These areas are shown in URS (2012a:Figure 2-9), which is a general site plan for the proposed project. Construction disturbance is referred to in Section 2.7.1.8 and described more fully in Section 2.7.1, Project Site Construction and 2.7.1.2, Site Mobilization. It states that construction activities and site preparation work will include clearing and grubbing, site grading, stormwater/erosion control, and installation of gravel and road base for temporary roads. No specific mention is made of what existing structures or landscape features are proposed to remain, be removed or demolished. Some clarification was provided in a data response to Visual Resources Data Request No. A213 (CEC 2012a). The data request asked the applicant to “confirm whether the Plant (and all related structures, palm trees surrounding the Plant, etc.) would be removed”. The applicant responded that the “former Port Organics fertilizer manufacturing plant and all related structures will not be demolished. The surrounding palm trees will not be removed”. In fact, JRP (2012:Map 2, Sheet 4) indicates that the construction laydown area will occupy eastern portions of the site that do not have any structures or any of the resources evaluated for this project. No mention is made of the existing landing strip and hangar, or the continuation of the Main Drain, which passes through the proposed project site and the controlled area south of the project site.

The applicant divided the discussion of the built environment resources for the Adohr Farms and Palm Farms complexes into three distinct resources and recorded them separately as MR 7–9. MR 7 (Adohr Farms) and MR 8 (Palm Farms) are on the same 33.04-acre parcel. MR 9 (Adohr Farms Buttonwillow Headquarters) is on a separate 4.28-acre parcel. Staff has endeavored to relate the history and context of all three resources as a single unit while also following the individual evaluations provided by the applicant in an effort to simplify the analysis for the reader.

Historical maps have not been obtained by staff but a general outline of the boundaries of the original Adohr Farms and subsequent Palm Farms begins to emerge. On the 2,600 acres were residential buildings (**Cultural Resources Figure 7**), a collection of various agricultural buildings, a landing strip and hanger, a segment of the BVWSD Main Drain, fields, and possibly additional canals and levees. The most distinguishing feature of the farm is the perimeter plantings of Mexican Fan Palm (*Washingtonia robusta*) trees (see **Cultural Resources Figure 8**). These can be seen for miles and clearly identify the location of the farm in the flat terrain of the valley. In addition to the perimeter palms, there exists an allée of a different species of palm tree flanking Building B on the Adohr Farms property. These are likely a type of Date Palm (*Dactylifera* spp.). These mature tree plantings were not recorded on the DPR 523 forms and staff issued a data request to obtain more information about their age and history as part of the farm’s landscape. Data Request A186, issued by staff on November 2, 2012 (CEC 2012a), asked specifically for a) identification by an arborist of the genus, species and age of the trees, b) historical maps or photographs showing the farm layout, including the trees from the period of significance to the present, and c) an evaluation of the landscape features (i.e., trees and placement) significance to the site as potential character-defining features. It is, after all, known as Palm Farms.

The applicant objected to Data Request A186 on the grounds that the property was not found to be eligible and that the additional evaluation requested would not alter the eligibility conclusions drawn by the applicant. However, the objection goes on to state "while a description and estimated date for the landscape features should be included in an evaluation of an eligible property…for the trees to be contributors to the Adohr Farms property, the property as a whole must meet one of the National Register or California register Criteria and retain integrity. JRP (applicant) evaluated this property…and concluded that not only do these properties lack significance they also lacked integrity."

Staff disagrees with the notion put forward that the additional extant features, such as the distinctive palm trees on the property, should be evaluated as contributors only if the property is deemed eligible. Staff believes that a complete evaluation and recording would have included these distinctive features that may very well date to the origins of the Adohr Farm and the construction of the buildings. In fact, had the three properties making up Adohr Farms, MR 7–9, been evaluated as a district, these landscape features would have been a primary element considered in the determination of significance and integrity of the resource. The perimeter palms and the driveway allée of palms are characteristic of many California Central Valley farm landscapes, whereby the farm house and property is often marked with a boundary of planted trees and a driveway allée. Central Valley farmsteads also often feature a dense cluster of trees surrounding the primary buildings, which may include the residence, a water tower, and utility buildings. These developments and the characteristic tree plantings associated with them are often visible from several miles away, as is the case with the Adohr Farm property. The perimeter palms form a pronounced, unique silhouette that is discernible from several miles away in the open agricultural landscape. The other mature trees on the property, located adjacent to the Dairy Road extension and in the vicinity of the electric line servicing the property, are spaced in such a way that they may have at one time flanked a path or other entryway. There is another tree on the Adohr Farm property which has been heavily pollarded in the past, now appears to be dead or dying, and may be similar to the two trees with the full canopies. Staff considers the tree plantings to be character-defining features of the property and will include them in the significance evaluation.

Current parcel maps at the County of Kern Assessor's Office indicate that the driveway allée of date palms are located on Assessor Parcel Number (APN) 159-040-18-7 or 7307 Adohr Road, which includes MR 7 and MR 8.

Staff had the opportunity to tour the Adohr/Palm Farms property on September 20, 2012, with a HECA employee whose family once lived on the farm[34]. She related that her father and maternal grandparents lived and worked on the farm. He arrived circa 1950 at the age of 12 or 13. The father has a recollection of a first visit to the farm in approximately 1942 and that it was a cattle ranch at that time. This would be consistent

[34] Oral history provided by Darlena Alvidrez.

with the operation of Adohr Farms at the time. Travelling with another family from New Hope, Arkansas, the family was part of the major migration of dust-bowl refugees from Arkansas and Oklahoma (see the general history of the “Okie-Arkie” migration earlier in this section). Both families settled on the farm. The farm was known as Palm Farms or alternately, as “The Camp”. It was all one property at the time and the rice dryers were part of the complex. The white house (Building B) was the foreman’s quarters and office space. The other house (Building A) was occupied by the family members who lived and worked on the farm. It was primarily a cotton farm during this time period.

A house was removed from the property in the 1980s, possibly in July 1983. The property is described as once having a rose garden where the fence separating the two adjacent properties is now. There were more trees and many of them were suitable for climbing by the children living on the farm. Lawn areas once surrounded the residences on the property. Sanitary plumbing consisted of a septic system of which some evidence is seen on the ground in between Buildings A and B. Other household refuse was disposed of in 55-gallon barrels and burned.

Oilfield Architecture

The applicant identified the residential buildings on Adohr Farms (Buildings A & B) and Palm Farms (Residence) as similar to oilfield houses or oilfield style of architecture (Herbert and Norby 2009:4). Staff requested and received an expanded discussion of the type and style of buildings found in the oilfields of Kern County and other oil-producing regions in California. Oilfield houses were built for workers, often located on the grounds within the oil production area. The time period associated with the construction of these houses is from the late 1910s through the 1920s, and they often remained on-site until the 1930s and beyond (Mikesell and Herbert 1995). The houses were small, sometimes in a shotgun-house configuration, and were generally wrapped with porches on multiple sides. The house would typically have a pyramidal hipped roof. The upper roof covering the building would have a steep slope while the porch roof would have a shallower slope. A photograph posted on an online genealogy site shows an oilfield residence belonging to Thomas Larkins and Genevieve Erb who lived in the house from 1921 to 1933. Located in the Kern River Oilfields, the house exhibits a very steeply pitched gable roof with what appears to be a continuous open porch or veranda on all four sides. The porch roof has a very shallow pitch[35]. Oil derricks are seen in the background. This form, while it does not have a hipped roof, is otherwise in conformance with the description put forward by the applicant. Mikesell and Herbert (1995) found in their research that houses of this type were built at Kern River Oil Fields near Oildale, Camp 11-C near Taft and in the EHOF. Interestingly, Mikesell and Herbert (1995) note that the oilfield houses were very often moved once an oilfield was shut down and that they can be found all over the region.

Map Reference 7 Adohr Farms

MR 7 is a farm-related property located at 7307 Adohr Road in the PAA/APE for the proposed natural gas line, controlled area, and railroad spur. The resource includes three period buildings described in the DPR 523 form as a dormitory (Building A), dining hall (Building B) and garage (Building C), all constructed in 1930 and associated with

[35] http://freepages.genealogy.rootsweb.ancestry.com/~larkins/photos/photos13.html

the Adohr Ranch[36] (see **Cultural Resources Figure 7**). The buildings can be characterized as vernacular in style. Building A, the easternmost building, has a T-shaped footprint in a generally north-south alignment with an east-facing cross gable. Building B has a square footprint and the gabled ends above a hipped roof are aligned east-west. Building B is fronted by the date palm allée. Vertical wood paneling with battens sheath the exterior of both structures. The most distinctive feature of Buildings A and B is a central gable monitor roof above shed roofs covering porches. The monitor roofs also have clerestory ventilation slats, and in the case of Building A, gable end ventilation slats. Building B has a hipped roof. Monitor roofs are frequently found in barns throughout interior California and also in the Midwest, Appalachia, southeastern Unites States, Louisiana Cajun areas and the Winooski River area in Vermont (Noble and Cleek 1995).[37]

Both buildings' monitor roof design and side porches present a building design well-adapted to the extremes of the climate in the Central Valley. The ventilation provided by the slats in the clerestory below the main roof would have allowed heat to rise and escape from the living areas. By the same token, a blanket of cold air above the living spaces contains heat in the winter. The porches provide much needed shade in the hot, dry summer and allowed the sun, low in the sky in the winter, to provide light to the interiors. The porches also provide transition space during rainy weather.

Both buildings have fenestration in a variety of window styles including fixed pane, one-over-one, four-over-four and six-over-six double hung sashes. Building A's east wing features three sets of double French doors featuring four panes of glass in each individual door. While some of the glass is missing or broken, the windows generally appear to be original with a few later-period replacements.

The porches on Buildings A and B differ markedly in their respective railing designs. Building A has solid, vertical board siding as railings with no apparent cap or hand-rail. In places where the porch has been enclosed, there are battens placed on the vertical boards, mimicking the battens on the vertical siding of the building. As the shed gables are also treated in this way, it begs the question as to whether the railings are replacements in this case. The original design may have been the same open X-design as seen on Building B. The X pattern may be seen on at least one exterior elevation and from the interior.

Building B porch railings are an open, X-design. The cross pieces form an X boxed by a top and bottom rail. There is some deterioration of the railing on Building B in one corner; otherwise it appears intact. Screening mesh was added at some time and partially covers the porch. Building B's porch wraps around three sides of the square building.

The applicant's discussion of the buildings' style found it to be reminiscent of the style of oilfield houses, discussed above. This is due primarily to the distinctive porches and that they often had a gable on hip roof configuration, which Building B exhibits. The applicant found that the oilfield style generally predates the vernacular farm buildings on

[36] Building B has also been characterized in another account as a foreman's home and office.

[37] An example of a California barn with this configuration is seen in Caltrans (2007:Figure 82).

Adohr Farms and was limited to oilfield locations in the 1910s and 1920s. The Adohr Farms buildings A and B date to 1930.

Staff concurs that the buildings at Adohr and Palm Farms are reminiscent of the oilfield style of architecture, though the raised monitor roofs are also reflective of California barn design, as noted above. However, the stylistic similarity seems to end there as the Adohr Farms houses are larger and have more complex detailing in the eave patterns and porch designs. Therefore, Buildings A and B cannot be linked to a particular high-artistic style or broad pattern of building design. While the buildings are associated with the initially prosperous Adohr Farms operation and their owners in Southern California, this does not rise to the level of being associated with a significant person in history, locally or in California.

Staff concurs with the conclusions of the applicant for MR 7 that the property is ineligible for listing in the CRHR and NRHP. Under Criterion 1/A, the Adohr Farms buildings at 7307 Adohr Road are not significant for their association with agricultural development or settlement of the Buttonwillow area, including the immigration of dust-bowl migrants in the 1930s and 1940s. Constructed in 1930, the buildings and farm property post-date any association with Miller & Lux's ranches, even though carved out from the Miller & Lux Ranch holdings. While Adohr Farms is associated with the historical themes of agricultural development in the region and in Southern California, it alone did not make a significant contribution. Rather, it is one of numerous farming operations in the post-Miller & Lux period. Under Criterion 2/B, the buildings do not appear to be significant for their associations with any historically significant people. While Rhoda Rindge Adamson and Merritt Adamson gained recognition within the dairying industry due to the success of Adohr Farms, the Buttonwillow satellite was peripheral to their main operation in the San Fernando Valley and not representative of their holdings or dairy operation at large. The significance of Adohr Farms's commercial success is not represented in these buildings or on the property as a whole.

Under Criterion 3/C, while these buildings have some identifiable architectural details, they do not possess any distinctive characteristics or high artistic value or indication that they are the work of a master that would render them eligible under this criterion. As discussed previously, the style of the buildings is reminiscent of "Oilfield" architecture. However the construction date and function preclude them from being identified as this class of architecture. Rather, it is a modified version of this regional style. The garage (Building C) is of common utilitarian style and material. This resource is also not eligible under Criterion 4/D because it is unlikely to yield information important to history. Buildings themselves can serve as sources of important information about historic construction materials or technologies. The Adohr Farms buildings do not appear to be a principal source of important information relative to historic building technology.

<u>Map Reference 8 Palm Farms</u>

MR 8 includes a collection of warehouse buildings, four rice dryers and rice processing facility and a landing strip (**Cultural Resources Table 12**). Current (2013) imagery from Google also reveals the outlines of a former rectangular building and what appears to be the remains of the airplane hangar adjacent to the landing strip. The property is open to the Adohr Farms (MR 7) but the Adohr Headquarters Building property (MR 9) is fenced off. MR 8 was most recently home to the Port Organics fertilizer plant. As discussed earlier in the Adohr Farms history, the rice dryers and processing facility were added to the Banducci Farm in 1953. At the time the Banduccis purchased the property from the Adohr Farms, they also acquired the warehouses on the site as well as the Adohr Farms buildings (MR 7 and MR 9). The landing strip and hangar were likely added at the same time as the rice dryers to aid in the management of rice growing. Google aerial imagery also reveals an unidentified canal, drain or ditch running alongside the landing strip in a southeast to northwesterly alignment. The unnamed canal then turns to the south and proceeds through the proposed project site to the Short Main Canal south of the farm. At one time it appeared the Main Drain may have run through the project site but a conversation with the applicant’s consultant indicated that BVWSD officials stated that it stopped at a point west of Dairy Road and no longer continues[38]. Staff is not certain of the functionality or name of the canal described above and will attempt to clarify the matter for the FSA/FEIS.

The most distinctive of the buildings is the rice dryer with elevator and storage silos. Following is a list of structures associated with MR 8 and a brief description.

[38] Telephone conversation with Toni Webb, JRP Historical Consulting, January 18, 2013.

Cultural Resources Table 12
MR 8 Structures

Structure (s)	Purpose	Description
Rice processing facility	Rice drying, storage and packaging	Tall building flanked by storage silos. Metal siding, roofing and elevator. 2 metal silos and 4 concrete silos located adjacent to main structure.
Warehouse No. 1	Storage	Single-story rectangular building. Corrugated metal siding and roof. 45 ft x 150 ft
Warehouse No. 2	Storage	Single-story rectangular building. Corrugated metal siding and roof. Large open bays on south elevation. 45 ft x 150 ft
Warehouse No. 3	Storage	Single-story rectangular building. Corrugated metal siding and roof. 45 ft x 150 ft
Warehouse No. 4	Storage	Two single-story buildings joined together. Corrugated metal siding and roof. 45 ft x 300 ft
Landing Strip & Hangar	Crop-duster and other small airplanes	Dirt surface with a thin layer of asphalt. Approximately 2000 ft long by 55–60 ft wide. Hangar’s wood frame appears to be on the ground.
Shed	Storage/Other	Wood outbuilding with gabled roof with 1 window and 1 door.
Canal	Unknown	20–25 ft wide of unknown length.
Weigh Station & Warehouse No. 5[39]	Weights and measures/office/storage	Irregular rectangular footprint with front walkway and lawn and trees.

Notes: ft = feet

The names given to the structures in the table above differ from those provided by the applicant on the DPR Form for MR 8. This was done to avoid confusion with the nomenclature used for MR 7. They also provide a descriptive element that staff hopes helps the reader envision the buildings and structures being discussed. Minimal description is provided as none of the structures manifest any distinctive design details or materials that warrant a lengthy description.

Staff concurs with the applicant’s conclusion that the agricultural complex MR 8 is not eligible for listing on the CRHR or NRHP. Considering Criterion 1/A, MR 8 is not significant for its association or contribution to agricultural development in the area. While it contains one of two rice driers in the Buttonwillow area, the cultivation and production of rice in the area was short-lived and not a major agricultural development. Other than its initial association as part of the Adohr Farms complex, MR 8 is not associated with any significant historical figures under Criterion 2/B. To be eligible under Criterion 3/C, the property and its associated structures would have to possess high artistic value or be associated with the work of a master. These utilitarian buildings do

[39] Weigh station and warehouse no. 4 are later than 1973 and not of the historic period.

not meet the level required for Criterion 3/C. These buildings do not qualify under Criterion 4/D as there is no distinctive building technology employed that would lend knowledge about the history of building construction or technology.

Map Reference 9 Adohr Farms Buttonwillow Headquarters

MR 9 is a farm-related residential property located at 7345 Adohr Road. The property was originally part of the Adohr Farms complex and contains the headquarters building and a few remaining other accessory buildings. The main structure, now a residence, was constructed in 1930 as the headquarters building for Adohr Farms and has been heavily modified through conversion to a Ranch-style house. Evidence remains that the headquarters building once shared common architectural traits with the previously evaluated Buildings A and B on the MR 7 Adohr Farms property. This can be seen in the raised monitor roof, the replacement of ventilation slats with clerestory windows and the original brick chimneys. The applicant provided a historical photograph on the DPR 523 forms from 1930 which clearly shows the similarity to Buildings A and B next door[40]. Two perpendicular sections of the house form an L-shaped footprint, which appears to be the original alignment. The stucco walls enclose what originally consisted of open-air porches, shown in the historical photograph with the same open X-design of railing detail as Building B. Fenestration consists primarily of aluminum replacement windows not of the historic period. Narrow, horizontal rectangular windows are between the two rooflines as clerestory windows, replacing the original ventilation slats. There is a wide brick chimney built in almost flush with the exterior wall at each end of the house. The east side of the house has a gabled roof that extends over the driveway, forming a carport. A driveway extends from the carport north to the fence line and the access road from the Dairy Road extension. The house has taken on a ranch-style appearance from all the modifications. A small modern stucco rectangular shed with a gabled, composition shingle roof and porch on each end is on the property, west of the home. As mentioned earlier, there was apparently another house on the property that was removed in the 1980s.

This property does not possess integrity of design, workmanship, association, feeling or materials as it pertains to its original use as a farm property. It retains its location but association with the original Adohr Farms and later Palm Farms complex is not retained.

Staff concurs with the applicant and concludes that MR 9 is not eligible for inclusion in the CRHR or NRHP. While associated with the larger Adohr Farms dairy operation, the buildings at 7345 Adohr Road are not significant for their association with agricultural development or settlement of the Buttonwillow area or as a satellite operation of the dairy. The buildings post-date any association with Miller & Lux’s ranches. While Adohr Farms is associated with the historical themes of agricultural development in the region, the farm itself did not make a significant contribution. Therefore, MR 9 is not eligible under Criterion 1/A. Under Criterion 2/B, the building does not appear to be significant for its associations with any historically significant people. Although Rhoda Rindge Adamson and Merritt Adamson gained recognition within the dairying industry due to the success of Adohr Farms, the Buttonwillow satellite was subsidiary providing support to their main operation in the San Fernando Valley.

[40] *Los Angeles Times*, November 9, 1930.

When considered under Criterion 3/C, staff finds that these buildings do not possess any distinctive architectural characteristics or high artistic value that would render them eligible under this criterion. Like Buildings A and B next door, the style of the former headquarters is reminiscent of “Oilfield” architecture. The construction date and function preclude it from being of this class of architecture. The remaining outbuilding is of common utilitarian style and material, with no significant architectural features. Even if the main residence were historically significant, its historic integrity has been so heavily compromised by modifications, including enclosure of the open porch and ventilation slats, replacement windows and doors and stucco exterior cladding which all affect the original design, workmanship, materials and feeling. The building is also not likely the work of a master. Finally, the resource is not eligible under Criterion 4/D because it is unlikely to yield information important to history. Buildings can serve as sources of important information about historic construction materials or technologies. These buildings do not appear to be a principal source of important information about building technology.

Map Reference 10 Old Headquarters Weir

The Old Headquarters Weir is located southwest of the intersection of Tupman and Adohr roads, is within the proposed controlled area and process water line route. The weir is described in the DPR 523 forms completed by the applicant in 2009 and updated in December 2012. This structure, constructed in 1911, serves as both weir and bridge and crosses the Kern Valley Water Company Canal (KVWCC) at the point where that canal historically began and Outlet Canal ended.

> *Designed by consulting engineers Leonard & Day, it was constructed entirely of reinforced concrete. The structure has a flat deck, 163 feet in length and 19 feet across. Thirteen evenly spaced solid benchwalls separate 14 seven-foot-wide bays…Low walls approximately two feet high line each side of the roadway crossing the structure. A modern metal walkway was installed in the 1980s on the west side of the structure but was removed (likely pilfered for scrap metal) around 2010. Concrete patches are visible where the walkway was attached to the top of the bench walls. In numerous places the concrete has spalled revealing the rebar within…Exposed twisted steel rebar runs the length of the side walls, and notched rebar protrudes vertically near the roadway entrance on the north side. The spalling also reveals different concrete compositions on different parts of the structure. The façade is finished with a smoother finish coat than the layer beneath. (URS 2013b:Attachment A183-1.)*

In addition to the integrity issues noted above, two other changes to the weir took place over time. The weir originally was lined on both sides of the road bed with short rectangular concrete columns. On the southern exposure, each end of the bridge featured a larger square column that may have been a base for a decorative pot or other container (it is not clear from historical photographs). This square column also aligns with a concrete protrusion below it on the weir structure. Nubs of concrete still exist where the columns once were. Additionally, staff believes the roadbed may have been lowered to accomplish the creation of a low sidewall for the bridge. This is based on the observation that the original concrete column remnants (nubs mentioned above) are extant and that the side elevation view of the weir has retained the same proportions as the original seen in the historical photographs.

The weir's 14 bays were designed for the insertion of wooden slats, known as flashboards, at a roughly 30-degree angle from top to bottom to control water flow (see **Cultural Resources Figure 9**). There is a channel cut in each sidewall of the bays to accommodate the flashboards. It is a little frightening to consider how these slats would have been inserted and removed with the original configuration of the walkway having no handrail or support visible in the early photographs.

The substantial historical context provided in the DPR 523 forms includes discussion of the changes noted above. The discussion recounts a flood in the 1940–1941 rainy season that damaged the Old Headquarters Weir. It was during the repairs that followed that the concrete columns were removed and the sidewall created. The other repair documented was the replacement of the original wooden apron on the west bank with a concrete apron. A timber apron still exists on the east bank. The weir is no longer in use by BVWSD, decommissioned in 1986. It is however, still used as a bridge, providing access to the levees and canals and to other property in the area.

The DPR 523 forms provided by the applicant included a lengthy discussion of the role of Miller & Lux in establishing a system of canals and the KVWC. The Old Headquarters Weir (MR 10) and KVWCC (MR 14) are located on what was part of Miller & Lux's 52,440-ac Buttonwillow Ranch.

<u>Integrity</u>

Caltrans (2000:95) discusses the assessment of integrity as it pertains to water system elements. First, it is useful to establish a period of significance. In the case of the Old Headquarters Weir, the period of significance would be the year it was built, 1911. This is due in large part to fact that it was an early reinforced concrete combination structure designed by the well-known engineering firm of Leonard & Day in San Francisco. It is also important that Miller & Lux commissioned the weir and that it may be one of only two hybrid weir/bridge designs attributed to Leonard & Day.

The historical photographs provide a good understanding of the configuration of the Old Headquarters Weir during the period of significance. The changes made over time have been attributed to repairs made after a flood in 1941–1942. These changes in design, workmanship and materials did remove some original fabric and replaced some original materials. However, overall, there is a majority of historic fabric in place so that the integrity of materials, design and workmanship remains at a modestly high level. The setting and location have not changed. It retains the association with a water conveyance even though it is no longer in use as a weir. It continues to be used as a bridge, maintaining the association with its original purpose in that respect. It is difficult to gauge the feeling of the structure but as it retains its original location spanning a large drainage without any intrusive structures or other major changes to the surrounding landscape, it appears to have retained much of the feeling of the original structure. Where there has been some loss in feeling is in the badly deteriorated concrete walls of the structure and the neglect by its disuse. It has suffered from some graffiti and the drainage channel is used unofficially as a shotgun range, so the trash of spent shotgun shells and beer cases that adorn the channel does alter the feeling somewhat.

Even though it is badly deteriorated, staff concludes in concurrence with the applicant that the Old Headquarters Weir retains enough of the qualities of location, design, setting, materials, workmanship, feeling and association to convey its original purpose and therefore has enough integrity in addition to its association with a master engineer of the period to meet the standards for a nomination to either the CRHR or the NRHP under Criterion 3/C. It does not appear to be eligible for listing on either register under Criterion 1/A, 2/B or 4/D, as it is not associated with events contributing to the broad patterns of history, significant person(s) or yielding information on prehistory/history, even in terms of architectural or engineering developments.

Map Reference 11 California Aqueduct

The California Aqueduct is a 444-mile concrete canal that begins in the San Joaquin Valley, climbs over the Tehachapi Range and terminates in Riverside County. It is a product of the State Water Project (SWP), approved in November 1960 by a narrow margin of voters in California. The SWP originates with the Oroville Dam on the Feather River, combining flood control and water storage. The water is then moved through the Sacramento and Feather rivers to the Sacramento-San Joaquin Delta (Delta). From the Delta, water is conveyed by the California Aqueduct to Southern California. It makes water deliveries along the way through branch canals.

The first phase of the SWP, including the California Aqueduct, was constructed between 1961 and 1972, placing it within the 50-year historic period for the NRHP and the 45-year period for the CRHR. A later construction phase included the Cross Valley Canal (1973–1976).

The California Aqueduct is a concrete-lined, trapezoidal canal, measuring up to 140 feet in width and up to 40 feet deep. It is managed by the California Department of Water Resources (CDWR). In the vicinity of the project, it runs along the west side of the San Joaquin Valley, and is located approximately 1.2 miles from the center of the proposed project site and adjacent to the BVWSD West Side Canal and KVWCC. It sits at the base of the Elk Hills and is visible from portions of the OEHI property (**Cultural Resources Figure 10**). The aqueduct is located within a portion of the PAA/APE for the proposed project as well as the CO_2 pipeline.

Sections 2-63 to 2-65 of the Amended AFC describes the method of crossing for the CO_2 pipelines at the California Aqueduct, the Outlet Canal and the KVWCC (URS 2012a). HDD would be employed to pass under these canals. The HDD crossings may reach 100 feet below grade. Discussion of any possible impacts to these resources will also be discussed in the FSA/FEIS. The HDD would meet the restrictions of the CDWR California Encroachment Permit Guidelines, June 2005, which is where minimum standard of 25 feet is set for the distance between the bottom of the aqueduct channel and the top of pipe. Additionally, the construction of the CO_2 pipeline would necessitate 100-feet-by-200-feet laydown area for each crossing on either side of the water course. This laydown area would take the form of a pit of undetermined depth.

Documentation provided by the applicant includes a previously recorded inventory and evaluation by Carey & Company (2007). The applicant further updated the inventory and evaluation in December 2012 to include the segment in the PAA/APE.

Staff concurs with the conclusions of Carey & Company that the California Aqueduct is eligible for listing on the CRHR and NRHP. The period of significance extends from 1961, when construction began, through 1972, when the aqueduct was completed. It is significant for its association with SWP as a central component. This makes it eligible for listing under Criterion 1/A. It also appears to be eligible for listing in the CRHR/NRHP under Criterion 3/C as a significant engineering accomplishment.

The aqueduct does not appear eligible for listing under either Criterion 2/B or 4/D. It does not appear to be directly associated with persons who have had a significant impact at the local, state or national level, nor does it have the potential to yield information important to prehistory or history of the local area, state or nation.

Map Reference 12 6122 Tule Park Road Residence

MR 12 is the Adams' residence, a private single-family home located at 6122 Tule Park Road. It is located within the PAA/APE for the proposed HECA transmission line. The parcel is immediately west of the East Side Canal and a canal access road. Adjacent to the north is another residential property. This vernacular cottage-style house was constructed in 1941 with side-gabled roof and boxed eaves. A separately gabled lower roof on the west side of the building suggests an entrance or later addition; however, the main entrance door is located on the south side. There is one other entrance door on the east side. A gabled carport is attached to the south side of the building, above the front door. The applicant described the structure as having replacement vinyl windows and clad in vertical siding. An HVAC system is mounted on the north-facing composition-shingle roof. A newer utility structure (ca. 2008 according to Google Earth Historical Imagery) the size of a small barn is located east of the main residence. A few small trees are located on the property and the perimeter is fenced with paddock-style metal fencing.

The residence is part of a small area near the intersection of Station and Tupman roads developed sometime between 1933 and 1941, after the subdivision of the Miller & Lux holdings. Although it is located in the former Buttonwillow Ranch of land owners Henry Miller and Charles Lux, this building, constructed in 1941, post-dates any association with that period in the region's history. Martin L. Snow arrived in Buttonwillow in the mid-late 1920s. The Snow family owned a 95-acre parcel that included the property at 6122 Tule Park Road from approximately 1954 until the current owner purchased it in approximately 1994. The property changed hands between his sons, Martin Jr., and Mason from the 1950s through the 1970s. The Snows were engaged in cotton farming although it is not known whether this property was part of that activity. The applicant's survey suggests that the relatively small parcel (95 acres) on Tule Road served primarily as a residence, and not the nucleus of their farming operation. Today, 6122 Tule Park Road is a small, residential parcel owned and occupied by Thomas N. Adams.

Staff concurs with the applicant's conclusion that MR 12 is not eligible for inclusion in the CRHR or the NRHP. The building at 6122 Tule Park Road is not significant for its association with agricultural development or settlement of the Buttonwillow area. Constructed in 1941, it post-dates any association with Miller & Lux's ranches.

Staff summarizes the applicant's evaluation of MR 12, documented in a confidential appendix to the Amended AFC (JRP 2012:Appendix B) as follows.

While the residence is associated with the historical themes of agricultural development and settlement in the region, it is one of numerous farm residences built in this period and is not eligible under Criterion 1/A. The building does not appear to be associated with any historically significant people. The historical owners, the Snow family, represent one of many families who have a long history of farming in the area. Their contribution alone is not significant to local, state, or national history. Thomas N. Adams, the current owner, does not appear to be historically significant; therefore, the building is not significant or eligible under Criterion 2/B.

When considered under Criterion 3/C, the building does not possess any distinctive characteristics or high artistic value that would render it eligible. Rather it is a modest example of a popular style of house built in the mid-twentieth century. Even if the smaller building was historically significant, its historic integrity has been compromised with replacement windows and doors, composition-shingle roofing, and the reorientation of the entrance to the south, which all affect original design, workmanship, materials and feeling. The building is also not likely the work of a master. Finally, this resource is also not eligible under Criterion 4/D because it is unlikely to yield information important to history. In rare instances, buildings themselves can serve as sources of important information about historic construction materials or technologies; however, this building does not appear to be a principal source of important information in this regard.

Map Reference 13 Tupman Water Plant

Staff has not had the opportunity to conduct a site visit to the Tupman Water Plant (MR 13) and therefore includes the survey information provided by the applicant below for the PSA/DEIS (JRP 2012:Appendix B). Staff will complete a survey of the property prior to publication of the FSA/FEIS. Staff has driven by the resource to confirm its location. Using Google Earth aerial and street view imagery, staff has determined that a structure of significant size has been added to the property since the property was recorded by the applicant in 2009. Staff has confidence in the balance of the current and historical information provided by the applicant.

Located on the north side of Station Road, the property is between the East Side Canal and Morris Road. It is located directly across the street from the Tule Elk State Reserve. Structures on the site include a pump house, a new shed-type structure (ca. 2011–2012) and a water tank located on the south end of the property near Station Road. As reported on the DPR 523 forms, Getty Oil Company operates the water plant, including two wells, and it is referred to as the Tupman Water Plant. Kern County Assessor's Map No. 159-05 confirms that the parcel on which the structures are located, APN 159-050-09, is 228.98 acres total, though the structures are clustered at the southern portion of the property. There is a chain-link fence enclosing the area with the buildings and wells. The DPR 523 forms describe the pump house as having a gabled roof and corrugated metal siding. Two sliding doors and two small windows face east. The water tank is north of the pump house. The circular tank is clad with metal panels. The two wells are located in the northern part of the fenced area. An above-ground system of pipes connects the wells to the water tank. Transmission lines enter the property from Station

Road and connect to several onsite poles and to the well pumps. (JRP 2012:Appendix B.)

Like MR 12, MR 13 was developed after the dissolution of the Miller & Lux Buttonwillow Ranch. The parcel was purchased by J. S. Potter circa 1936. A residence and the metal shed (pump house) can be seen in a historical aerial photograph dating to 1937. Sometime between 1937 and 1959, the property came under ownership of oil companies (51 percent Honolulu Oil Company/49 percent Standard Oil Company). The residence was removed under the oil companies' ownership. By 1973, Getty Oil had sole ownership. An earlier tank structure was removed and the current circular tank was installed in 1981 per historical aerial imagery. (JRP 2012:Appendix B.) As mentioned above, a new building has been added to the property ca. 2011–2012.

The applicant has concluded that the property is not eligible for listing on the CRHR or NRHP under any criteria (JRP 2012:Appendix B). Staff agrees with that conclusion as the property is not associated with major historical events or people, nor does it represent any historically-recognized style or work of a master or convey any important historical information.

Map Reference 14 Buena Vista Water Storage District Features

Buena Vista Water Storage District Canals

BVWSD formed in 1924 and assumed ownership and management of the canal system developed by Miller & Lux between 1876 and 1918. The system stretches from the second point of measurement on the Kern River to Buena Vista Lake and then northwest along the former Buena Vista Slough to Tule Lake. **Cultural Resources Figure 3** exhibits the drains, canals, ditches and Old Headquarters Weir associated with the district and within the PAA/APE. This figure also shows the California Aqueduct, which is part of the SWP, discussed above under MR-11.

The canals, drains and ditches still in use in the BVWSD have generally northwesterly flows. This follows the original natural flow direction of Buena Vista Slough on the west side of the valley. The canals, ditches and drains are maintained by BVWSD by grading twice per year and excavation every 5–10 years. These features are summarized in **Cultural Resources Table 13**.

Cultural Resources Table 13
Buena Vista Water Storage District Features

Name	Description	Materials	Size[41]
Cass Ditch	Trapezoidal earthen canal (lateral).	Earthen with culverts.	Top: 20 ft Bottom: 5 ft Depth: 5 ft Length: 1.5 mi
Depot Drain	Trapezoidal earthen canal (lateral).	Earthen with structures, culverts, etc.	Top: 15 ft Bottom: 3 ft Depth: 3 ft Length: 5.9 mi
Deep Wells Ditch	Trapezoidal earthen ditch (lateral).	Earthen ditch with steel structures, delivery gates, headwalls, etc.	Top: 30 ft Bottom: 9 ft Depth: 9 ft Length: 4.7 mi
East Side Canal (Miller & Lux)	Trapezoidal canal.	Earthen with steel structures, check gates, etc.	Top: 45–60 ft Bottom: 25–27 ft Depth: 10–12 ft Length: 24.1 mi
Kern Valley Water Company Canal (KVWCC)	Irregular trapezoidal/rounded earthen canal/flood channel.	Vegetated earthen canal, crossed by Old Headquarters Weir. West Side Canal Inlet.	Top: 220 ft Bottom: 150 ft Depth: 12–15 ft Length: 26.8 mi
Outlet Canal	U-shaped earthen canal.	Mostly dry, vegetated earthen canal crossed by Tupman Road Bridge.	Top: 220 ft Bottom: 120–150 ft Depth: 15 ft Length: 9 mi
Short Main Canal	Trapezoidal earthen ditch (lateral).	Earthen ditch with control gate ca. 2010-2011, Tupman Road Bridge.	Top: 50–60 ft Bottom: 25–36 ft Depth: 12 ft Length: 1.3 mi
West Side Canal (Miller & Lux)	Trapezoidal earthen ditch.	Earthen ditch with miscellaneous structures.	Top: 60 ft Bottom: 33 ft Depth: 8 ft Length: 26.4 mi
KRM 001H[42]	Ditch and water gates	Concrete lined ditch with miscellaneous structures.	Top: 5 ft Bottom: 1 ft Depth: unknown Length: 2,780 ft

Abbreviations: ft = feet; mi = mile(s)

The following text provides historic context for the system extending north of the Old Headquarters Weir northwest to SR 58 bounded by the East Side Canal on the east and West Side Canal on the west. An overall description of each canal is included in the

[41] Sizes are taken from the DPR 523 Form submitted by the applicant and are approximate.

[42] Recorded by Farmer (2008).

following evaluation discussions for each point surveyed, grouped by canal. These structures were built between1876–1918; alterations and improvements are made every one to two years up to the present. The historic context below was provided by the applicant in the DPR 523 forms for MR 14, BVWSD (URS 2013b:Attachment A185-1).

<u>Lux v. Haggin</u>

Miller & Lux's attempts to control the Buena Vista Slough through construction of the KVWCC played a role in the events that led to the landmark water rights case, Lux v. Haggin. Canal construction was completed in 1878, and Miller & Lux found themselves with a massive canal bed that had no water and 10,000 head of cattle facing starvation. Although 1876–1877 had been a drought season, they quickly identified upstream diversions of water from the Kern River as the cause of their water scarcity. In the years just prior to the arrival of the railroad, irrigationists diverting water from the Kern River had a number of canals either planned or under construction to water their lands in western Kern County.

[Miller & Lux] formed the Riparian Suits Association as their legal arm and began filing actions against Haggin, Carr, and other upstream diverters to stop their consumption of the river's flows before it reached lands Miller & Lux et al. claimed to be riparian lands. [The Lux v. Haggin] case at first was a far-reaching conflict that included, as either plaintiff or defendant, what appeared to be most of the principal landowners and water users in the region. Ultimately, control of Kern River water was hammered out in an 1888 compromise that became known as the Miller-Haggin agreement. Amendments have been made to the agreement over the years, but it is still a basic document regarding division of water in the area.

The system [of canals] created during the Miller & Lux period consisted of canals dug and maintained by Miller & Lux, and a system of laterals dug and maintained by individual tenant farmers. After constructing a main flood control canal [KVWCC] along the west side of the swamp, Miller & Lux also constructed East Side and West Side canals for distribution, sometime prior to the early 1890s. As their names indicate, these canals bordered the east and west sides of Buttonwillow Ranch, with West Side Canal running closely parallel to the KVWCC. Much smaller than the flood canal, the West Side Canal was only 30 feet wide and two feet deep, and the East Side Canal was 25 feet wide and three to five feet deep. [Between 1916 and 1918,] Miller & Lux also constructed a drainage canal, called Main Drain, from the southern end near the old headquarters northerly through the center of the ranch, generally along the line of the original Buena Vista Slough. Farmers used the water from Main Drain, collected primarily by seepage, for irrigation. The remainder of the canals and laterals in the area, like Deep Wells Ditch, [Weed Island Ditch, and Arizona Canal (formerly Poplar Grove Ditch),] were primarily works of individual farmers and Miller & Lux farm divisions in the area, who connected to the main canal system for irrigation of their crops.

The canal system allowed Miller & Lux to support settlement in the area. By 1919, Miller & Lux farmed the entire area south of Buttonwillow between the East Side and West Side canals south to Old Headquarters. Four ranches were established in the area adjoining major canal works.

Miller & Lux, Incorporated had accumulated valuable land and water rights. However, neither was profitable without the other. [To] sell the land, a means of attaching water…to the land was necessary. In 1920 the California State Engineer released a report on the water resources of the Kern River and recommended that a large district, including the Haggin and Miller & Lux water rights, be formed to manage water distribution. Despite the effective implementation of the Miller-Haggin agreement, the two parties chose to protect their interests by forming separate districts. Miller & Lux's holdings became the nucleus for the BVWSD. The district submitted a petition for formation to the State Engineer in 1922 and received approval in 1924. As a part of the district formation, Miller & Lux allocated water rights to the land within the district, making future sales possible. The district exchanged bonds with Miller & Lux for the existing canals and sold additional bonds for construction of new canals…The district acquired all the canals in the study area, including flood water canals, irrigation canals, drainage canals, and associated water control features.

Despite the changing crops in the study area, the extensive network of canals constructed during the Miller & Lux period remained a largely sufficient source. With the advent of groundwater pumping, farmers used the canals to move water from the wells to their fields, a practice that continues today. Between 1943 and 1944, 4.8 miles of new drains were constructed in the water storage district…Culverts and bridges added as the road system developed were insufficient to keep the water flowing. Redwood culverts and corrugated metal pipe culverts, some installed by Miller & Lux, began to be replaced. The BVWSD also instituted a canal maintenance program in 1943 that called for regular hand maintenance, and mechanized maintenance every four years.

Below is an evaluation of each of the water conveyance features within the PAA/APE identified in **Cultural Resources Table 13**. The bulk of the following analysis was provided by the applicant (JRP 2012; URS 2013b) with modifications by staff.

Cass Ditch (CD)

Cass Ditch is a lateral with an unknown construction date. BVWSD acquired Cass Ditch from Miller & Lux and others, in 1936. When the ditch was acquired by BVWSD, it was over 2 miles long and extended from the East Side Canal to present-day Dunford Road, then turned north. There have been abandonments and realignments to the portion north and west of Dunford Road since 1964.

Staff concurs with the applicant's conclusion that the Cass Ditch is not eligible for the CRHR or NRHP under Criterion 1/A. It is not significant for its association with irrigated agriculture around Buttonwillow. It is not significant for its association with Miller & Lux or others under Criterion 2/B. It is representative of its time period but it lacks integrity, does not display any high artistic values and is not related to the work of a master, therefore it is not eligible under Criterion 3/C. Lastly, Cass Ditch does not yield any important design or construction techniques that would inform history or prehistory. It is ineligible under Criterion 4/D.

Depot Drain (DD)

The Depot Drain is a farmer-dug lateral on the eastern side of BVWSD. Depot Drain was not one of the existing canals acquired by BVWSD in 1926. Rather, portions of its current route appear as two separate ditches in mapping from the early 1930s. The path of the drain meandered through the east side of the district. By 1942, the ditches were joined, the drain named, and the path of the ditch was closer to its modern route, cutting in straight diagonals through fields and following roads along cardinal directions. Additional straightening has occurred through the period between 1954 and 1973. Currently, the ditch is 5.9 miles long. It cuts a 1-mile path directly west before heading northwest for the remainder of its length. When the drain reaches SR 58 to the north, it heads west and feeds into Main Drain. The ditch is conveyed under roadways via round culverts and water is deposited into the canal by corrugated pipes that collect water in the fields. A short segment of the Depot Drain is located within the PAA/APE for the proposed railroad spur.

The portion of the drain within the PAA/APE is between Dairy Road and Dunford Road to the west. DD as documented by the applicant is a point where the ditch intersects with Dunford Road, approximately 0.25 mile north of Stockdale Road. This segment of Depot Drain is a narrow trapezoidal earthen canal. The north side is higher than the south. The drain is conveyed under Dunford Road via a round corrugated metal pipe.

Staff concurs with the applicant's conclusion that the Depot Drain is not eligible for the CRHR or NRHP. Under Criterion 1/A, the drain is not significant for its association with irrigated agriculture around Buttonwillow. The drain is one of several laterals constructed by BVWSD following the subdivision of Miller & Lux holdings. At that time, irrigated agriculture had already been practiced in the area for more than 40 years. Under Criterion 2/B, the drain is not significant for its association with any individual, having been constructed by BVWSD. Under Criterion 3/C, the canal was constructed using standard methods of the time period. One could argue that this canal lacks integrity to any historical period of significance, owing to its regular realignment, reshaping, and replacement of control structures. However as discussed earlier with the headquarters weir, maintenance and upgrades alone are not enough to disqualify the resource if it still conveys its intended use and design, feeling and location. This resource is also not eligible under Criterion 4/D because it is unlikely to yield information important to history. In rare instances, structures can serve as sources of important information about historic construction materials or technologies; however, the water conveyance does not appear to be a principal source of important information in this regard.

Deep Wells Ditch (DWD)

Deep Wells Ditch, historically also known as Deep Wells Canal, was associated with the irrigation of Miller & Lux' Deep Wells Ranch. It originated from the East Side Canal and between Stockdale Highway and Brite Road it divided into three paths, one of which connected to Depot Ditch near Deep Wells Ranch. When the BVWSD acquired the canal in 1926, it was approximately 6 miles long. The ditch was originally consolidated along its eastern path, connecting with Depot Drain and then Main Drain. Between 1937 and 1952, it was rerouted along its western route paralleling Main Drain. Today, the canal ends closer to the point of the former Deep Wells Ranch and measures approximately 4.7 miles long. Two small farm bridges cross the canal along Stockdale Highway, providing access to residential homes. As the canal continues northwest of Stockdale Highway, a few farm bridges cross it, and there are a few concrete check gates along the length. One segment of the Deep Wells Ditch along Stockdale Highway between Dairy Road and Dunford Road is located within the PAA/APE for the proposed railroad spur.

Staff concurs with the applicant's conclusion that the Deep Wells Ditch is not eligible for either the CRHR or NRHP. The canal is one of many farm-dug laterals constructed during the Miller & Lux era, providing needed drainage and irrigation. Deep Wells Ranch was one of several satellite ranches in the Buena Vista Slough under the management of the Buttonwillow headquarters. Therefore, under Criterion 1/A, the canal is not significant for its association with irrigated agriculture around Buttonwillow. Under Criterion 2/B, the ditch is not significant for its association with any individual, having been constructed by the company of Miller & Lux rather than the individuals themselves. Under Criterion 3/C, the canal was constructed using standard methods of the time period. This resource is also not eligible under Criterion 4/D because it is unlikely to yield information important to history. In rare instances, structures can serve as sources of important information about historic construction materials or technologies; however, the water conveyance does not appear to be a principal source of important information in this regard.

East Side Canal (ES)

The East Side Canal was constructed by the KVWC under the direction of S. W. Wible in the late 1870s. Initially, the East Side Canal was to serve as the primary irrigation canal for the Buttonwillow Ranch, while the KVWCC was to drain the slough on the western side. In 1898, the canal was 25 feet wide and 3–5 feet deep. At its intake from the Buena Vista Slough, a regulating gate with vertical flashboards controlled water flow and also functioned as a road bridge. As of 1920, the East Side Canal had a 25-feet-wide timber flash board head gate that served as an intake from Outlet Canal. Starting in 1918 through at least 1920, Miller & Lux had extensive work done to the canal. A levee was constructed along the East Side Canal north of the Southern Pacific Railroad tracks running through Buttonwillow. Extensive excavation was performed on the canal to increase the working capacity of the canal from 100 feet per second to 300 feet per second throughout. When BVWSD acquired East Side Canal in 1926, the canal was 27 miles long and served as the main artery on the east side of the district, supplying, with few eastern exceptions, irrigation canals on its west side. The wooden control features constructed by Miller & Lux have been replaced with concrete structures.

The East Side Canal forms the eastern boundary of BVWSD and also borders the western boundary of the Tule Elk Reserve. It feeds laterals and receives drainage water from the ditches on the eastern side of the district. It runs in a northwesterly direction for approximately 24.1 miles from its origin at a diversion weir to its terminus at Goose Lake Canal. Concrete check gates are located along its width and culverts transport it under roads. The East Side Canal is located within the PAA/APE for the proposed transmission line and railroad spur.

Staff concurs with the applicant's conclusion that the East Side Canal is not eligible for the CRHR/NRHP. Like the KVWCC (evaluated below), the East Side Canal was one of several contributing factors for the litigation. Under Criterion 1/A, the East Side Canal lacks historical significance for its association with the Lux v. Haggin litigation. Under Criterion 2/B, the ditch is not significant for its association with any individual, having been constructed by the company of Miller & Lux rather than the individuals themselves. The canal was constructed using standard methods of the time period and is not a master work of S. W. Wible. Therefore, this resource is not significant under Criteria 3/C. This resource is also not eligible under Criterion 4/D because it is unlikely to yield information important to history. In some instances, structures can serve as sources of important information about historic construction materials or technologies; however, the water conveyance does not appear to be a principal source of important information in this regard.

<u>Kern Valley Water Company Canal (KVWCC)</u>

The KVWCC is an earthen canal constructed in 1874. After KVWC was organized for the reclamation of the Buena Vista Slough, S. W. Wible was put in charge as engineer. The massive size of the canal he engineered for them was intended to drain the water of the Kern River from the slough and also feed irrigation laterals. When first constructed, it extended 26 miles northwesterly up the slough from Old Headquarters, had a top width of 250 feet, bottom width of 125 feet, and a depth of 7 feet. By 1893, the canal was 12 feet deep. A series of four numbered timber weirs built on the KVWCC regulated the flow of water. Approximately 4 miles apart, each weir could be closed, forming a reservoir whose water could then be channeled into canals for distribution. The weirs also functioned to slow the flow of water down the canal as it proceeded northwesterly up the slough. In the early years of the canal, flood waters from the Kern River posed a constant threat to the canal's water control features. In 1878, within three months of the canal's completion, water split its head gates. An 1898 map indicates four weirs along the canal, but Grunsky's 1898 water supply report that year states that three of the four weirs were washed out, leaving only one remaining. These were subsequently replaced by the Old Headquarters Weir, discussed in detail previously as MR-10. In 1914, Miller & Lux and the Carmel Cattle Company collaborated to improve the irrigation system on the Buttonwillow Ranch. Their primary concern was the northern 6-mile stretch of the KVWCC that had been deemed inadequate for proper flood control. The new section of canal became known as the Kern Valley Reclamation Company's Canal. When BVWSD acquired the canal and its associated water control features, they identified the KVWCC as both asset and liability because floodwaters had eroded the channel to hundreds of feet wide in places.

Today this waterway is known as the Flood Channel, which accurately describes its current use. No longer used for drainage or irrigation, the channel only receives overflow waters in years of heavy flooding. The channel begins at Old Headquarters Weir and follows a winding path for approximately 26.8 miles in a northwesterly direction along the western boundary of BVWSD, paralleling the West Side Canal. The canal is bounded on the east by the West Side Canal. Flooding in the 1970s and 1980s required substantial maintenance of the canal to remove debris and control vegetation.

The western side is levied above the surrounding topography with soil removed from the channel. Reshaping by bulldozers traveling perpendicular to the canal has resulted in a U-shaped cross section. Floodwaters have cut meandering paths in the bottom of the canal and left silt in other areas. Staff has made site visits to the KVWCC in the vicinity of Old Headquarters Weir and found the channel to be full of vegetation and some debris.

The KVWCC is located within the PAA/APE for the proposed CO_2 line, at the southern end of Dairy Road. This segment is a roughly U-shaped canal that is 180 feet wide at the top, 100 feet wide at the base, and 15 feet deep. The path of the canal is irregular. The southern side is built up and resembles a levee or sand bar in areas. The height of this southern side is irregular and undulating, with a gentler slope into the canal. The Old Headquarters Weir crosses the canal at this point. East of the weir is an inlet to the West Side Canal, via the Short Main Canal. The inlet has a concrete head wall and flanking walls. A square metal gate is raised and lowered by a screw mechanism. The gate leads to an underground culvert connecting the two canals.

Staff concurs with the applicant's conclusion that the KVWCC is not eligible for the CRHR or NRHP. The KVWCC, East Side Canal, and West Side Canal, constructed in 1876, along with the Kern Island Canal (ca. 1870) and Calloway Canal (1874–1875), precipitated the seminal Lux v. Haggin litigation, which has shaped California water rights. However, on their own the KVWCC, East Side Canal, and West Side Canal are not significant for their role in the litigation. The upstream canals diverting water before it reached Miller & Lux' property also had a crucial role in setting the scene of the conflict. One particular canal or water diversion alone could not have been entirely responsible for Lux v. Haggin. Numerous conditions converged in Kern County to produce this fierce litigation over water. Some of these include: the shifting course of the Kern River, the construction of numerous canals and ditches diverting water from the river, and the competing interests of two large-scale landholders combined produced lengthy litigation. For these reasons, the KVWCC is not eligible under Criterion 1/A.

While the canal was constructed under the auspices of Miller & Lux, it is not directly associated with either of those individuals. Miller & Lux constructed numerous canals throughout their holdings to irrigate feed crops. While Henry Miller did visit most of his holdings, including Buttonwillow, most of his time was spent in San Francisco or his home ranch, which are more appropriately associated with him and the business. Therefore, the canal is not significant under Criterion 2/B. The canal was designed by S. W. Wible, a civil engineer who designed mines in El Dorado, Amador, and Calaveras counties before coming to Kern County, where he designed the Pioneer and Wible canals before designing the KVWCC. Despite his engineering knowledge, the KVWCC is not an engineering success and is not significant for its design or construction. Therefore, the canal is not significant under Criterion 3/C. This resource is also not eligible under Criterion 4/D because it is unlikely to yield information important to history. In some instances, structures can serve as sources of important information about historic construction materials or technologies; however, the water conveyance does not appear to be a principal source of important information in this regard.

<u>Outlet Canal</u>

To convey water from Buena Vista Lake to KVWCC, Miller & Lux constructed the Outlet Canal. Upon completion of the East and West Side Canals, the Outlet Canal became a source of water for those two canals as well. The Outlet Canal followed the general alignment of the Buena Vista Slough, meandering northward to the original Weir No. 1 at the old headquarters. In 1919 the flow of the Outlet Canal was controlled by two wooden weirs, one near Buena Vista Lake and the other at the East Side Canal. The Outlet Canal ceased its function in the 1970s as a source for the East and West Side canals and the KVWCC. It is normally dry and occasionally used for groundwater recharge.

Staff concurs with the applicant's conclusion that the Outlet Canal is not eligible for the CRHR or NRHP. The canal lacks historical association with Lux v. Haggin litigation, although it was one of several contributing factors for the litigation. The lack of direct association makes it ineligible under Criterion 1/A. Under Criterion 2, the Outlet Canal is not directly associated with a significant person. The Outlet Canal is not an example of a type, period or method of construction nor an example of the work of a master, making it ineligible under Criterion 3/C. This property is not likely to be a source of important information regarding history, and therefore not eligible under Criterion 4/D.

Short Main Canal

The Short Main Canal crosses east to west at the southern edge of the proposed project boundary. It was originally constructed in the nineteenth century as an addition to the Main Canal by KVWC. BVWSD obtained the right-of-way from Miller & Lux in 1929. Delivering water from the East Side Canal to the West Side Canal, it is also a source of irrigation water for adjacent farmlands. Control gates located at the east and west confluences are of modern design.

The canal lacks historical association with Lux v. Haggin litigation, therefore it is not eligible under Criterion 1/A. Not being associated with a significant person, Short Main Canal is not eligible under Criterion 2/B. Neither representative of a type, period or method of construction, nor associated with the work of a master, Short Main Canal is ineligible under Criterion 3/C. The canal does not appear to be source of important information regarding human history and therefore is ineligible under Criterion 4/D.

West Side Canal (WS)

The West Side Canal was built by Miller & Lux in the 1890s to collect, distribute and drain water. The canal was wide and shallow, approximately 30 feet wide and 2 feet deep. Miller & Lux records indicate problems with the planned system in 1916. A rapid program of expansion, lengthening the canal north of its former terminus and reconstructing the wooden head gates, was undertaken to provide enough water for the 1917 crops. Additional construction and maintenance under the control of BVWSD has replaced the weirs and head gates of the canal with modern concrete structures. The water supply for the canal has also been altered. Water entered the canal from the Outlet Canal to the southeast. However, after 1973, the Outlet Canal was removed as a source and water now enters the canal from the Short Main Canal that connects the East Side and West Side canals.

Currently, the West Side Canal is a main canal of BVWSD. It is a trapezoidal earth-lined irrigation canal that runs approximately 26.4 miles in a northwesterly direction from its origin where it branches off from Short Main. It parallels the flood channel that forms the western boundary of BVWSD. The canal acts as a main artery for the system, receiving water from drainage ditches, and supplying water to irrigation laterals. The canal slowly narrows along its path. Near its origin, it is approximately 60 feet wide and 12 feet deep.

West Side Canal also receives water at two points from the California Aqueduct, which runs nearby to the south. With the exception of Eighty-Foot Ditch, which West Side Canal feeds directly into, the canal supplies the laterals through diversion gates. Few roads cross the canal over bridges and the canal is supplied with concrete check gates. There is a short segment of the West Side Canal located within the PAA/APE for the proposed CO_2 line and the process water line is proposed to run alongside the canal.

At the southern end of Dairy Road and at the intersection with Short Main Canal, the West Side Canal is a well maintained, earth lined ditch with trapezoidal cross-section. A concrete check gate with three bays controls the flow of water into the canal and also serves as a bridge. From here, the canal flows in a northeasterly direction alongside the KVWCC.

Staff concurs with the applicant's conclusion that the West Side Canal is not eligible for the CRHR or NRHP. Under Criterion 1/A, the West Side Canal lacks historical significance for its association with the Lux v. Haggin litigation. Like the KVWCC, it was one of several contributing factors for the litigation. Under Criterion 2/B, the canal is not significant for its association with the individual partners of Miller & Lux. The canals are a result of the organization, not the individuals. Under Criterion 3/C, the canal was constructed using standard methods of the time period and is not a master work of S. W. Wible. This resource is also not eligible under Criterion 4/D because it is unlikely to yield information important to history. In some instances, structures can serve as sources of important information about historic construction materials or technologies; however, the water conveyance does not appear to be a principal source of important information in this regard.

<u>KRM-001H</u>

KRM-001H is a historic period ditch segment adjacent to the West Side Canal. Originally recorded by Farmer (2008), the information was not resubmitted for the current project. It appears to fall within the PAA/APE. It is described as a ditch mostly lined with weathered concrete. At the time of its recording the ditch appeared to be in use. Modern water gates have been added to the ditch and it appears to be connected to other canals. Staff observed this ditch on a site visit in September 2012, but did not survey it as it had not been identified as a resource in the current application. The 2008 recording draws no conclusions as to its eligibility for listing on the CRHR or NRHP. The significance of KRM-001H will be fully analyzed for the FSA/FEIS.

Map Reference 15 Tule Elk State Reserve

Tule Elk State Reserve was established as a State Parks unit in 1954. But its history goes back to the Civilian Conservation Corps (CCC) in the 1930s and the damming of the Kern River at Lake Isabella. In 1930, Miller & Lux provided 600 acres to establish a temporary holding area for the tule elk, which had developed a sizable herd in the area. Then, a 958-acre reserve was established by the California State Park Commission in 1932.

In 1934–1935, CCC cleared the land, built a road, an adobe house and various amenities suitable for a ranger's residence and park headquarters. The reserve operated at this location for the next three decades. Construction of the Isabella Dam had the effect of greatly limiting seasonal flooding in the Buena Vista Slough at the southern edge of the reserve. The habitat in which the elk had thrived disappeared and the elk suffered as a result.

California State Parks constructed replacement facilities closer to Station Road in 1956. The circular drive, ranger's residence, office/shop, Quonset hut, sheds, picnic shelters, and restroom building appear in a 1974 aerial photograph. The viewing platform and equipment shelter appear after 1991. It is not known when the prefabricated visitor center building was added. **Cultural Resources Table 14** summarizes the structures constructed on the property after the 1956 move of operations to the north end of the property.

Cultural Resources Table 14
Tule Elk State Reserve Structures

Structure	Purpose	Description
Office/Shop Building	Office/Shop	Rectangular footprint, concrete foundation, board and batten siding, gable asphalt sheathed roof, wide boxed eaves with exposed purlins. Windows have six-light awning pane over three-light fixed pane.
Shed	Equipment Shelter	Attached to Office/Shop. Three bays and a corrugated metal shed roof.
Shed	Flammables Storage	Concrete block walls with overhanging gable roof with open ventilation. Door centered on north side.
Shed	Storage	Board and batten siding, overhanging roof with open eaves. Louvered vents in gable ends and a door centered on south side.
Quonset Hut	Storage	Corrugated metal with full-height panel sliding door on the flat side and a four-light steel awning window on each end.
Residence Building	Ranger’s residence	Wide rectangular footprint, board and batten siding, shallow pitched side gable roof with boxed eaves and exposed purlins. The front entry is recessed and centered on the primary façade. Windows are vinyl sliders. South end has a single car garage with a tilt-up aluminum door.
Visitor’s Center	Visitor’s center with displays	Prefabricated trailer on a raised pedestal with Americans with Disabilities Act (ADA)-accessible ramp entry. Plywood siding and aluminum sliding windows.
Viewing Platform	Covered platform for viewing elk herd	Steel and wood open platform with shingled roof. Raised above ground. ADA accessible ramp. Interpretive panels.
Restroom Building	Bathrooms and large covered patio	Board and batten siding. Large mural of an elk on east side. Roof extends over concrete open area likely used for interpretive talks.
Picnic Shelters	Shade shelters	Steel side poles in a V-pattern support steel beam supports for solid roof cover. Sited on a concrete pad with adjacent barbeque grill. Shelters are located in a shaded lawn area.

The CCC-era adobe is extant on the property at the southern end but has deteriorated physically. The amenities and recreational facilities constructed by the CCC are concealed by the overgrowth that has taken place in the last 50–60 years. The adobe itself, however, retains a great deal of its design details, location and materials. The adobe and related landscape elements might have local significance in the context of land conservation efforts and CCC activities. However, since the adobe and the associated grounds are outside of the PAA/APE, staff will not complete an evaluation for the resource.

Staff concurs with the applicant's conclusion that the resources within the PAA/APE are not eligible for listing as historic resources on the CRHR or NRHP. While some of the structures date to 1956, placing them within the historic period, they are not associated with the original conservation efforts of the reserve and therefore not eligible under Criterion1/A. The property does not inform or illustrate the significance of the land owners Henry Miller and Charles Lux and has been managed by California State Parks since 1954. Therefore, it is not associated directly with persons of significance and ineligible under Criterion 2/B. The structures within the PAA/APE do not appear to be the work of a master nor do they represent a recognizable style or trend in architecture or park design. The mid-century overtones are nothing more than vernacular building styles. Therefore, none of the structures are eligible under Criterion 3/C. Lastly, the structures within the study area do not appear likely to be a source of information about history and are not eligible under Criterion 4/D.

JRP-HECA-4 Landing Strip and Hangar

This resource lies partially within the PAA/APE for the proposed railroad spur, but was not submitted with the 2012 amended application. Staff became aware of the previous evaluation late in the discovery period and has not had the opportunity to review the DPR 523 forms and evaluation for the PSA/DEIS. In its evaluation, the applicant does not find it eligible for listing on the NRHP/CRHR. Staff analyzed the resource in 2011 and concluded that site JPR-HECA-04, the airfield and hangar, is not eligible for inclusion in the CRHR.

Site JRP-HECA-04 is an airfield and a hangar located just east of 2534 Wasco Way and was constructed between 1954 and 1973. The site is on the remnant of a dirt airfield dating from the late 1950s. The prefabricated steel hanger has an arched roof. The wall away from the former airstrip is covered with corrugated metal and has a single personnel door set near the north edge. The opposite end has two sliding doors that were once supported by a top beam extending beyond the top width of the arch. Other buildings that had occupied the site were victims of a recent fire.

Air travel developed as a form of transportation and a means of managing crops during the 1920s. Kern County developed a municipal airport in 1925 outside of Bakersfield. Continuing enthusiasm for aircraft and flight led to the development of a countywide system of airfields approved by the Civilian Aviation Administration in 1946. In 1958 the system included 15 airfields across the county. Companies and large landholders also found it convenient to develop their own airfields. Five airfields, including the Buttonwillow-Kern County Airfield (off Elk Hills Road), were constructed between 1954 and 1973. These airfields supported crop dusting and private aircraft. This airfield is among the smallest and is not paved. The airfield has a single metal arch hanger manufactured by several manufacturers.

Typically, industrial properties that are evaluated as CRHR-eligible achieve that status by way of their association with important events or movements or unique or breakthrough engineering or technologies or architecture (that is, eligibility under Criterion 1 or 3). They rarely are associated with a person important in California history and typically do not have scientific value under Criterion 4 that is not included in Criteria 1 or 3.

Staff concludes that site JPR-HECA-04, the airfield and hangar, is not eligible for inclusion in the CRHR. Evaluated under Criterion 1, the airfield is not significant for its association with the development of flight, an event important in the broad pattern of California history. The airfield is a common rural resource used for crop management and private flights and is one of many built in the county during the same period. The airfield is not associated with a significant individual and is a construct of a large company; therefore, it does not appear to be eligible under Criterion 2. Under Criterion 3, the site does not embody a distinctive type, period or method of construction. The field is unpaved and the hangar is a prefabricated building of common construction. This resource is also not eligible under Criterion 4 because it is unlikely to yield information important to history. In rare instances, buildings themselves can serve as sources of important information about historic construction materials or technologies; however, the airfield does not appear to be a principal source of important information in this regard.

Summary of CRHR-Eligible Built Environment Cultural Resources for the HECA Project

Staff found that one built environment resource (California Aqueduct) had already been determined eligible for both the NRHP and the CRHR. Staff concurs with this previous determination. Staff considers one built environment resource, the Old Headquarters Weir (HECA-JRP-24/MR 10), to be eligible for the CRHR and NRHP, making it a historical resource under CEQA and a historic property under Section 106 of the NHPA. (see **Cultural Resources Table 15**.) However, staff finds the remaining 21 built environment resources ineligible for the CRHR and NRHP.

Cultural Resources Table 15
CRHR/NRHP-Eligible Cultural Resources Potentially Subject to Impacts from the Proposed Project

Resource	Type	Project Element	Eligibility
Built-Environment Resources			
Old Headquarters Weir (MR 10)	Bridge and Weir over KVWCC	CO_2 line	Eligible
California Aqueduct	Canal	CO_2 line	Eligible

Isolated Finds

A total of 18 isolated finds have been identified in the HECA portion of the PAA/APE (**Cultural Resources Table 16**). Isolated finds are rarely considered historical resources, unique archaeological resources, or historic properties under CEQA and Section 106 of the NHPA. This PSA/DEIS, therefore, does not assess the proposed project's impacts on the isolated finds identified in **Cultural Resources Table 16**.

Cultural Resources Table 16
Isolated Finds within the PAA/APE: HECA Project Elements

Resource Number	Description	Location	CRHR and NRHP Status	Siting Case Report Reference
BS-IF-001	Two pieces of debitage	Process water line	Ineligible under CEQA & NRHP	Farmer 2008:Table 5-1; HEI, with URS 2008:5.3-46
BS-IF-002	Flake	Process water line	Ineligible under CEQA & NRHP	Farmer 2008:Table 5-1; HEI, with URS 2008:5.3-46
BS-IF-003	Flake	Process water line	Ineligible under CEQA & NRHP	Farmer 2008:Table 5-1; HEI, with URS 2008:5.3-46
JM-IF-001	Flake	Process water line	Ineligible under CEQA & NRHP	Farmer 2008:Table 5-1; HEI, with URS 2008:5.3-46
KRM-IF-002	Core	Process water line	Ineligible under CEQA & NRHP	Farmer 2008:Table 5-1; HEI, with URS 2008:5.3-46
KRM-IF-004	Flake	Process water line	Ineligible under CEQA & NRHP	Farmer 2008:Table 5-1; HEI, with URS 2008:5.3-46
KRM-IF-005	Two pieces of debitage	Process water line	Ineligible under CEQA & NRHP	Farmer 2008:Table 5-1; HEI, with URS 2008:5.3-46
HECA-ISO-2	Two pieces of debitage	CO_2 line	Ineligible under CEQA & NRHP	Farmer 2008:Table 5-1; HEI, with URS 2008:5.3-46
Isolated Artifact 1	Biface	CO_2 line	Ineligible under CEQA & NRHP	Stantec 2011:8
HECA-2009-ISO-1	Projectile point	Controlled area	Ineligible under CEQA & NRHP	Hale and Laurie 2009:39, Appendix C
HECA-2009-ISO-2	Scraper	Project site	Ineligible under CEQA & NRHP	Hale and Laurie 2009:39, Appendix C
HECA-2009-ISO-3	Biface	Project site	Ineligible under CEQA & NRHP	Hale and Laurie 2009:39, Appendix C
HECA-2009-ISO-4	Core	Controlled area	Ineligible under CEQA & NRHP	Hale and Laurie 2009:39, Appendix C
HECA-2009-ISO-5	Projectile point	Project site	Ineligible under CEQA & NRHP	Hale and Laurie 2009:39, Appendix C
HECA-2009-ISO-6	Projectile point	Controlled area	Ineligible under CEQA & NRHP	Hale and Laurie 2009:39, Appendix C

Resource Number	Description	Location	CRHR and NRHP Status	Siting Case Report Reference
HECA-2009-ISO-7	Flake tool	Project site	Ineligible under CEQA & NRHP	Hale and Laurie 2009:39, Appendix C
HECA-2009-ISO-8	Flake	Controlled area	Ineligible under CEQA & NRHP	Hale and Laurie 2009:39, Appendix C
HECA-2009-ISO-9	Handstone	Controlled area	Ineligible under CEQA & NRHP	Hale and Laurie 2009:39, Appendix C

EOR Project Elements

Prehistoric Archaeological Resources

Staff considered five individual prehistoric archaeological resources that would be subject to direct impacts from the OEHI CO_2 line, and finds that all five could not be evaluated because the applicant provided insufficient data for staff to make significance determinations. In Data Requests A85–88 staff requested additional cultural resources information regarding the OEHI CO_2 line, processing facility, associated processing satellites, 150 new wells and 652 miles of pipeline. This additional information includes: a record search, a literature review, copies of site forms for previously recorded sites, copies of reports describing previous cultural resources studies in the project vicinity, a pedestrian survey, and a technical report presenting the results of the survey. Staff understands that OEHI is in the process of collecting the requested information. Evaluations of any resources identified during these surveys, if any, will be presented in the FSA/FEIS.

CA-KER-5401 (P-15-6776), HECA-2008-6, HECA-2008-7, HECA-2008-11, and HECA-2008-12

These archaeological sites are situated in the proposed CO_2 line alignment and have been described in the previous subsection, “HECA Project Elements”.

Ethnographic Resources

No NRHP/CRHR-eligible ethnographic resources have been found in the PAA/APE.

Historic Archaeological Resources

During the September 19–20, 2012 site visit to the proposed project, staff examined the vicinity of the proposed CO_2 processing facility. Here, staff identified a historic archaeological site consisting of disarticulated fire bricks, glass fragments, milled lumber, and metal artifacts. Staff temporarily designated the site CO2-2012-1 and drew it to OEHI personnel’s attention to ensure that the site was recorded and evaluated. Staff understands that OEHI has conducted additional fieldwork in the proposed EOR components and may have resolved this issue, per Data Requests A141–146 (CEC 2012b:8–13). At the time of this writing, however, staff has not received this information. Therefore staff was unable, on the basis of the information provided, to determine if CO2-2012-1 is eligible for the NRHP or CRHR. Staff will present OEHI’s latest methods and findings, and staff’s analysis, in the FSA/FEIS.

Built-Environment Resources

Staff has reviewed previous Energy Commission Cultural Resources analysis for the Elk Hills Power Project (EHPP), which is located on the OEHI property (CEC 2000a). The following historic setting discussion is excerpted from this previous record. Early in the twentieth century the U.S. Navy expressed to Congress their concern for the strategic security of the nation's oil supply, and requested creation of defined petroleum reserves. In September, 1912, an executive order signed by President Taft created NPR-1, covering about 38,000 acres in the Elk Hills. Leases were acquired from the Navy by Standard Oil and speculators, and as the industry expanded in this remote area, families of many workers relocated to privately owned camps in the Elk Hills. Standard Oil's facility at Tupman not only supported field activities, but provided many residential amenities.

Concerned that such growth would deplete the government's reserve, the Navy undertook to drain the leased fields from offset wells, and to reclaim the leased resources. All claims had reverted to the government by 1938. Production was greatly increased during World War II, both to generate revenue and to supply naval needs. The Navy's Construction Battalions (Sea Bees) moved onto NPR-1 to operate the wells, make improvements, and conduct wartime readiness drills, digging foxholes and building bunkers. These features survive on the northeast and northwest flanks of the oil and gas field (Nachmanoff et al. 1999). Additional episodes of oil development followed in 1945, 1951, and 1976. The DOE operated NPR-1 (now the EHOF) until February 1, 1998.

The Section 106 consultation process for the transfer of NPR-1 from DOE to private hands culminated in the execution of a programmatic agreement (PA) and Cultural Resources Management Plan (CRMP), both in force for approximately three years from the time of execution. The CRMP devotes a single page to the historical resources and does not offer a research design. Section 2 of the CRMP lists three historic era properties (three Hay wells) that are eligible for listing in the NRHP. Section 2.1 identifies further research to be done, and Section 2.2 refers to a historical publication to be prepared for public distribution. The maps provided as Appendix 2 to the CRMP depict the prehistoric sites exclusively. (Jackson and Shapiro 1998.) As described in the EHPP AFC, known historic era built environment cultural resources of potential interest or concern would include transportation corridors and facilities; oil and gas production locations and installations; homesteads; commercial and residential communities, as represented by buildings, other structural elements and discards; work camps; sites; districts; landscapes; and objects (EHPP 1999; Nachmanoff et al. 1999).

Built Environment Reconnaissance and Survey of NPR-1/OEHI

NPR-1, now operated by OEHI, is the location of the proposed EOR, and staff analyzed it as part of the proposed project. In preparing this PSA/DEIS, staff reviewed the research, evaluations and conclusions of previous Energy Commission Cultural Resources staff for the EHPP, which is located on the OEHI property (CEC 2000a). At that time staff noted that the EHPP AFC did not contain any architectural or engineering analysis of evidence remaining of the long history of oil production or the work camps which supported industrial activities. Although much of the oil and gas production equipment in the project vicinity was older than 45 years at the time of the EHPP AFC, and at least one historic site within the EHPP project area contained materials dating back at least to the 1920s and probably older, based on the presence of sun-colored amethyst glass, the structural elements, artifact deposits and research potential of historical remains were not assessed. The EHPP AFC described a work camp site, for example, that contained a complex of foundations, roads and trails, privies, at least three trash deposits, railroad grades, walls and fences. This site, which included comparable examples with both industrial and residential remains, and numerous wells spudded in during the 1920s were regarded as disturbed because superstructures were fragmentary or missing. Seemingly for this reason alone, these sites were evaluated as failing to meet the criteria for significance. The archaeological and engineering/technological aspects of such sites were not addressed, and historical landscape was not considered.

Naval Petroleum Reserve No. 1 (NPR-1)

NPR-1 was the subject of a historical resources evaluation and assessment report (Hamusek-McGann et al. 1997) at the time of the transfer of the property from DOE to Occidental Petroleum, parent company of OEHI. The report assessed both historic archeological resources and built environment resources. Several periods of significance were found in the report, including Early Exploration (1910–1918), Initial Development Rush (1918–1930), Depression Years (1930–1941) and the War Years (1941–1946). The report authors identified the Elk Hills Rural Historic Industrial Landscape as a historic property eligible for the NRHP under Criterion A. The SHPO took issue with this conclusion, calling into question the landscape's integrity. The SHPO wrote, "For no period of significance does the property today exhibit enough integrity in all applicable categories to readily convey its historic appearance…" (Widell 1997:1). Apparently, the report lacked identification of the landscape's character-defining features, which would have bolstered Hamusek-McGann et al.'s (1997) contention that it is NRHP-eligible.

Staff visited the NPR-1/EOR area on September 19, 2012. Many of the early period (1910–1941) built environment features which might have been contributors to a district appear to be missing, damaged or altered. However, there are two areas that appear to have integrity and warrant further survey and evaluation: World War II Military Sites and Check Dams.

World War II Military Sites

Hamusek-McGann et al. (1997) provides some documentation of Navy activity during the war years and the activities of the Sea Bees (Construction Battalions or CBs) in particular. According to Hamusek-McGann et al. (1997), the Sea Bees constructed roads, drill pads, wells and military trenches, bunkers and other defensive earthworks on the north and west flanks of the landscape. Of these activities, the trenches, bunkers and other earthworks appear to be intact (**Cultural Resources Figure 11**). These earthworks seem to be located in primarily in the low oil-production areas of Elk Hills and this may contribute to their high degree of integrity. Hamusek-McGann et al. (1997) found that the relationship of the trenches to the topography offers an insight into the military's approach to defensive positions on the ground during this period. The report states that physical evidence of defensive infrastructure during WWII is rapidly disappearing, increasing the value of NPR-1 military sites, which may be eligible as historic properties under NRHP Criterion A.

Check Dams

During staff's site visit, OEHI staff pointed out a series of check dams constructed on the property meant to control the flow of water off the site to the valley below. These check dams appear to have a design that incorporates a metal pipe that siphons the water through an earthen dam, at a point below the water level of the dam, allowing water to pass through the pipe and leaving any oily residue to collect at the bottom of the basin. This in effect reduces the potential for oil to flow beyond the property boundary during a rain event or a spill. These check dams are prevalent throughout the site and it is not known when these dams were constructed or by whom. Hamusek-McGann et al. (1997) report that WPA crews were on site during the Depression years constructing culverts, laying pipeline, repairing equipment and constructing roads. The check dams are not discussed in the report and their origin is not known by staff. They are a landscape element specifically relating to this site's topography and function and require evaluation to determine their contribution to the overall landscape, their association with one of the historic periods noted above and if they qualify as historic resources under CRHR or NRHP.

KRM-010H Soil and Gravel Road

KRM-010H is a historic period oil-road traversing the southeastern portion of the OEHI property, not far from the toe of the slope and the path of the California Aqueduct. It was recorded by Farmer (2008) for the original HECA AFC. It is described as an oil-topped road running diagonally in a northeast to southeast direction. It may have been associated with the Sea Bees due to artifacts found nearby. The road is approximately 1 mile long and 24 feet wide. The segment seems to channelize water along its length and had been badly eroded when recorded in 2008. Staff was unaware of this potential historic built environment resource as it was not included in the current project application. Staff will gather more information for the FSA/FEIS.

Isolated Finds

Two isolated finds have been identified in the EOR portion of the PAA/APE (**Cultural Resources Table 17**). Isolated finds are rarely considered historical resources, unique archaeological resources, or historic properties under CEQA and Section 106 of the NHPA. This PSA/DEIS, therefore, does not assess the proposed project's impacts on the isolated finds identified in the table.

Cultural Resources Table 17
Isolated Finds within the PAA/APE: EOR Project Elements

Cultural Resource Type	Description	Location	CRHR and NRHP Status	Siting Case Report Reference
HECA-ISO-2	Two pieces of debitage	CO_2 line	Ineligible under CEQA & NRHP	Farmer 2008:Table 5-1; HEI, with URS 2008:5.3-46
Isolated Artifact 1	Biface	CO_2 line	Ineligible under CEQA & NRHP	Stantec 2011:8

Summary of NRHP/CRHR-Eligible Resources for EOR Project Elements

As stated earlier in this subsection of the PSA/DEIS, the results of the cultural resources inventory of the EOR project elements has not yet been provided to staff. This prevents staff from providing a full analysis of the proposed project's likelihood of causing significant adverse effects to historical resources, unique archaeological resources, and historic properties in the PAA/APE. Nevertheless, staff is able to offer a provisional analysis based on the information gathered so far.

Currently, six archaeological resources are known to exist in the PAA/APE: CA-KER-5401 (P-15-6776), HECA-2008-6, HECA-2008-7, HECA-2008-11, HECA-2008-12, and CO2-2012-1. Each requires a significance evaluation that takes into account the sites' current degree of historic integrity as well as the close proximity of the sites to one another. Based on information provided to date, staff considers these six archaeological sites to be historical resources under CEQA and historic properties for the purposes of Section 106 of the NHPA.

Additionally, staff has identified two previously unrecognized sets of historic built environment resources that are associated with Hamusek-McGann et al.'s (1997) proposed Elk Hills Rural Industrial Historic Landscape and a historic road, all of which may constitute historical resources under CEQA and historic properties for Section 106 purposes.

Staff will make firm significance determinations upon receipt of the EOR cultural resources inventory report and backing documentation. Staff will present its findings in the FSA/FEIS.

As stated previously in this PSA/DEIS, isolated finds are rarely considered historical resources, unique archaeological resources, or historic properties. The EOR isolated finds are no exception in this regard.

DIRECT/INDIRECT IMPACTS AND MITIGATION

Construction Impacts and Mitigation

Identification and Assessment of Direct Impacts on Archaeological Resources and Proposed Mitigation: HECA Project Elements

Surface Archaeological Resources

Staff has concluded that 18 prehistoric resources, one historic archaeological site, and two multi-component archaeological sites will be subject to direct impacts from the proposed HECA project elements. The applicant has not conducted the fieldwork required to gather data for site eligibility determinations for prehistoric sites which would be impacted by the proposed project. Without primary field data on the presence of a subsurface component for these sites, staff cannot evaluate them sufficiently to determine if they may retain the potential to yield information important to prehistory. Therefore, staff was unable to determine if these 21 known sites are eligible for the CRHR or NRHP, assess the impacts of the proposed project on known and unknown resources, or propose mitigation for any significant effects.

The applicant proposes to avoid damaging the following archaeological resources by placing the proposed process water pipe on the ground surface next to the northeastern side of the West Side Canal's levee in the vicinity of the sites and covering the pipeline (and a portion of the archaeological resources) with fill dirt.

- HECA-2009-10
- P-15-171 (CA-KER-171)
- HECA-2009-09
- HECA-2008-1 (JM-BVWD-1)
- P-15-179 (CA-KER-179) and KRM-IF-003
- (URS 2013c:147-1)

To this list staff adds:

- BS-IF-004
- P-15-7176/P-15-6725
- CA-KER-2485 and BS-IF-003

The applicant assumes that placing the pipe on the ground surface, burying it in fill, and burying or capping a portion of known archaeological sites in the process would negate any significant impacts on the resources. Although capping the sites in fill sediment would afford some protection to the sites, burial in fill has the potential to compromise archaeological (or historical) integrity. In the context of archaeological resources along the proposed process water line, potential sources of impacts on archaeological resources include damage to and displacement of artifacts from construction traffic, artifact damage from compression as heavy equipment crosses the sites, and damage to archaeological materials resulting from scarification (usually accomplished by disking), should such preparation be required to properly anchor the placed fill (Thorne 1991:6). In addition, mitigation measures like intentional site burial need to be done with a mind toward long-term resource management, which requires knowledge of a site's character-defining features before a firm decision can be made to bury the archaeological site under fill (Thorne 1991). Presently, the applicant does not have these data. In many cases, obtaining these data would require presence/absence test excavation, and possibly test and data recovery excavations. Therefore, staff finds that the proposed project would likely result in damage to the archaeological resources in the two bullet lists immediately above. Accordingly, staff has requested that the applicant provide information that permits to determine the significance of these archaeological resources. Supplying this information would be a multi-step process that would inform staff's analysis in the FSA/FEIS. The first step would entail the applicant preparing and submitting to staff an archaeological research design for scientific excavation and documentation of the known archaeological resources in the PAA/APE. Upon staff review and approval of the research design, the applicant would implement the research design and prepare an excavation report containing their significance recommendations to staff. Once the applicant provides an excavation report that is acceptable to staff, Energy Commission staff will have information sufficient to analyze the proposed project's impacts on the subject archaeological resources in the FSA/FEIS.

CEQA advises a lead agency to make provisions for archaeological resources unexpectedly encountered during construction, and a project owner may be required to train workers to recognize cultural resources, fund mitigation, and delay construction in the area of the find (Pub. Resources Code, §21083.2; 14 Cal. Code Regs., §§15064.5(f) and 15126.4(b)). Consequently, staff recommends that procedures for identifying, evaluating, and possibly mitigating impacts to archaeological resources discovered during construction be put in place through conditions of certification to reduce those impacts to a less than significant level.

Buried Archaeological Resources

The proposed project would be built in areas considered to have a moderate to high potential to contain well-preserved, buried cultural materials. These materials would be expected within 35 feet of the modern ground surface on the valley floor and within 3 feet of the modern ground surface in the Elk Hills. Therefore, all proposed HECA ground-disturbing activities have the potential to substantially and adversely change the CRHR/NRHP-eligibility of archaeological deposits that may lie buried in the PAA/APE. The applicant will conduct additional geoarchaeological field explorations to establish a factual basis for the assessment of potential effects to buried deposits within the project limits. Staff and the applicant are working on a geoarchaeological research design to address this data gap and expect that the data will be available for the FSA/FEIS.

Identification and Assessment of Direct Impacts on Ethnographic Resources

Neither the applicant nor staff has identified ethnographic resources in the PAA/APE. Staff tentatively concludes that the proposed project would not result in impacts on ethnographic resources. No conditions of certification (conditions) or mitigation measures are recommended with respect to ethnographic resources.

Identification and Assessment of Direct Impacts on Built-Environment Resources and Proposed Mitigation

One built environment resource (California Aqueduct) has previously been determined eligible for both the NRHP and the CRHR. Staff concurs with this previous determination. Staff considers one built environment resource, the Old Headquarters Weir (HECA-JRP-24/MR 10), to be eligible for the CRHR and NRHP (**Cultural Resources Table 18**). However, the remaining 21 built environment resources are not eligible for the CRHR or NRHP.

Cultural Resources Table 18
Affected CRHR/NRHP-Eligible Historic Built Environment Resources

Resource	Type	Project Element	Eligibility
Built-Environment Resources			
Old Headquarters Weir (MR 10)	Bridge and Weir over KVWCC	CO_2 line	Eligible
California Aqueduct	Canal	CO_2 line	Eligible

Staff concludes that there appears to be less-than-significant impacts to the two eligible historic properties listed in **Cultural Resources Table 18** above. The only potential for direct impacts to the Old Headquarters Weir and the California Aqueduct is through the construction of the CO_2 pipeline leading from the HECA project site to the OEHI CO_2 processing facility.

Section 2-63 to 2-65 of the Amended AFC describes the method of crossing for the CO_2 pipelines at the California Aqueduct, the Outlet Canal and the KVWCC (URS 2012a). HDD would be used to build underneath the aforementioned canals. These HDD crossings may reach 100 ft below grade. The HDD would meet the restrictions of the CDWR California Encroachment Permit Guidelines, June 2005, which sets a minimum standard of 25 ft for the distance between the bottom of the aqueduct channel and the top of pipe to prevent damage to the conveyance. Additionally, the construction of the CO_2 pipeline would necessitate 100-ft-by-200-ft laydown area for each crossing on either side of the watercourse. This laydown area would take the form of a pit of undetermined depth.

As the CO_2 pipeline crossings would take place underground, it is unlikely to impact the Old Headquarters Weir, which spans the KVWCC in the immediate vicinity of the proposed crossing. The construction laydown areas which would accompany the HDD drilling on either side of the crossings would be finalized in the maps submitted as compliance with Condition of Certification **CUL-2**. The proposed crossing under the California Aqueduct would not damage this historical resource/historic property if the best practices as set forth in the CDWR California Encroachment Permit Guidelines, June 2005, are followed. Implementation of these best practices is required in Condition of Certification **CUL-2.**

Identification and Assessment of Direct and Indirect Impacts on Cultural Resources and Recommended Mitigation: EOR Project Elements

Surface Archaeological Resources

An unknown number of prehistoric sites (minimally CA-KER-5401, HECA-2008-6, HECA-2008-7, HECA-2008-11, and HECA-12) are located in the EOR portion of the PAA/APE and may be subject to direct or indirect impacts. The applicant has not conducted the fieldwork required to gather data for site eligibility determinations for prehistoric sites that may be impacted by the proposed EOR facilities. Without primary field data on the presence of a subsurface component for these sites, staff cannot evaluate them sufficiently to determine if they may retain the potential to yield information important to prehistory. Therefore staff was unable to determine if these sites or others (as-yet-unidentified) are eligible for the CRHR or NRHP, assess the impacts of the proposed EOR facilities on known and unknown resources, or propose mitigation for any significant effects. The applicant is preparing to submit the cultural resources inventory report and supporting documentation to staff; this information will be discussed in the FSA/FEIS.

Buried Archaeological Resources

The proposed EOR facilities would be situated in areas considered to have low to moderate potential to contain well-preserved, buried cultural materials. These materials would be expected within 3 feet of the modern ground surface in the Elk Hills. The erosional nature of the hills renders it unlikely that buried archaeological materials are present in the EOR portion of the PAA/APE without evidence of their presence on the ground surface. Therefore, staff does not recommend further geoarchaeological study of the proposed EOR facilities.

Historic Built Environment Resources

Data responses from the applicant are pending for the OEHI World War II military sites and check dams noted above (also see **Cultural Resources Table 19**). Until that information is received and staff has an opportunity to evaluate the resources and the potential project impacts, staff is unable to assess specific impacts to these resources or propose mitigation if necessary.

Cultural Resources Table 19
EOR Built Environment Resources Eligibility

Resource	Type	Project Element	Eligibility
NPR-1	Rural historic landscape important in local and state history for development of the petroleum industry. Unknown number of contributors subject to impacts.	CO_2 line and processing facility, EOR area	Not eligible
KRM-010H	Soil and gravel road	CO_2 line and processing facility	Unknown
WW II Military Sites	Military earthworks and structures	CO_2 line and processing facility	Unknown
Check Dams	Surface water control structures	CO_2 line and processing facility	Unknown

Indirect Impacts

Construction of the electrical interconnection between the proposed HECA project and the Midway–Wheeler Ridge Transmission Line would require installation of optical control grounding wire along the transmission line between the proposed HECA switching station and Midway Substation in Buttonwillow. Additionally, the proposed project would necessitate installation of a 500/220-kV transformer bank and ten 80-kA breakers at Southern California Edison's Mesa Substation in Pasadena, Los Angeles County. Staff is presently reviewing the cultural resources information (records search results) collected for the Midway–Wheeler Ridge Transmission Line. Staff will present an analysis and conclusions in the FSA/FEIS.

Operation Impacts and Mitigation

With respect to direct impacts, if, during operation of the HECA and OEHI projects, the project owners should plan any changes or additions entailing significant amounts of ground disturbance, the project owner would have to petition the Energy Commission to review the environmental impacts of those activities and approve the plan. Cultural resources staff would then determine if previously undisturbed sediments would be affected by the planned activities and, if so, recommend the application of existing conditions or devise new ones to mitigate any impacts to significant known or newly identified cultural resources. Consequently, at this time staff has recommended no conditions of certification addressing operation direct impacts.

Environmental Justice Impacts

Staff has identified minority environmental justice populations in the 6-mile HECA buffer; the Buttonwillow, Bakersfield, and Wasco census designated places; and the Bakersfield, Buttonwillow, Shafter, Wasco, and West Kern census county divisions (see **Socioeconomics Table 2**). According to the 2010 U.S. Census, the minority populations in these areas are Hispanic or Latino populations (U.S. Census 2010). Staff has not identified historic properties, historical resources, or unique archaeological resources in the PAA/APE that are culturally important to Hispanic or Latino populations. As stated in the "Environmental Justice/Socioeconomic Methods" of this PSA/DEIS section, staff has not identified a Native American environmental justice population in the PAA/APE. Staff cannot conclude at this time, however, that the proposed project would not cause environmental justice impacts related to cultural resources because the applicant has not completed its efforts to identify cultural resources in the PAA/APE. Staff will complete its environmental justice impacts analysis for cultural resources after receipt of reports on a complete cultural resources inventory and present the analysis in the FSA/FEIS.

Cumulative Impacts and Mitigation

A project may result in a significant adverse cumulative impact where its effects are cumulatively considerable. "Cumulatively considerable" means that the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects (14 Cal. Code Regs., §15130; see also 36 C.F.R., part 800.5[a][1]; 40 C.F.R., §1508.7). Cumulative impacts to cultural resources in the project vicinity could occur if any other existing or proposed projects, in conjunction with the proposed project, had or would have impacts on cultural resources that, considered together, would be significant. The previous ground disturbance from prior projects and the ground disturbance related to construction of the proposed project and other proposed projects in the vicinity could have a significant cumulative effect on subsurface archaeological deposits, both prehistoric and historic. The alteration of the setting which could be caused by the construction and operation of the proposed project and other proposed projects in the vicinity could also have a significant cumulative impact to cultural resources.

Staff has proposed conditions of certification providing for identification, evaluation, and avoidance or mitigation of impacts to previously unknown archaeological resources that may be discovered during the construction of the proposed project and qualify as historical or unique archaeological resources under CEQA, or historic properties under Section 106 of the NHPA.

For the purposes of this cumulative impacts analysis, staff has determined that the cumulative area of analysis comprises that portion of the upper San Joaquin Valley that the Buena Vista Slough once drained, as well as the Elk Hills. This area stretches from Wasco south to Maricopa, and from the Temblor Range east to the eastern edge of Bakersfield and the Kern Lake vicinity, approximately a 20-mile radius from the proposed project site (see **Cultural Resources Figure 12**). Staff selected this area for cumulative impact analysis because it forms a geographic unit that was probably meaningful to the prehistoric human inhabitants of the project vicinity and encompasses a similar range of cultural resource types throughout: agricultural properties, oil extraction and processing, water conveyance, and occupation sites. Accordingly, the 20-mile radius from the project site forms a useful basis for assessing cumulative impacts on related resource types. In selecting projects that could contribute to cumulative impacts, staff identified those projects in the 20-mile radius that would result in ground disturbance because excavation is the primary vehicle for cultural resources impacts for the proposed projects. Staff presents its list of cumulative projects for cultural resources in **Cultural Resources Table 20**.

Cultural Resources Table 20
Summary of Cumulative Projects—Cultural Resources

Project Title	Location	Project Description	Resources Affected/Level of Significance	References
Maricopa Sun Solar Complex Project	East of Maricopa	At least two photovoltaic power generating stations on 9,027 ac; possible construction of a weather station	14 cultural resources/LTS	Armstrong et al. 2010; Kern County 2010
FRV Valley Solar Project	Bakersfield, Arvin, and Lamont	Construct and operate three solar photovoltaic power generating facilities on three sites totaling 1,063 ac in unincorporated portions of Kern County	Three cultural resources affected, none significant/LTS	Crawford 2012; Holm 2011a, 2011b; Holm and Jackson 2011; Kern County 2012a; Planning Commission 2012a; Tejada 2012
General Plan Amendment/Zone Change 12-0372	Bakersfield: Rosedale Highway and Van Buren Place	General Plan Amendment and Zone Change on approximately 20.41 ac. Develop multifamily housing with a maximum of 225 dwelling units	Unknown, although ground-disturbance during construction could damage cultural resources/Potentially significant impact	
Northern Area Project	Kern County: Between Imperial Road and SR 46	Convert ~18 linear miles of canal with ~25 mi of pipeline from open earthen canals to a closed or semi-closed system	At least three known prehistoric sites and conversion of canals and pipelines could affect historic canals and irrigation features/Potentially significant impact	Staff records search map
Old River Solar Project	Bakersfield: Shafter Road, between Gosford Road and Ashe Road	Construct and operate contiguous solar facilities on two parcels. The Old River One solar facility would be located on ~ 188 ac, while the Old River Two facility	No cultural resources affected/LTS	Hudlow 2011; Kern County 2012b; Planning Commission 2012b

Project Title	Location	Project Description	Resources Affected/Level of Significance	References
		would be located on ~ 33 ac		
Strand Ranch Integrated Banking Project	Kern County: Stockdale Highway and Enos Lane (SR 43)	Deliver up to 6,5000 acre-feet of SWP water to the Strand Ranch Integrated Banking Project in Kern County	No cultural resources affected/LTS	ESA 2008
Berry Petroleum Company Project	Kern County	Install gas fired steam generators and five steam generators at the existing McKittrick Oilfield (21Z Lease)	No cultural resources affected/No impact	SJVUAPCD 2012
General Plan Amendment/Zone Change 12-0349	Bakersfield Region: Panama Lane and Stine Road	General Plan Amendment and Zone Change on approximately 56.19 ac; develop duplex and multifamily housing with a maximum of 617 dwelling units	Unknown, although construction-related digging could affect cultural resources/Potentially significant impact	
North Shafter Project	Wasco: SR 46 and Root Avenue, SR 46 and Leonard Avenue	Drill and test four exploratory oil/gas wells near the community of Wasco outside the Rose Oil Field	No cultural resources affected/LTS	Brunzell 2011; DOGGR 2012
Pioneer Green Solar Project	McCombs Road and Corcoran; Starrh (private road) and Lokern Road	Construct and operate three solar electrical generating facilities on 720 ac	Five isolated artifacts, non-significant/LTS	Kern County 2013; Planning Commission 2013; Shaver 2012; Shaver and Baksh 2011
San Joaquin Rail Corridor 2035 Vision Project	Kern, Sacramento, San Joaquin, San Francisco, Los Angeles, Merced counties	San Joaquin Rail Corridor infrastructure upgrades	Potentially significant impact	Caltrans 2012a
SR 58 Gap Closure	Bakersfield: Between SR 99 and Cottonwood Road	Road widening	No cultural resources affected/No impact	Caltrans 2012b

Project Title	Location	Project Description	Resources Affected/Level of Significance	References
SR 58 Widening Project	Bakersfield: West of Allen Road to SR 99	Road widening and restriping	15 cultural resources (historic built environment) affected, none NRHP/CRHR-eligible/No impact	Caltrans and City of Bakersfield 2012
Westside Parkway Project	Bakersfield: Allen Road, Calloway Drive, Coffee Road, Mohawk Street	Site preparation, planting of vegetation and installation of minimal irrigation	30 cultural resources affected, one NRHP/CRHR-eligible/LTS	USDOT et al. 2006
Zone Change 15, Map 140; PD Plan 5, Map 140; Exclusion from Ag Preserve 10; Tentative Parcel Map 11235	Bakersfield: Enos Lane, Taft Highway (SR 119)	Development of an oilfield equipment staging/storage area and warehouse of two portions of an 80-ac vacant parcel	Unknown; two cultural resources located near SW corner of intersection/Potentially significant impact	Staff records search map

Note: ac = acre(s); LTS = less than significant; mi = mile(s); SR = State Route

The cultural resources information for the 15 projects identified in **Cultural Resources Table 20** varied significantly: staff was unable to locate environmental documents or other cultural resources information on two projects, possess partial records search data for two projects[43], and located environmental and cultural resources documents for 11 of the cumulative projects. As the table shows, environmental reviews found that three of the projects would not result in impacts on cultural resources. Environmental impact assessments concluded that seven of the tabulated projects would result in a less-than-significant impact on cultural resources, with the implementation of resource-specific mitigation measures and standard conditions on the proposed projects. The remaining five cumulative projects have the potential to result in a significant impact to cultural resources. Of these, only the proposed San Joaquin Rail Corridor project is the subject of an environmental document that finds a significant environmental impact on cultural resources. Concerning the general plan amendment and zone changes for the project at Rosedale Highway and Van Buren Place and Panama Lane at Stine Road, staff assumes that the proposed projects have the potential to result in significant impacts on cultural resources because of the lack of information available to staff at the time of this writing. Staff's consultation of its records search map of the HECA vicinity resulted in the identification of recorded and unrecorded cultural resources in or near the Northern Area Project and proposed oilfield equipment staging at Enos Lane and Taft Highway. With the assessment of HECA's potential impacts on cultural resources currently incomplete, staff is unable to conclude whether incremental effects on cultural resources would be cumulatively considerable when viewed in conjunction with the projects in **Cultural Resources Table 20**. The FSA/FEIS will have a complete cumulative impacts analysis.

[43] Staff's records search map for these two cumulative projects consists of drawn boundaries and basic identifying labels for previous cultural resources studies and known cultural resources.

COMPLIANCE WITH LORS

At the present state of impact analysis, if the conditions of certification (below) are properly implemented, the proposed HECA project would tentatively result in a less-than-significant impact on known and newly identified CRHR/NRHP-eligible resources. However, as discussed in "Summary of Conclusions" and "Unresolved Areas Related to Cultural Resources", applicant-provided cultural resources information leaves staff with considerable data gaps, such as a near-absence of project-specific analysis for the EOR project elements. Nevertheless, staff understands that a cultural resources inventory of the EOR project elements has been completed and the results will be submitted to the Energy Commission. Additionally, staff continues to work with the applicant to resolve other data gaps in the present analysis, such as geoarchaeological assessment of the proposed project and significance evaluations of archaeological resources. The scope of studies underway and planned is consistent with the requirements of applicable LORS. Staff therefore tentatively concludes that the project would be in compliance with all applicable LORS listed in **Cultural Resources Table 1**. Specific justification for staff's conclusions in this regard is contained in the following two paragraphs.

Concerning federal LORS, Energy Commission staff has worked with DOE personnel to consult with tribes, identify and evaluate cultural resources, assess impacts, and determine appropriate mitigation measures. Staff's activities were conducted in concert with the DOE to maintain compliance with federal requirements. Specifically, DOE personnel have initiated consultation with federally recognized tribes by letter and participated in an EOR site visit with the Tejon Indian Tribe, as described previously in this document (see the "Historical Resources Inventory/Native American Consultation" subsection). The DOE has also initiated consultation with the SHPO ("Historical Resources Inventory/Consultation with Others"). Cultural resources identification work for the proposed project was conducted at the direction of personnel who meet the Secretary of the Interior's standards for professional archaeologists, historians, and ethnographers; all staff responsible for preparation of this PSA/DEIS also meet the Secretary of the Interior's professional standards. Staff's proposed conditions of certification (see "Conclusions and Recommendations"), drafted in coordination with the DOE, further comport with federal preservation objectives. Therefore, if HECA implements these conditions, its actions would accord with the cultural resources management priorities of the federal government.

Kern County's General Plan and the Western Rosedale Specific Plan have language promoting the general county-wide preservation of cultural resources, CEQA compliance for discretionary projects, and notification of Native Americans about discretionary projects of concern to them. Additionally, the Interstate 5 at Highway 58 Rural Community Plan and Oglesby Specific Plan contain requirements for developers to stop work for not less than 72 hours in the event of inadvertent archaeological discoveries during construction, to facilitate assessment of the discovery and mitigation of impacts. (City of Bakersfield 2007; Kern County Department of Planning and Development Services 1986:30; Kern County Planning Department 1994:II-13, II-14; Kern County Planning Department 2009:66–67; Rickett, Ward and Delmarter 1985:14, 15.) Staff's proposed conditions of certification here will require specific actions not just to promote but to effect historic preservation and mitigate impacts to all cultural resources in order to ensure CEQA compliance. Consequently, if HECA implements these conditions, its actions would be consistent with the cultural resources-related goals of Kern County.

DEPARTMENT OF ENERGY (DOE) FINDINGS REGARDING DIRECT AND INDIRECT IMPACTS OF THE NO-ACTION ALTERNATIVE

Under the No-Action Alternative, DOE would not provide financial assistance to the applicant for the HECA Project. The applicant could still elect to construct and operate its project in the absence of financial assistance from DOE, but DOE believes this is unlikely. For the purposes of analysis in the PSA/DEIS, DOE assumes the project would not be constructed under the No-Action Alternative. Accordingly, the No-Action Alternative would have no impacts associated with this resource area.

RESPONSE TO COMMENTS

Staff has not received any comments on cultural resources from the public. Staff has identified several comment letters from other agencies where some mention is made of cultural resources. Of these, only the NAHC and SHPO provided specific comments on staff's efforts to assess the proposed project's effects on cultural resources. The NAHC indicated to staff that the NAHC's Sacred Lands File does not contain record of Native American cultural resources in the project vicinity (see ”Energy Commission Native American Consultation”, earlier in this document). During the course of DOE's ongoing Section 106 (of the NHPA) consultation, the SHPO commented on DOE's preliminary definition of the APE and acknowledged that DOE had initiated consultation with the SHPO (see discussion under “Consultation with Others”, earlier in this document). The federal Environmental Protection Agency summarized the DOE's consultation responsibilities with Indian tribes and the SHPO in a letter dated July 26, 2012 (Vitulano 2012:9–10). The DOE's consultations with Indian tribes and the SHPO are documented in the subsections, “Department of Energy Consultations” and “Consultation with Others”.

CONCLUSIONS AND RECOMMENDATIONS

This cultural resources analysis is presently unable to definitively conclude that the proposed project would have no significant impact on known, CRHR/NRHP-eligible archaeological, ethnographic, or built-environment resources. URS (2012a) provides recommendations for mitigation in their archaeological reconnaissance report. Some of these measures include:

- Hiring a qualified professional archaeologist who will be responsible for the implementation of mitigation measures;
- Site avoidance as a post-certification mitigation strategy;
- Testing as a post-certification mitigation strategy;
- Conducting data recovery if a resource cannot be avoided;

- Having a qualified archaeologist monitor all ground-disturbing project activities and train project personnel on-site regarding the importance of archaeological resources and the legal basis for their protection;
- Having archaeological monitors keep daily field logs, with photographs as appropriate;
- Giving archaeological monitors the authority to halt construction in the vicinity of a discovery;
- Having a qualified archaeologist examine and recommend whether a discovery is potentially significant [CRHR-eligible];
- Submitting written monthly reports on monitoring to the Energy Commission; and
- Notifying the Kern County Coroner, the Energy Commission, and the project owner if human remains are discovered, and notifying the NAHC if the coroner determines the remains are Native American.

UNRESOLVED AREAS RELATING TO CULTURAL RESOURCES

Staff believes the HECA and related OEHI components would result in direct and indirect impacts to NRHP/CRHR-eligible cultural resources. However, staff requires additional information about cultural resources in order to complete its analysis. Without this information, staff cannot make a determination whether project impacts to sensitive cultural resources would be reduced to less than significant levels.

Staff will continue to work with the applicant, OEHI, and the DOE to resolve all outstanding information needs prior to the FSA/FEIS. Additional conditions of certification or modifications to currently proposed conditions of certification are likely to be necessary based on further consultation with agency personnel and information provided by the applicant. In summary, staff requires the following information in order to prepare and complete a FSA/FEIS:

- For the EOR components: all of the information required for cultural resources in the Energy Commission Siting Regulations, Appendix B (20 Cal. Code Regs., §1704(b)(2), App. B).
- Complete pedestrian survey results for all of HECA's linear alignments.
- Results of test excavations and evaluations of CRHR/NRHP eligibility for all archaeological sites that staff has identified as having the potential to be directly impacted by HECA or OEHI.
- Results of geoarchaeological field sampling.

These four categories of information need are discussed in detail below. In addition to these considerable data gaps, staff also needs to determine the function of the unidentified canal on MR 8, Adohr/Palms Farm.

Cultural Resources Data for Enhanced Oil Recovery Components

OEHI personnel informed staff in January 2013 that their environmental consultant, Stantec Corporation, completed a cultural resources inventory and report on the EOR components of the proposed project. Staff has yet to receive the cultural resources inventory report and records search materials, however. From conversations with OEHI, staff understands that the records search materials fill at least one paper-ream box, indicating that there is much information to review in concert with the inventory report. In order to have adequate time to review the cultural resources inventory report and records search materials—and meet the presiding committee's scheduling order—staff requests that the applicant provide this documentation to staff 8 weeks prior to the filing date for the FSA/FEIS. Assuming that the inventory report and records search materials adequately answer outstanding data requests concerning cultural resources in the proposed EOR components, staff would be able to incorporate the new information into and analyze it in the FSA/FEIS by the current filing date of July 15, 2013. Outstanding data requests concerning cultural resources in the proposed EOR components include A141–146, A189, and A190.

Complete Pedestrian Survey Results for Project Linears

The applicant has not completed pedestrian cultural resource survey of the proposed HECA linears outside of the EOR components. Specifically, portions of the proposed natural gas pipeline/railroad spur alignment and buffer area surrounding the controlled area have not been surveyed for cultural resources. Staff addressed the issue of survey completion along the proposed project linears and buffer areas in Data Requests A139–A140. Staff requires survey of these areas and adequate reporting on the surveys to incorporate into its analysis in the FSA/FEIS. In order to review the resulting survey report(s) and supplement its analysis within timeframe specified in the presiding committee's scheduling order, staff requests that the applicant provide the report to staff 6 weeks prior to the filing date for the FSA/FEIS. Assuming that the inventory report(s) are adequate to staff's information needs, staff would be able to incorporate the new information into and analyze it in the FSA/FEIS by the current filing date of July 15, 2013.

Significance Evaluations of Identified Archaeological Resources

Staff has identified 13 archaeological resources in the PAA/APE that require significance evaluations in order for staff to analyze the proposed project's impacts on cultural resources. Staff has reviewed the applicant's *Responses to CEC Data Requests – Set Three (45-Day Extension)* (January 16, 2013) to Data Requests A192–A194 (November 2, 2012) for the proposed project. Data Request A192 asked the applicant to prepare a subsurface testing plan for archaeological resources that the project would not avoid. Data Requests A193 and A194 ask for the approved plan to be implemented and for a report of the results to be submitted for review and approval. Staff differs with the applicant over whether the subject archaeological resources can be avoided through project modifications and has reiterated the need for the applicant to provide the information requested in Data Requests A192–A194. Without significance evaluations of these 13 archaeological resources, staff is unable to determine whether they constitute historical resources, unique archaeological resources, or historic properties, as defined in CEQA and Section 106 of the NHPA. In order to complete its cultural resources analysis in the FSA/FEIS by the current filing date of July 15, 2013, staff requests that the applicant satisfy all of the stipulations contained in Data Requests A192–A194 no later than 6 weeks prior to the scheduled FSA/FEIS filing date. Accordingly, the applicant is advised to submit the archaeological research design no later than 8 weeks prior to July 15 for staff review and approval. The archaeological resources subject to Data Requests A192–A194 are:

- KRM-IF-006/P-15-89
- BS-IF-003/P-15-2485
- P-15-7176/P-15-6725
- P-15-171
- P-15-179/KRM-IF-003/KRM-IF-004/KRM-IF-005
- P-15-3108
- HECA-2008-1
- HECA-2009-2
- HECA-2009-9
- HECA-2009-10
- HECA-2010-1
- HECA-2010-2[44]
- BS-IF-004

Geoarchaeological Investigation

The proposed project is located predominantly on landforms that have been subject to the accumulation of sediments[45] over the last 12,000 years, a context that increases the likelihood that older land surfaces are buried under the current ground surface and that archaeological resources were left and preserved on now-buried landforms. Assessing the potential for a proposed project to encounter and damage buried archaeological resources in depositional environments is an important component of cultural resources impact analysis, which in turn determines the character of a project's mitigation and monitoring program. The applicant completed an initial assessment of buried archaeological resources sensitivity for the proposed project as well as a research design for collecting and analyzing the data that staff needs to determine the proposed project's likelihood of damaging buried archaeological resources. Staff is presently reviewing the latter document. Once staff approves the research design, the applicant is responsible to implement it, excavating trenches to document, describe, and interpret subsurface geologic and soil conditions in the project area; taking and submitting samples for radiocarbon dating and other analyses; and reporting on their methods and conclusions. In order to have adequate time to review the resulting geoarchaeological report and supplement its analysis by the July 15, 2013 filing date, staff requests that the applicant provide the report to staff 6 weeks prior to the filing date for the FSA/FEIS.

[44] See Data Requests A69–A71.

[45] Earth scientists and archaeologists often refer to such contexts as "depositional landforms" or "depositional environments".

PROPOSED CONDITIONS OF CERTIFICATION

Staff has not received all of the information necessary to design mitigation measures for the proposed project. What staff presents here is a series of standard measures that would mitigate some, but not all, of the potential impacts of the project to cultural resources. Although staff concurs with many of the applicant's suggested mitigation measures, staff has added additional recommendations or expanded upon the applicant's suggestions to ensure that all impacts to cultural resources are mitigated to below the level of significance. The applicant's suggested mitigation measures and staff's additional recommendations are incorporated into the proposed Conditions **CUL-1** through **CUL-8**, below, intended to provide for the contingency of discovering archaeological resources during HECA construction and related activities. Staff's proposed **CUL-1** requires a Cultural Resources Specialist (CRS) to be retained and available during HECA construction-related excavations to evaluate any discovered buried resources and, if necessary, to conduct data recovery as mitigation for the project's unavoidable impacts on them. **CUL-2** requires the project owner to provide the CRS with all relevant cultural resources information and maps. **CUL-3** requires the CRS to write and submit to the Energy Commission compliance project manager (CPM) a Cultural Resources Mitigation and Monitoring Plan (CRMMP). **CUL-4** requires the CRS to write and submit to the CPM a final report on all HECA cultural resources monitoring and mitigation activities. **CUL-5** requires the project owner to train workers to recognize cultural resources and instruct them to halt construction if cultural resources are discovered. **CUL-6** prescribes the monitoring, by an archaeologist and, possibly, by a Native American, intended to identify buried archaeological deposits. **CUL-7** requires the project owner to halt ground-disturbing activities in the area of an archaeological discovery and to fund data recovery, if the discovery is evaluated as NRHP/CRHR-eligible. **CUL-8** would cover the possibility that the proposed project would need to make use of a soil borrow site that had not been surveyed for cultural resources in the past five years.

Additional conditions of certification will be developed when all of the required cultural resources information is received.

Staff would likely recommend a suite of mitigation measures similar to the conditions presented below for the proposed EOR components of HECA. Staff believes, however, that it is premature to formally make such recommendations, as very little information was available to staff concerning cultural resources in the EOR portion of the PAA/APE. Upon receipt of the cultural resources inventory report and supporting documentation for the proposed EOR facilities, staff will analyze the potential project impacts and present conclusions and proposed mitigation measures in the FSA/FEIS.

PROPOSED CONDITIONS OF CERTIFICATION

CUL-1 Prior to the start of ground disturbance (as defined in the General Conditions section); post-certification cultural resources activities (including but not limited to "survey", "in-field data recording," "surface collection," "testing," "data recovery" or "geoarchaeology"); surface grading or subsurface soil work during pre-construction activities or site mobilization; or mowing activities and heavy equipment use in loose or sandy soils, at the site and for access roads and linear facilities, the project owner shall obtain the services of a Cultural Resources Specialist (CRS) and one or more alternate CRS. The project owner shall submit the resumes and qualifications for the CRS, CRS alternates, and all technical specialists to the CPM for review and approval.

The CRS shall manage all cultural resources monitoring, mitigation, curation, and reporting activities, and any post-certification cultural resources activities (as defined in the previous paragraph), unless management of these is otherwise provided for in accordance with the cultural resources conditions of certification (Conditions). The CRS shall serve as the primary point of contact on all cultural resources matters for the Energy Commission. The CRS may elect to obtain the services of Cultural Resources Monitors (CRMs), Native American Monitors (NAMs), and other technical specialists, if needed, to assist in monitoring, mitigation, and curation activities. The project owner shall ensure that the CRS makes recommendations regarding the eligibility for listing in the NRHP/CRHR of any cultural resources that are newly discovered or that may be affected in an unanticipated manner.

No construction-related ground disturbance or grading, boring, and trenching, as defined in the General Conditions for this project; post-certification cultural resources activities (as defined in the first paragraph of this condition); surface grading or subsurface soil work during pre-construction activities or site mobilization; or mowing activities and heavy equipment use in loose or sandy soils, at the site, access roads, and linear facilities, shall occur prior to CPM approval of the CRS and alternates, unless such activities are specifically approved by the CPM.

Approval of a CRS may be denied or revoked for reasons including but not limited to non-compliance on this or other Energy Commission projects and for concurrent service as CRS on an unmanageable number of Energy Commission projects, as determined by the CPM. After all ground disturbance is completed and the CRS has fulfilled all responsibilities specified in these cultural resources conditions, the project owner may discharge the CRS, after receiving approval from the CPM.

If, during operation of the proposed power plant, circumstances develop that would require ground disturbance in soils or sediments previously undisturbed during project construction, no surface grading or subsurface soil work shall occur prior to submission of a Petition to Modify and CPM review and approval of project-specific protocol for addressing unanticipated discoveries, consistent with the approved CRMMP.

CULTURAL RESOURCES SPECIALIST

The resumes for the CRS and alternate CRS(s) shall include information demonstrating to the satisfaction of the CPM that their training and backgrounds conform to the U.S. Secretary of the Interior’s Professional Qualifications Standards, as published in 36 C.F.R., part 61. In addition, the CRS and alternate CRS(s) shall have the following qualifications:

1. Qualifications appropriate to the needs of the project, including a background in anthropology, archaeology, history, architectural history, or a related field;

2. At least 10 years of archaeological or historical experience (as appropriate considering the nature of predominant cultural resources on the project site), with resources mitigation and fieldwork;

3. At least one year of field experience in California; and

4. At least three years of experience in a decision-making capacity on cultural resources projects in California and the appropriate training and experience to knowledgably make recommendations regarding the significance of cultural resources. The resumes of the CRS and alternate CRS shall include the names and telephone numbers of contacts familiar with the work of the CRS/alternate CRS on referenced projects and demonstrate to the satisfaction of the CPM that the CRS/alternate CRS has the appropriate training and experience to implement effectively the Conditions.

CULTURAL RESOURCES MONITORS

CRMs shall have the following qualifications:

1. B.S. or B.A. degree in anthropology, archaeology, historical archaeology, or a related field; and one year of archaeological field experience in California; or

2. A.S. or A.A. degree in anthropology, archaeology, historical archaeology, or a related field, and four years of archaeological field experience in California; or

3. Enrollment in upper division classes pursuing a degree in the fields of anthropology, archaeology, historical archaeology, or a related field, and two years of archaeological field experience in California.

NATIVE AMERICAN MONITORS

The project owner shall ensure that the CRS obtains the services of qualified NAMs. Preference in selecting NAMs shall be given to Native Americans with:

1. traditional ties to the area that shall be monitored, and

2. the highest qualifications as described by the Native American Heritage Commission (NAHC) document entitled: *Guidelines for Monitors/Consultants Native American Cultural, Religious, and Burial Sites* (NAHC 2005).

CULTURAL RESOURCES TECHNICAL SPECIALISTS

The resume(s) of any additional technical specialist(s), e.g., geoarchaeologist, historical archaeologist, historian, architectural historian, and/or physical anthropologist, shall be submitted to the CPM for approval.

The resume of each proposed specialist shall demonstrate that their training and background meet the U.S. Secretary of Interior's Professional Qualifications Standards for their specialty (if appropriate), as published in 36 C.F.R., part 61, and show the completion of appropriate graduate-level coursework. The resumes of specialists shall include the names and telephone numbers of contacts familiar with the work of these persons on projects referenced in the resumes and demonstrate to the satisfaction of the CPM that these persons have the appropriate training and experience to undertake the required research. The project owner may name and hire any specialist prior to certification. All specialists are under the supervision of the CRS.

Verification:

1. At least 45 days prior to the start of construction-related ground disturbance, the project owner shall submit the resume for the CRS and alternate CRS(s) (if proposed), to the CPM for review and approval.

2. At least 10 days prior to a termination or release of the CRS, or within 10 days after the resignation of a CRS, the project owner shall submit the resume of the proposed new CRS to the CPM for review and approval. At the same time, the project owner shall also provide to the proposed new CRS the same documents given to the previous CRS, plus all cultural resources documents, field notes, photographs, and other cultural resources materials generated during the compliance phase of the project to that date. If there is no alternate CRS in place to conduct the duties of the CRS, a previously approved CRM may serve in place of a CRS so that construction-related ground disturbance may continue up to a maximum of three days without a CRS. If cultural resources are discovered, construction-related ground disturbance will remain halted until there is a CRS or alternate CRS to make a recommendation regarding significance.

3. At least 20 days prior to construction-related ground disturbance, the CRS shall provide a letter naming anticipated CRMs, NAMs, and additional specialists, for the project. The letter shall state that the identified monitors and specialists meet the minimum qualifications for cultural resources monitoring and resource management required by this Condition.

4. If efforts to obtain the services of a qualified NAM are unsuccessful, the project owner shall inform the CPM of this situation in writing at least 30 days prior to the beginning of post-certification cultural resources field work or construction related ground disturbance.

5. At least 5 days prior to additional CRMs or NAMs beginning on-site duties during the project, the CRS shall provide for the CRS's review and approval additional letters to the CPM identifying the monitors and attesting to their qualifications.

6. At least 10 days prior to any technical specialists beginning tasks, the resume(s) of the specialists shall be provided to the CPM for review and approval.

7. At least 10 days prior to the start of construction-related ground disturbance, the project owner shall confirm in writing to the CPM that the approved CRS will be available for onsite work and is prepared to implement the cultural resources conditions.

CUL-2 Prior to the start of construction-related ground disturbance or grading, boring, and trenching, as defined in the General Conditions for this project; or surface grading or subsurface soil work during pre-construction activities or site mobilization; or mowing activities and heavy equipment use in loose or sandy soils, at the project site, access roads, and linear facilities, if the CRS has not previously worked on the project, the project owner shall provide the CRS with copies of the AFC, data responses, confidential cultural resources reports, all supplements, the Energy Commission staff's cultural resources FSA/FEIS, and the cultural resources conditions of certification from the Final Decision for the project. The project owner shall also provide the CRS and the CPM with maps and drawings showing the footprints of the power plant, all linear facility routes, all access roads, and all laydown areas. Maps shall include the appropriate USGS quadrangles and a map at an appropriate scale (e.g., 1:24,000 and 1 inch = 200 feet, respectively) for plotting cultural features or materials. If the CRS requests enlargements or strip maps for linear facility routes, the project owner shall provide copies to the CRS and CPM. The CPM shall review map submittals and, in consultation with the CRS, approve those that are appropriate for use in cultural resources planning activities. No ground disturbance shall occur prior to CPM approval of maps and drawings, unless such activities are specifically approved by the CPM.

Maps shall include the NRHP/CRHR-eligible historic built environment resources identified in the FSA/FEIS. Maps shall indicate how horizontal directional drilling crossings under the California Aqueduct comply with the best practices set forth in CDWR California Encroachment Permit Guidelines, June 2005.

If construction of the project would proceed in phases, maps and drawings not previously provided shall be provided to the CRS and CPM prior to the start of each phase. Written notice identifying the proposed schedule of each project phase shall be provided to the CRS and CPM.

Weekly, until ground disturbance is completed, the project construction manager shall provide to the CRS and CPM a schedule of project activities for the following week, including the identification of area(s) where ground disturbance will occur during that week.

The project owner shall notify the CRS and CPM of any changes to the scheduling of the construction phases.

Verification:

1. At least 40 days prior to the start of ground disturbance, the project owner shall provide the CPM notice that the AFC, data responses, confidential cultural resources documents, all supplements, FSA/FEIS, and Final Commission Decision have been provided to the CRS, if needed, and the subject maps and drawings to the CRS and CPM. The CPM will review submittals in consultation with the CRS and approve maps and drawings suitable for cultural resources planning activities.

2. At least 15 days prior to the start of ground disturbance, if there are changes to any project-related footprint, the project owner shall provide revised maps and drawings for the changes to the CRS and CPM.

3. At least 15 days prior to the start of each phase of a phased project, the project owner shall submit the appropriate maps and drawings, if not previously provided, to the CRS and CPM.

4. Weekly, during ground disturbance, a schedule of the next week's anticipated project activity shall be provided to the CRS and CPM by letter, e-mail, or fax.

5. Monthly, during ground disturbance, email progress report to the CPM, interested Native Americans and other interested parties.

6. Within 5 days of changing the scheduling of phases of a phased project, the project owner shall provide written notice of the changes to the CRS and CPM.

CUL-3 Prior to the start of construction-related ground disturbance or grading, boring, and trenching, as defined in the General Conditions for this project; or surface grading or subsurface soil work during pre-construction activities or site mobilization; or mowing activities and heavy equipment use in loose or sandy soils, at the project site, access roads, and linear facilities, the project owner shall submit the Cultural Resources Mitigation and Monitoring Plan (CRMMP), as prepared by or under the direction of the CRS, to the CPM for review and approval. The CRMMP shall follow the content and organization of the draft model CRMMP, provided by the CPM, and the authors' name(s) shall appear on the title page of the CRMMP. The CRMMP shall identify measures to minimize potential impacts to sensitive cultural resources. Implementation of the CRMMP shall be the responsibility of the CRS and the project owner. Copies of the CRMMP shall reside with the CRS, alternate CRS, each CRM, and the project owner's on-site construction manager. No ground disturbance shall occur prior to CPM approval of the CRMMP, unless such activities are specifically approved by the CPM. The CRMMP shall be designated as a confidential document if the location(s) of cultural resources are described or mapped.

The CRMMP shall include, but not be limited to, the following elements and measures:

1. The following statement included in the Introduction: “Any discussion, summary, or paraphrasing of the conditions of certification in this CRMMP is intended as general guidance and as an aid to the user in understanding the conditions and their implementation. The Conditions, as written in the Commission Decision, shall supersede any summarization, description, or interpretation of the conditions in the CRMMP. The Cultural Resources conditions of certification from the Commission Decision are contained in Appendix A.”

2. A proposed general research design that includes a discussion of archaeological research questions and testable hypotheses specifically applicable to the project area, and a discussion of artifact collection, retention/disposal, and curation policies as related to the research questions formulated in the research design. The research design shall specify that the preferred treatment strategy for any buried archaeological deposits is avoidance. A specific mitigation plan shall be prepared for any unavoidable impacts to any CRHR/NRHP-eligible (as determined by the CPM) resources. A prescriptive treatment plan may be included in the CRMMP for limited data types.

3. Specification of the implementation sequence and the estimated time frames needed to accomplish all project-related tasks during the ground-disturbance and post-ground–disturbance analysis phases of the project.

4. Identification of the person(s) expected to perform each of the tasks, their responsibilities, and the reporting relationships between project construction management and the mitigation and monitoring team.

5. A description of the manner in which Native American observers or monitors will be included, the procedures to be used to select them, and their role and responsibilities.

6. A description of all impact-avoidance measures (such as flagging or fencing) to prohibit or otherwise restrict access to sensitive resource areas that are to be avoided during ground disturbance, construction, and/or operation, and identification of areas where these measures are to be implemented. The description shall address how these measures would be implemented prior to the start of ground disturbance and how long they would be needed to protect the resources from project-related effects.

7. A statement that all encountered cultural resources over 50 years old shall be recorded on DPR 523 forms and mapped and photographed. In addition, all archaeological materials retained as a result of the archaeological investigations (survey, testing, data recovery) shall be curated in accordance with the California State Historical Resources Commission’s (SHRC) *Guidelines for the Curation of Archaeological*

Collections (SHRC 1993), into a retrievable storage collection in a public repository or museum.

8. A statement that the project owner will pay all curation fees for artifacts recovered and for related documentation produced during cultural resources investigations conducted for the project. The project owner shall identify three possible curation facilities that could accept cultural resources materials resulting from project activities.

9. A statement demonstrating when and how the project owner will comply with Health and Human Safety Code, section 7050.5(b) and Public Resources Code, section 5097.98(b) and (e), including the statement that the project owner will notify the CPM and the NAHC of the discovery of human remains.

10. A statement that the CRS has access to equipment and supplies necessary for site mapping, photography, and recovery of any cultural resource materials that are encountered during ground disturbance and cannot be treated prescriptively.

11. A description of the contents, format, and review and approval process of the final Cultural Resource Report (CRR), which shall be prepared according to *Archaeological Resource Management Report* (ARMR) guidelines.

<u>Verification:</u>

1. Upon approval of the CRS proposed by the project owner, the CPM will provide to the project owner an electronic copy of the draft model CRMMP for the CRS.

2. At least 30 days prior to the start of ground disturbance, the project owner shall submit the CRMMP to the CPM for review and approval.

3. At least 30 days prior to the start of ground disturbance, in a letter to the CPM, the project owner shall agree to pay curation fees for any materials generated or collected as a result of the archaeological investigations (survey, testing, and data recovery).

4. Within 90 days after completion of ground disturbance (including landscaping), if cultural materials requiring curation were generated or collected, the project owner shall provide to the CPM a copy of an agreement with, or other written commitment from, a curation facility that meets the standards stated in SHRC (1993), to accept the cultural materials from this project. Any agreements concerning curation will be retained and available for audit for the life of the project.

CUL-4 The project owner shall submit the final CRR to the CPM for approval. The final CRR shall be written by, or under the direction of, the CRS and shall be provided in the ARMR format. The final CRR shall report on all field activities including dates, times and locations, results, samplings, and analyses. The final CRR shall be a confidential document if it describes or maps the location(s) of cultural resources. All survey reports, DPR 523 forms, data recovery reports, and any additional research reports not previously submitted to the CHRIS and the SHPO shall be included as appendices to the final CRR.

If the project owner requests a suspension of ground disturbance and/or construction activities, then a draft CRR that covers all cultural resources activities associated with the project shall be prepared by the CRS and submitted to the CPM for review and approval on the same day as the suspension/extension request. The draft CRR shall be retained at the project site in a secure facility until ground disturbance and/or construction resumes or the project is withdrawn. If the project is withdrawn, then a final CRR shall be submitted to the CPM for review and approval at the same time as the withdrawal request.

Verification:

1. Within 30 days after requesting a suspension of construction activities, the project owner shall submit a draft CRR to the CPM for review and approval.

2. Within 90 days after completion of ground disturbance (including landscaping), the project owner shall submit the final CRR to the CPM for review and approval. If any reports have previously been sent to the CHRIS, then receipt letters from the CHRIS or other verification of receipt shall be included in an appendix.

3. Within 10 days after CPM approval of the CRR, the project owner shall provide documentation to the CPM confirming that copies of the final CRR have been provided to the SHPO, the CHRIS, the curating institution, if archaeological materials were collected, and to the tribal chairpersons of any Native American groups requesting copies of project-related reports.

CUL-5 Prior to and for the duration of construction-related ground disturbance or grading, boring, and trenching, as defined in the General Conditions for this project; or surface grading or subsurface soil work during pre-construction activities or site mobilization; or mowing activities and heavy equipment use in loose or sandy soils, at the project site, access roads, and linear facilities, the project owner shall provide Worker Environmental Awareness Program (WEAP) training to all new workers within their first week of employment at the project site, along the linear facilities routes, and at laydown areas, roads, and other ancillary areas. The cultural resources part of this training shall be prepared by the CRS, may be conducted by any member of the archaeological team, and may be presented in the form of a video. The CRS is encouraged to include a Native American presenter in the training to contribute the Native American perspective on archaeological and ethnographic resources. During the training and during construction, the CRS shall be available (by telephone or in person) to answer questions posed by employees. The training may be discontinued when ground disturbance is completed or suspended, but must be resumed when ground disturbance, such as landscaping, resumes.

The training shall include:

1. A discussion of applicable laws and penalties under law;

2. Samples or visuals of artifacts that might be found in the project vicinity;

3. A discussion of what such artifacts may look like when partially buried, or wholly buried and then freshly exposed;

4. A discussion of what prehistoric and historical archaeological deposits look like at the surface and when exposed during construction, and the range of variation in the appearance of such deposits;

5. Instruction that the CRS, alternate CRS, and CRMs have the authority to halt ground disturbance in the area of a discovery to an extent sufficient to ensure that the resource is protected from further impacts, as determined by the CRS;

6. Instruction that employees, if the CRS, alternate CRS, or CRMs are not present, are to halt work on their own in the vicinity of a potential cultural resources discovery, and shall contact their supervisor and the CRS or CRM, and that redirection of work would be determined by the construction supervisor and the CRS;

7. An informational brochure that identifies reporting procedures in the event of a discovery;

8. An acknowledgement form signed by each worker indicating that they have received the training; and

9. A sticker that shall be placed on hard hats indicating that environmental training has been completed.

No ground disturbance shall occur prior to implementation of the WEAP program, unless such activities are specifically approved by the CPM.

Verification:

1. At least 30 days prior to the beginning of ground disturbance, the CRS shall provide the cultural resources WEAP training program draft text, including Native American participation, and graphics and the informational brochure to the CPM for review and approval.

2. At least 15 days prior to the beginning of ground disturbance, the CPM will provide to the project owner a WEAP Training Acknowledgement form for each WEAP-trained worker to sign.

3. Monthly, until ground disturbance is completed, the project owner shall provide in the Monthly Compliance Report (MCR) the WEAP Training Acknowledgement forms of workers who have completed the training in the prior month and a running total of all persons who have completed training to date.

CUL-6 Prior to the start of construction-related ground disturbance or grading, boring, and trenching, as defined in the General Conditions for this project; or surface grading or subsurface soil work during pre-construction activities or site mobilization; or mowing activities and heavy equipment use in loose or sandy soils, at the project site, access roads, and linear facilities, the project owner shall notify the CPM and all interested Native Americans of the date on which ground disturbance will ensue. The project owner shall ensure that the CRS, alternate CRS, or CRMs monitor full time all of the above specified ground disturbance at the project site, along the linear facilities routes, and at laydown areas, roads, and other ancillary areas, to ensure there are no impacts to undiscovered cultural resources and to ensure that known cultural resources are not affected in an unanticipated manner.

Full-time archaeological monitoring for this project shall be the archaeological monitoring of the ground-disturbing activities specified in the previous paragraph, for as long as the activities are ongoing. Where excavation equipment is actively removing dirt and hauling the excavated material farther than 50 feet from the location of active excavation, full-time archaeological monitoring shall require at least two monitors per excavation area. In this circumstance, one monitor shall observe the location of active excavation and a second monitor shall inspect the dumped material. For excavation areas where the excavated material is dumped no farther than 50 feet from the location of active excavation, one monitor shall both observe the location of active excavation and inspect the dumped material.

In the event that the CRS believes that the required number of monitors is not appropriate in certain locations, a letter or e-mail detailing the justification for changing the number of monitors shall be provided to the CPM for review and approval prior to any change in the number of monitors.

The project owner shall obtain the services of one or more NAMs to monitor construction-related ground disturbance in areas where Native American artifacts may be discovered. Contact lists of interested Native Americans and guidelines for monitoring shall be obtained from the NAHC. Preference in selecting an NAM shall be given to Native Americans with traditional ties to the area that shall be monitored. If efforts to obtain the services of a qualified NAM are unsuccessful, the project owner shall immediately inform the CPM. The CPM will either identify potential monitors or will allow construction-related ground disturbance to proceed without an NAM.

The research design in the CRMMP shall govern the collection, treatment, retention/disposal, and curation of any archaeological materials encountered. On forms provided by the CPM, CRMs shall keep a daily log of any monitoring and other cultural resources activities and any instances of non-compliance with the Conditions and/or applicable LORS. The daily monitoring logs shall at a minimum include the following:

- First and last name of the CRM and any accompanying NAM.
- Time in and out.
- Weather. Specify if weather conditions led to work stoppages.

- Work location (project component). Provide specifics—.e.g., transmission ROW, solar unit A, power block.
- Proximity to site location. Specify if work conducted within 1000 feet of a known cultural resource.
- Work type (machine).
- Work crew (company, operator, foreman).
- Depth of excavation.
- Description of work.
- Stratigraphy.
- Artifacts, listed with the following identifying features:
  - Field artifact #: When recording artifacts in the daily monitoring logs, the CRS shall institute a field numbering system to reduce the likelihood of repeat artifact numbers. A typical numbering system could include a project abbreviation, monitor's initials, and a set of numbers given to that monitor: e.g., HECA-MB-123.
  - Description.
  - Measurements.
  - UTM.
- Whether artifacts are likely to be isolates or components of larger resources.
- Assessment of significance of any finds.
- Actions taken.
- Plan for the next work day.

A cover sheet shall be submitted with each day's monitoring logs, and shall at a minimum include the following:

- Count and list of first and last names of all CRMs and of all NAMs for that day.
- General description (in paragraph form) of that day's overall monitoring efforts, including monitor names and locations.
- Any reasons for halting work that day.
- Count and list of all artifacts found that day: include artifact #, location (i.e., grading in Unit X), measurements, UTMs, and very brief description (i.e., historic can, granitic biface, quartzite flake).
- Whether any artifacts were found out of context (i.e., in fill, caisson drilling, flood debris, spoils pile).

Copies of the daily monitoring logs and cover sheets shall be provided by email from the CRS to the CPM, as follows:

- Each day’s monitoring logs and cover sheet shall be merged into one PDF document
- The PDF title and headings, and emails shall clearly indicate the date of the applicable monitoring logs.
- PDFs for any revised or resubmitted versions shall use the word “revised” in the title.

Daily and/or weekly maps shall be submitted along with the monitoring logs as follows:

- The CRS shall provide daily and/or weekly maps of artifacts at the request of the CPM. A map shall also be provided if artifact locations show complexity, high density, or other unique considerations.
- Maps shall include labeled artifacts, project boundaries, previously recorded sites and isolates, aerial imagery background, and appropriate scales.

From the daily monitoring logs, the CRS shall compile a monthly monitoring summary report to be included in the MCR. If there are no monitoring activities, the summary report shall specify why monitoring has been suspended.

- The Cultural Resources section of the MCR shall be prepared in coordination with the CRS, and shall include a monthly summary report of cultural resources-related monitoring. The summary shall:
  - List the number of CRMs and NAMs on a daily basis, as well as provide monthly monitoring-day totals.
  - Give an overview of cultural resource monitoring work for that month, and discuss any issues that arose.
  - Describe fulfillment of requirements of each cultural mitigation measure.
  - Summarize the confidential appendix to the MCR, without disclosing any specific confidential details.
  - Include the artifact concordance table (as discussed under the next bullet point), but with removal of UTMs.
- Each MCR, prepared under supervision of the CRS, shall be accompanied by a confidential appendix that contains completed DPR 523A forms for all artifacts recorded or collected in that month. For any artifact without a corresponding DPR form, the CRS shall specify why the DPR form is not applicable or pending (i.e. as part of a larger site update).
  - A concordance table that matches field artifact numbers with the artifact numbers used in the DPR forms shall be included. The sortable table shall contain each artifact’s date of collection and UTM numbers, and note if an artifact has been deaccessioned or otherwise does not

have a corresponding DPR form. Any post-field log recordation changes to artifact numbers shall also be noted.

- DPR forms shall be submitted as one combined PDF.
  - The PDF shall organize DPR forms by site and/or artifact number.
  - The PDF shall include an index and bookmarks.
- If artifacts from a given site location (in close proximity of each other or an existing site) are collected month after month, and if agreed upon with the CPM, a final updated DPR for the site may be submitted at the completion of monitoring. The monthly concordance table shall note that the DPR form for the included artifacts is pending.

The CRS or alternate CRS shall report daily to the CPM on the status of the project's cultural resources-related activities, unless reducing or ending daily reporting is requested by the CRS and approved by the CPM.

In the event that the CRS believes that the current level of monitoring is not appropriate in certain locations, a letter or e-mail detailing the justification for changing the level of monitoring shall be provided to the CPM for review and approval prior to any change in the level of monitoring.

The CRS, at his or her discretion, or at the request of the CPM, may informally discuss cultural resources monitoring and mitigation activities with Energy Commission technical staff.

Cultural resources monitoring activities are the responsibility of the CRS. Any interference with monitoring activities, removal of a monitor from duties assigned by the CRS, or direction to a monitor to relocate monitoring activities by anyone other than the CRS shall be considered non-compliance with these Conditions.

Upon becoming aware of any incidents of non-compliance with the Conditions and/or applicable LORS, the CRS and/or the project owner shall notify the CPM. The CRS shall also recommend corrective action to resolve the problem or achieve compliance with the Conditions. When the issue is resolved, the CRS shall write a report describing the issue, the resolution of the issue, and the effectiveness of the resolution measures. This report shall be provided in the next MCR for the review of the CPM.

Verification:

1. At least 30 days prior to the start of ground disturbance, the CPM will notify all Native Americans with whom Energy Commission staff communicated during the project review of the date on which the project's ground disturbance will begin.
2. At least 30 days prior to the start of ground disturbance, the CPM will provide to the CRS an electronic copy of a form to be used as a daily monitoring log and information to be included in the cover sheet for the daily monitoring logs.
3. While monitoring is on-going, the project owner shall submit each day's monitoring logs and cover sheet merged into one PDF document by email within 24 hours.

4. The CRS and/or project owner shall notify the CPM of any incidents of non-compliance with the Conditions and/or applicable LORS by telephone or email within 24 hours
5. The CRS shall provide daily maps of artifacts along with the daily monitoring logs if more than 10 artifacts are found per day, or as requested by the CPM.
6. The CRS shall provide weekly maps of artifacts if there more than 50 artifacts are found per week, or as requested by the CPM. The map shall be submitted within two business days after the end of each week.
7. Within 15 days of receiving from a local Native American group a request that a NAM be employed, the project owner shall submit a copy of the request and a copy of a response letter to the group notifying them that a NAM has been employed and identifying the NAM.
8. Monthly, while monitoring is on-going, the project owner shall submit MCRs and accompanying monthly summary reports. The project owner shall attach any new DPR 523A forms, under confidential cover, completed for finds treated prescriptively, as specified in the CRMMP.
    a. Final updated DPRs with sites (where artifacts are collected month after month) can be submitted at the completion of monitoring, as agreed upon with the CPM.
9. At least 24 hours prior to implementing a proposed change in monitoring level, the project owner shall submit to the CPM, for review and approval, a letter or e-mail (or some other form of communication acceptable to the CPM) detailing the CRS's justification for changing the monitoring level.
10. At least 24 hours prior to reducing or ending daily reporting, the project owner shall submit to the CPM, for review and approval, a letter or e-mail (or some other form of communication acceptable to the CPM) detailing the CRS's justification for reducing or ending daily reporting.
11. Within 15 days of receiving them, the project owner shall submit to the CPM copies of any comments or information provided by Native Americans in response to the project owner's transmittals of information.

CUL-7 The project owner shall grant authority to halt ground disturbance to the CRS, alternate CRS, and the CRMs in the event of a discovery. Redirection of ground disturbance shall be accomplished under the direction of the construction supervisor in consultation with the CRS.

In the event that a cultural resource over 50 years of age is found (or if younger, determined exceptionally significant by the CPM), or impacts to such a resource can be anticipated, ground disturbance shall be halted or redirected in the immediate vicinity of the discovery sufficient to ensure that the resource is protected from further impacts. If the discovery includes human remains, the project owner shall comply with the requirements of Health and Human Safety Code, section 7050.5(b) and notify the CPM and the NAHC of the discovery of human remains. No action with respect to the disposition of human remains of Native American origin shall be initiated without direction from the CPM. Monitoring, including Native American monitoring, and daily reporting, as provided in other conditions, shall continue during the project's ground-disturbing activities elsewhere, while the halting or redirection of ground disturbance in the vicinity of the discovery shall remain in effect until the CRS has visited the discovery, and all of the following have occurred:

1. The CRS has notified the project owner, and the CPM has been notified within 24 hours of the discovery, or by Monday morning if the cultural resources discovery occurs between 8:00 AM on Friday and 8:00 AM on Sunday morning, and provided a description of the discovery (or changes in character or attributes), the action taken (i.e., work stoppage or redirection), a recommendation of CRHR/NRHP eligibility, and recommendations for data recovery from any cultural resources discoveries, whether or not a determination of CRHR/NRHP eligibility has been made.
2. If the discovery would be of interest to Native Americans, the CRS has notified all Native American groups that expressed a desire to be notified in the event of such a discovery.
3. The CRS has completed field notes, measurements, and photography for a DPR 523 "Primary Record" form. Unless the find can be treated prescriptively, as specified in the CRMMP, the "Description" entry of the DPR 523 "Primary Record" form shall include a recommendation on the CRHR/NRHP eligibility of the discovery. The project owner shall submit completed forms to the CPM.
4. The CRS, the project owner, and the CPM have conferred, and the CPM has concurred with the recommended eligibility of the discovery and approved the CRS's proposed data recovery, if any, including the curation of the artifacts, or other appropriate mitigation; and any necessary data recovery and mitigation have been completed.

Ground disturbance may resume only with the approval of the CPM.

<u>Verification:</u>

1. At least 30 days prior to the start of ground disturbance, the project owner shall provide the CPM and CRS with a letter confirming that the CRS, alternate CRS, and CRMs have the authority to halt ground disturbance in the vicinity of a cultural resources discovery, and that the project owner shall ensure that the CRS notifies the CPM within 24 hours of a discovery, or by Monday morning if the cultural resources discovery occurs between 8:00 AM on Friday and 8:00 AM on Sunday morning.
2. Unless the discovery can be treated prescriptively, as specified in the CRMMP, completed DPR 523 forms for resources newly discovered during ground disturbance shall be submitted to the CPM for review and approval no later than 24 hours following the notification of the CPM, or 48 hours following the completion of data recordation/recovery, whichever the CRS decides is more appropriate for the subject cultural resource.
3. Within 48 hours of the discovery of a resource of interest to Native Americans, the project owner shall ensure that the CRS notifies all Native American groups that

expressed a desire to be notified in the event of such a discovery, and the CRS must inform the CPM when the notifications are complete.

4. No later than 30 days following the discovery of any Native American cultural materials, the project owner shall submit to the CPM copies of the information transmittal letters sent to the chairpersons of the Native American tribes or groups who requested the information. Additionally, the project owner shall submit to the CPM copies of letters of transmittal for all subsequent responses to Native American requests for notification, consultation, and reports and records.
5. Within 15 days of receiving them, the project owner shall submit to the CPM copies of any comments or information provided by Native Americans in response to the project owner's transmittals of information.

CUL-8 If fill soils must be acquired from a non-commercial borrow site or disposed of to a non-commercial disposal site, unless less-than-five-year-old surveys of these sites for archaeological resources are provided to and approved by the CPM, the CRS shall survey the borrow or disposal site(s) for cultural resources and record on DPR 523 forms any that are identified. When the survey is completed, the CRS shall convey the results and recommendations for further action to the project owner and the CPM, who will determine what, if any, further action is required. If the CPM determines that significant archaeological resources that cannot be avoided are present at the borrow site, the project owner must either select another borrow or disposal site or implement **CUL-7** prior to any use of the site. The CRS shall report on the methods and results of these surveys in the final CRR.

<u>**Verification:**</u>

1. As soon as the project owner knows that a non-commercial borrow site and/or disposal site will be used, he/she shall notify the CRS and CPM and provide documentation of previous archaeological survey, if any, dating within the past five years, for CPM approval.
2. In the absence of documentation of recent archaeological survey, at least 30 days prior to any soil borrow or disposal activities on the non-commercial borrow and/or disposal sites, the CRS shall survey the site(s) for archaeological resources. The CRS shall notify the project owner and the CPM of the results of the cultural resources survey, with recommendations, if any, for further action.

CULTURAL RESOURCES ACRONYM GLOSSARY

ac	acre(s)
ACHP	Advisory Council on Historic Preservation
ADA	Americans with Disabilities Act
AFC	Application for Certification
amsl	above mean sea level
ARMR	Archaeological Resource Management Report
APE	area of potential effects
APN	Assessor parcel number
B.P.	Before present (A.D. 1950)
BVWSD	Buena Vista Water Storage District
CA	California
Caltrans	California Department of Transportation
CB	Construction Battalion
CCC	Civilian Conservation Corps
CCD	Census County Division
CCS	Cryptocrystalline silicate (rock)
CDP	Census Designated Place
CDWR	California Department of Water Resources
CEC	California Energy Commission
CEQ	Council on Environmental Quality
CEQA	California Environmental Quality Act
C.F.R.	Code of Federal Regulations
CHRIS	California Historical Resources Information System

Conditions	Conditions of Certification
CO_2	carbon dioxide
CPM	Compliance Project Manager
CRHR	California Register of Historical Resources
CRM	Cultural Resources Monitor
CRMP	Cultural Resources Management Plan
CRMMP	Cultural Resources Monitoring and Mitigation Plan
CRR	Cultural Resource Report
CRS	Cultural Resources Specialist
CSUB	California State University, Bakersfield
DOE	Department of Energy (United States)
DPR 523	Department of Parks and Recreation cultural resources recordation form
E	east
EHOF	Elk Hills Oil Field
EHPP	Elk Hills Power Project
EO	Executive Order
EOR	enhanced oil recovery
FCR	fire-cracked rock
FSA/FEIS	Final Staff Assessment/Final Environmental Impact Statement
ft	foot, feet
GLO	General Land Office
GPS	global positioning system
HDD	horizontal directional drilling
HECA	Hydrogen Energy California
I-5	Interstate 5

KE	Kern [county]
KER	Kern [county]
KIN	Kings [county]
KVWC	Kern Valley Water Company
KVWCC	Kern Valley Water Company Canal
LORS	laws, ordinances, regulations, and standards
LTS	less than significant
MCR	Monthly Compliance Report
MER	Merced [county]
mi	mile(s)
MLD	Most Likely Descendent
MR	Map Reference
NAHC	Native American Heritage Commission
NAM	Native American Monitor
NEPA	National Environmental Policy Act
NHPA	National Historic Preservation Act
NPR-1	Naval Petroleum Reserve No. 1
NRHP	National Register of Historic Places
OEHI	Occidental of Elk Hills, Inc.
OHP	Office of Historic Preservation
PA	Programmatic Agreement
PAA	Project Area of Analysis
PAA/APE	Project Area of Analysis/Area of Potential Effects
PG&E	Pacific Gas and Electric Company

PSA	Preliminary Staff Assessment
PSA/DEIS	Preliminary Staff Assessment/Draft Environmental Impact Statement
PVC	polyvinylchloride
R	range
ROW	right-of-way
S	south
SCE	Southern California Edison
SHPO	State Historic Preservation Officer
SHRC	State Historical Resources Commission
SR	State Route
SPRC	Southern Pacific Railroad Company
SSJVIC	Southern San Joaquin Valley Information Center
SSURGO	Soil Survey Geographic [database]
Staff	Energy Commission cultural resources technical staff
SWP	State Water Project
T	township
THPO	Tribal Historic Preservation Officer
USDOT	U.S. Department of Transportation
U.S.C.	United States Code
USDOI	U.S. Department of the Interior
USGS	U.S. Geological Survey
UTM	Universal Transverse Mercator
WEAP	Worker Environmental Awareness Program
WPA	Works Progress Administration

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Cultural Resources

Appendix CUL-1: Department of Energy’s Correspondence with Tribes

NATIONAL ENERGY TECHNOLOGY LABORATORY
Albany, OR • Morgantown, WV • Pittsburgh, PA

U.S. DEPARTMENT OF ENERGY

May 10, 2012

Ms. Kathy Morgan, Chairperson
Tejon Indian Tribe
2234 – 4th Street
Wasco, CA 93280

SUBJECT: Proposed Hydrogen Energy California Project in Kern County, California

Dear Ms. Morgan:

The purpose of this letter is to inform you of the proposed Hydrogen Energy California Project (HECA or the Project) in Kern County, California that is under consideration for approval and potential future funding by the U.S. Department of Energy (DOE). HECA is proposed by Hydrogen Energy California LLC. The Project is part of DOE's Clean Coal Power Initiative, a cost-shared collaboration between the federal government and private industry to increase investment in low-emission coal technology by demonstrating advanced coal-based power generation technologies at commercial scale. DOE has determined that the Project is a federal undertaking as defined in 36 Code of Federal Regulations § 800.16(y). The HECA is supported in part by DOE with a $408 million grant in a cost-shared arrangement. Total project costs are estimated to be approximately $4 billion. In compliance with Section 106 of the *National Historic Preservation Act of 1966* (NHPA), DOE would like to initiate informal government-to-government consultation with the Tejon Indian Tribe.

The Project consists of an Integrated Gasification Combined Cycle power facility, with an integrated manufacturing complex, which will produce low-carbon nitrogen-based products, such as fertilizer. The Project will utilize a blend of coal and petroleum coke as a feedstock in order to produce hydrogen-rich syngas fuel through a gasification process. This fuel will be used in a combustion turbine to produce a nominal 300 megawatts (MW) of electricity, and in the manufacturing complex to produce low-carbon nitrogen-based products such as fertilizers. The production of electricity, low-carbon nitrogen-based products, and carbon dioxide (CO_2) for enhanced oil recovery (EOR) enables the operational flexibility to meet market demand. Because it produces several products, HECA is sometimes referred to as a "polygeneration" project.

The electricity and other products produced by the Project will have a smaller carbon footprint than similar products produced from traditional fossil fuel sources. This is accomplished primarily by capturing approximately 90 percent of the CO_2 from the gasification process. Captured CO_2 will be transported (via a pipeline) for use in EOR, which results in sequestration of the CO_2 in secure geologic formations, at the nearby Elk Hills Oil Field (EHOF). EHOF is owned and operated by Occidental of Elk Hills, Inc. (OEHI) which will obtain necessary permits for the EOR operations.

The 453-acre Project site is located approximately 7-miles west of the outermost edge of the city of Bakersfield and 1.5-miles northwest of the unincorporated community of Tupman in western Kern County, California. The majority of the Project site is presently used for agricultural purposes, including

3610 Collins Ferry Road, P.O. Box 880, Morgantown, WV 26507
fred.pozzuto@netl.doe.gov • Voice (304) 285-5219 • Fax (304) 285-4403 • www.netl.doe.gov

cultivation of cotton, alfalfa, and onions. Temporary construction activities, including equipment storage, construction laydown, parking and offices, will be located on the Project site and within an adjacent 91-acre construction laydown area.

The Project also includes the following off-site facilities:

- Rail Spur – A new rail spur will be constructed to the Project site in order to facilitate feedstock and equipment delivery, as well as product and by-product off-take. The rail spur will extend approximately 4.6-miles from the existing San Joaquin Valley Railroad to the Project site.
- Electrical Transmission Line – An electrical transmission line will interconnect the Project to a future Pacific Gas & Electric (PG&E) switching station to the east of the Project site (adjacent to the existing Midway-Wheeler Ridge transmission lines). The electrical transmission line is approximately 3.5-miles long, of which 1.5-miles will be located within the Project site.
- Natural Gas Supply Line – A natural gas interconnection will be made with an existing PG&E natural gas pipeline that is located north of the Project site. The natural gas pipeline is approximately 11.1-miles in length.
- Water Supply Pipelines – The Project will utilize brackish groundwater supplied from the Buena Vista Water Storage District located northwest of the Project site. The raw water supply pipeline will be approximately 14.4-miles in length. Potable water for construction, drinking, and sanitary use will be delivered from a new West Kern Water District potable water production site approximately 1.3-miles east of the Project site.
- CO_2 Pipeline – The CO_2 pipeline will transfer the CO_2 captured during gasification from the Project site south to the EHOF for EOR and sequestration (storage). The CO_2 pipeline is approximately 3.4-miles in length.

As indicated above, DOE wishes to initiate informal consultation with the Tejon Indian Tribe in compliance with Section 106 of the NHPA. For your additional information, for the purposes of initiating informal consultation with the California Office of Historic Preservation on the delineation of the area of potential effects (APE), DOE is defining the APE for archaeological resources as all areas where ground-disturbing activities will occur in relation to the Project. More specifically, 200-feet from the Project site and Construction Laydown Area, and 50-feet from the right of way of all Project linears. The APE for historic architecture is defined as 0.5-miles around the Project site and 0.5-miles from the electric transmission and rail spur right of ways to account for potential indirect effects. Attached are copies of the proposed APEs for both archaeological and historic architectural resources.[1] The APEs for archaeological and historic architectural resources are consistent with the requirements of the California Energy Commission (CEC), which has exclusive authority for licensing thermal power plants in California with a generating capacity of 50-MW or more.

DOE's Section 106 consultation under the NHPA for the undertaking with the California State Historic Preservation Office is to further seek concurrence on the delineation of APEs for both archaeological

[1] Note that the identified APEs may be over-inclusive in the sense that they include the sites of the EOR to be undertaken by OEHI, which is not a recipient of federal funding in connection with its EOR activities.

and historic architectural resources. A joint CEC/DOE environmental impact statement (EIS) is currently being prepared for the project, and the draft version will be made available to you at a later date where you may again respond to any specific concerns you may have. DOE will include correspondence with your office in an appendix to the EIS. HECA's full application to the CEC can also be viewed at:
http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/index.html#applicant

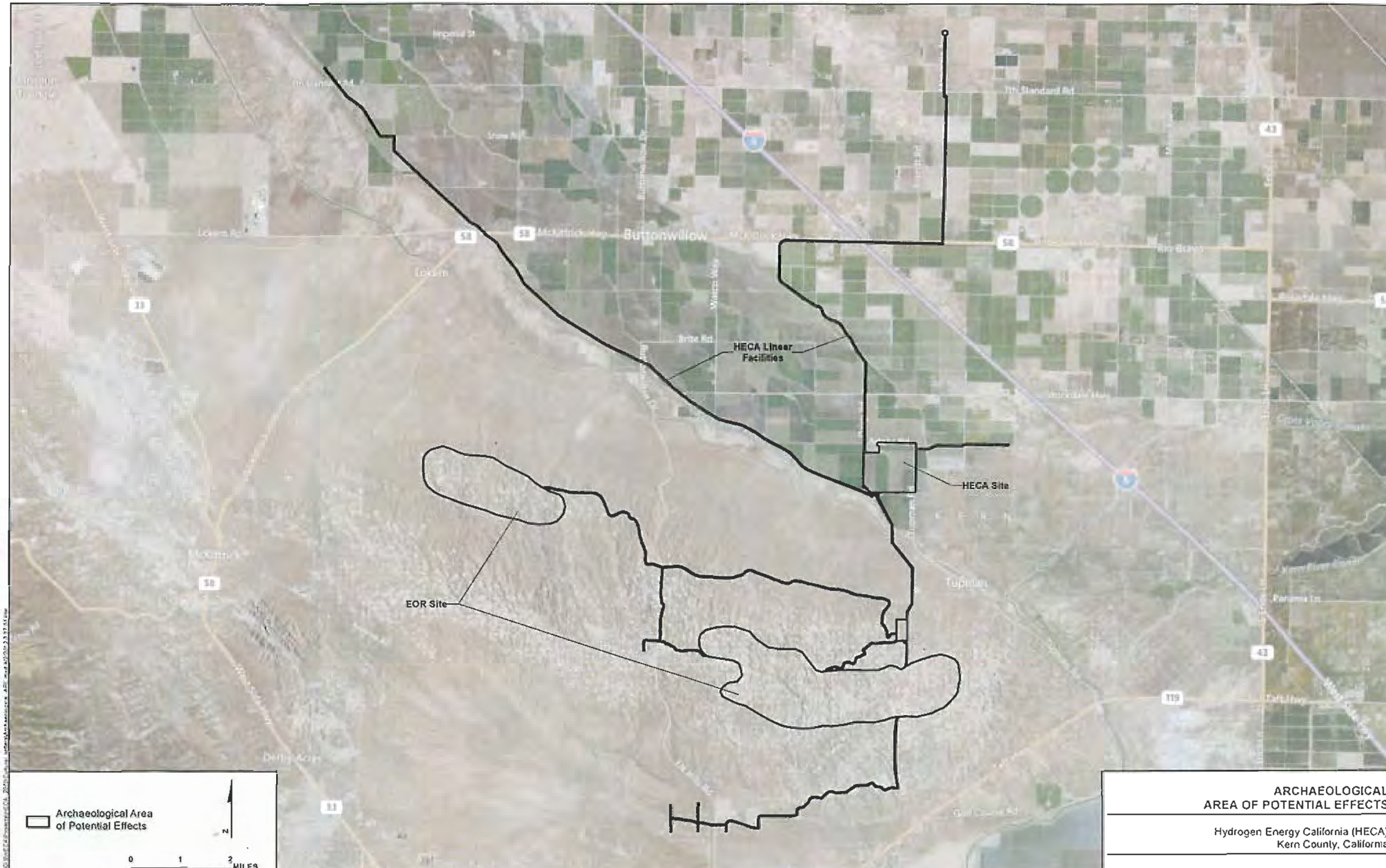
For any overall environmental project questions please contact me at 304-285-5219. Should you have any technical questions please contact the Office of National Environmental Policy Act (NEPA) contractor, Mr. Dale Shileikis at 415-243-3708, or by email @ dale.shileikis@urs.com.

Sincerely,

Fred Pozzuto
Environmental Manager / NEPA Compliance Officer

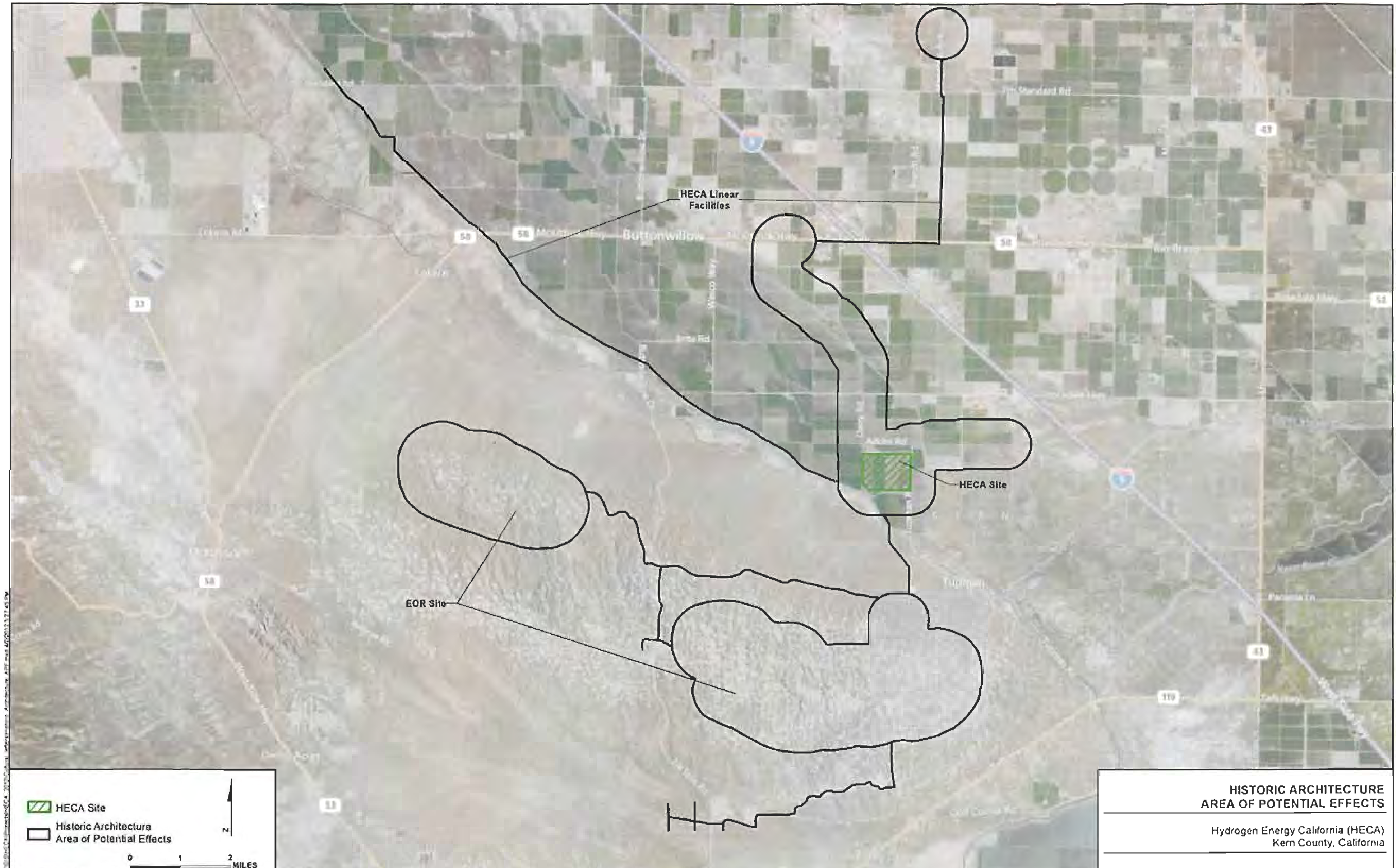
Enclosures:

cc:
M. Mascaro - HECA-SCS Energy
D. Shileikis - URS



ARCHAEOLOGICAL
AREA OF POTENTIAL EFFECTS

Hydrogen Energy California (HECA)
Kern County, California



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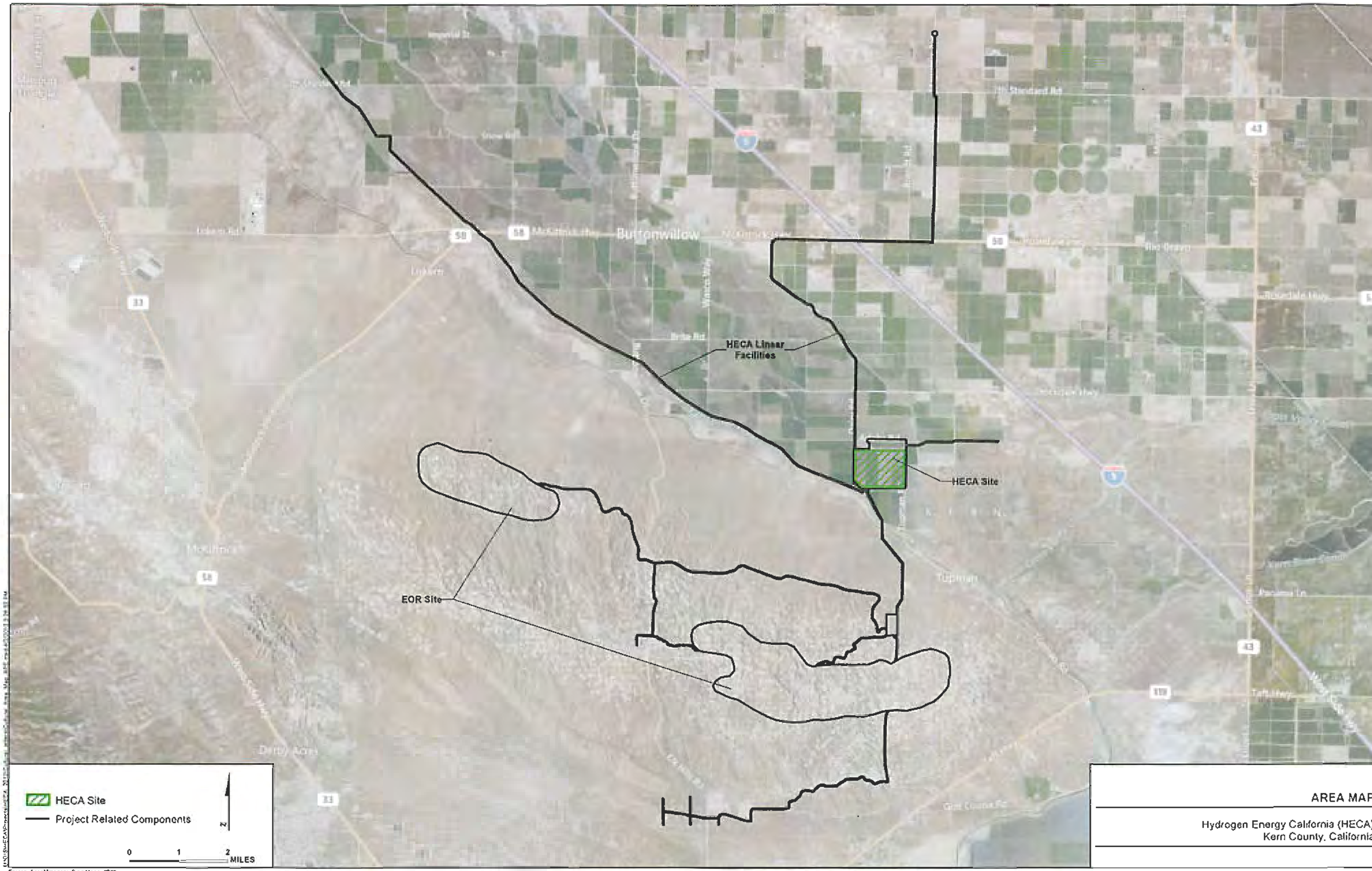

HECA Linear Facilities
HECA Site
EOR Site
Buttonwillow
Tupman
HECA Site
Project Related Components
0
1
2
MILES
AREA MAP
Hydrogen Energy California (HECA)
Kern County, California

TEJON
INDIAN TRIBE

June 5, 2012

National Energy Technology Laboratory
Fred Pozzuto
P.O. Box 880
Morgantown, WV 26507

Re: Proposed Hydrogen Energy California Project in Kern County, California

Dear Fred Pozzuto,

Thank you for the letter and the opportunity to comment on this project. Tejon Indian Tribe has no conflict with this project nor do we know of any cultural resources that might be impacted at this site. However, we ask that you notify us immediately if any site/s and / or artifacts are discovered during your project in the area.

Sincerely,

Kathryn Montes Morgan
Tribal Chair
Tejon Indian Tribe

1731 Hasti Acres Drive, Suite 108 Bakersfield, CA 93309 (661) 834-8566

Cultural Resources

Appendix CUL-2: Department of Energy's Correspondence with the State Historic Preservation Officer

April 24, 2013

Ms. Carol Roland-Nawi
State Historic Preservation Officer
California State Department of Parks and Recreation
P.O. Box 942896
Sacramento, CA 94296-0001

Dear Ms. Roland-Nawi:

The purpose of this letter is to provide supplemental information on the Hydrogen Energy California (HECA) Project in Kern County, California, and to seek concurrence on the delineation of the Area of Potential Effects (APE) for both archaeological and historic architectural resources in compliance with Section 106 of the National Historic Preservation Act of 1966 (NHPA).

On May 8, 2012, U.S. Department of Energy (DOE) transmitted a letter to your predecessor, Milford W. Donaldson, initiating Section 106 consultation under the NHPA. In addition, DOE sought concurrence from your office for the HECA Project's proposed APE for both archaeological and historic architectural resources. On May 25, 2012, Ms. Jenan Saunders, on behalf of Mr. Donaldson, indicated by reply letter that the State Historic Preservation Officer was unable to concur on the delineation of the proposed APE, citing a lack of sufficient information. This letter is intended to provide the required information

Background on the HECA Project

The HECA Project proposed by Hydrogen Energy California LLC consists of an Integrated Gasification Combined-Cycle (IGCC) project, with an Integrated Manufacturing Complex that will produce low-carbon nitrogen-based fertilizer. The HECA Project will gasify a 75 percent coal and 25 percent petroleum coke fuel blend to produce synthesis gas. Syngas produced via gasification will be purified to hydrogen-rich fuel, which will be used to generate low-carbon baseload electricity in a Combined-Cycle Power Block, low-carbon nitrogen-based fertilizers in an integrated manufacturing complex, and carbon dioxide (CO_2) for use in enhanced oil recovery (EOR).

The electricity and other products produced by the HECA Project will have a smaller carbon footprint than similar products produced from traditional fossil fuel sources through a conventional combustion process. This is accomplished primarily by capturing approximately 90 percent of the CO_2 from the gasification process. Captured CO_2 will be transported (via a pipeline) for use in EOR, which results in the sequestration of the CO_2 in secure geologic formations, at the nearby Elk Hills Oil Field (EHOF). EHOF is majority owned and operated by Occidental of Elk Hills, Inc. (OEHI), which will obtain necessary permits for the EOR operations.

The DOE is providing financial assistance to the HECA Project under the Clean Coal Power Initiative Round 3 via a cost-sharing agreement with HECA LLC, covering project construction and a "Demonstration Period" for the first 2 years of project operations. DOE financial assistance for the construction and operation of the HECA Project during the Demonstration Period constitutes the DOE undertaking for purposes of Section 106 of the NHPA. OEHI's EOR facility discussed above is a necessary component of the Demonstration Period; therefore, it is also subject to compliance with Section 106.

The HECA Project requires certification from the California Energy Commission (CEC). The DOE and CEC will prepare a joint Environmental Impact Statement/Staff Assessment to satisfy the requirements of the National Environmental Policy Act (NEPA) and the California Environmental Quality Act.

Description of the Federal Undertaking

The 453-acre HECA Project Site is approximately 7 miles west of the outermost edge of the city of Bakersfield and 2 miles northwest of the unincorporated community of Tupman in western Kern County. The HECA Project Site is currently used for farming, including cultivation of cotton, alfalfa, and onions.

The majority of the excavations (approximately 90 percent) required for construction of the HECA IGCC polygeneration facility are expected to be in the range of 5 to 10 feet below existing grade. Excavation in areas such as the gasification structure, the cooling tower pump basin, and the feedstock unloading bunker will be in the range of 15 to 50 feet below existing grade. Shallow soil-bearing foundations will be used for the majority, if not all, of the foundations. Pile foundations may be used in selected high-load applications, with piles extending approximately 40 feet below existing ground elevations. Temporary construction activities, including equipment storage, offices, construction laydown, parking and offices, will be located on the HECA Project Site and within an adjacent 91-acre Construction Laydown Area. A fence will be constructed around the HECA Project Site and adjacent agricultural lands that will also be purchased by HECA.

The HECA Project also includes the following offsite components:

- Rail Spur – A new rail spur will be constructed to the HECA Project Site to facilitate feedstock and equipment delivery, as well as product and by-product off-take. The rail spur will extend approximately 5.3 miles from the existing San Joaquin Valley Railroad to the HECA Project Site. The excavation for the rail spur will be between 6 inches and 3 feet, with an average depth of less than 2 feet. The exception being where the rail spur is proposed to cross the East Side Canal.

- Electrical Transmission Line – An electrical transmission line will interconnect the HECA Project to a future Pacific Gas and Electric Company (PG&E) switching station to the east of the HECA Project Site (adjacent to the existing Midway–Wheeler Ridge transmission lines). The electrical transmission line is approximately 3.6 miles long, of which 1.5 miles will be located within the HECA Project Site. The foundations of tangent towers (straight line towers) will be approximately 28 feet in depth. The foundations of turning towers will be approximately 35 feet in depth.

- PG&E Switching Station – A new 230-kilovolt (kV) switching station will be constructed, allowing the Midway–Wheeler Ridge 230-kV Lines No. 1 and 2 to loop into and out of the switching station, and providing interconnection positions for the HECA generator tie line. The electric transmission switching station will be designed, constructed, owned, and operated by PG&E. The area for the switching station is approximately 4 acres in size. The maximum excavation depth is expected to be 9 feet. It is anticipated that dead-end structures would be required on the western and eastern ends of the station to terminate the transmission line from the HECA Project Site, incoming lines from the Midway Substation, and outgoing lines to the Wheeler Ridge Substation.

- Natural Gas Supply – A natural gas interconnection will be made with an existing PG&E natural gas pipeline north of the HECA Project Site. The natural gas pipeline is approximately 13 miles in length. The excavation for the natural gas pipeline is expected to be approximately 7 feet. At the interconnection, a metering station will be constructed. The metering station will be up to 100 feet by 100 feet, and will be surrounded by a chain link fence. The metering station will be excavated to approximately 6 feet.

- Water Supply Pipelines – The Project will use brackish groundwater supplied from the Buena Vista Water Storage District, northwest of the HECA Project Site. The raw water supply pipeline will be approximately 15 miles in length. The process water line will be in a trench expected to be up to 5 feet in depth, with the trench being excavated in the road atop the levee adjacent to the West Side Canal. Potable water for construction, drinking, and sanitary use will be delivered from a new West Kern Water District potable water production site approximately 1 mile east of the HECA Project Site. The potable water pipeline will be placed in a trench excavated to a depth of 6 feet.

The OEHI Project will include construction and operation of the following three primary EOR components during the Demonstration Period:

- CO_2 Pipeline – The CO_2 pipeline will transfer the CO_2 captured during gasification from the plant at the HECA Project Site south to the EHOF for EOR and resulting simultaneous sequestration (storage). The CO_2 pipeline is approximately 3.4 miles in length. Most of this pipeline will be installed in a trench excavated to an average depth of approximately 7 feet. Some sections will require the use of horizontal directional drilling (HDD) to avoid interference with water conveyance features, including the California Aqueduct and the West Side Canal. The depth of these HDD crossings is expected to be 50 to 100 feet below current ground surface elevations.

- CO_2 EOR Processing Facility – The CO_2 EOR processing facility will permanently occupy approximately 61 acres in the EHOF. Up to 50 feet of excavation may be required in some areas for grading associated with the CO_2 EOR processing facility. The maximum depth of excavation for associated equipment foundations is expected to be approximately 6 feet below grade.

- Satellite Gathering Stations – Three Satellite Gathering Stations (satellites) will provide primary separation of the oil/water and gas from the production well stream during the Demonstration Period. The satellites will use existing pipelines as well as existing producing and injection wells. New pipelines may also be installed in certain locations, however no detailed design information is available at this time. Each Satellite Gathering Station is expected to be 230 by 200 feet. The maximum depth of excavation for the Satellite Gathering Stations is expected to be 10 feet.

Proposed Area of Potential Effects

For purposes of the Section 106 consultation, DOE proposes to define the APE for archaeological resources as all areas where ground-disturbing activities will occur in relation to the HECA and OEHI Projects. More specifically, the APE includes all Project components as well as all areas within 200 feet from Project facilities and 50 feet from the construction right-of-way of all Project linears (i.e., process/potable water, natural gas, electrical transmission, rail spur, and carbon dioxide). DOE proposes to define the APE for historic "built environment" resources as inclusive of the footprint of all HECA and OEHI Project components and an additional 0.5 mile around all aboveground Project components.

The APEs for archaeological and historic architectural resources defined above, in particular the inclusion of buffer areas, are consistent with the requirements of the CEC, which has exclusive authority for licensing thermal power plants in California with a generating capacity of 50 megawatts or more.

Table 1 lists the Project components and the areas used to establish both the vertical and lateral extent of the APEs.

Attached are figures depicting the proposed APEs for both archaeological and historic architectural resources.

Cultural Resource Inventory Results to Date

As of the date of this letter, several efforts to inventory cultural resources within the APEs proposed for the HECA and OEHI Project components have been conducted. Table 2 provides the archaeological resources currently identified within the HECA Project components and their physical relationship to the proposed APE as defined for archaeological resources. The applicant's intent is to avoid all identified archaeological resources. DOE is actively working with CEC and the Applicant to develop appropriate avoidance measures.

Table 1
APE by Project Component

Project Component	Maximum Depth of Disturbance (feet)	Approximate Acres/ Length	Archaeological Buffer per CEC Guidelines (feet)	Historic Architecture per CEC Guidelines Buffer (miles)
HECA IGCC Polygeneration Facility	**50**	**453 acres**	**200**	**0.5**
Rail Spur	**3**	**5.3 miles**	**50**	**0.5**
Electrical Transmission Line	**35**	**2.1 miles**	**50**	**0.5**
PG&E Switching Station	**9**	**4 acres**	**200**	**0.5**
Natural Gas Supply	**7**	**13 miles**	**50**	**0 (none required)**
Process Water Pipeline	**5**	**15 miles**	**50**	**0 (none required)**
Potable Water Pipeline	**6**	**1 mile**	**50**	**0 (none required)**
CO_2 Pipeline	**7 (trenching) 50 to 100 (HDD)**	**3.4 miles**	**50**	**0 (none required)**
CO_2 EOR Processing Facility	**50**	**61 acres**	**200**	**0.5**
Three Satellite Gathering Stations	**10**	**1 acre each**	**50**	**0.5**

Note: Per CEC Guidelines, below ground installations do not require a buffer area to be added to the Historic Architecture APE.

Cultural resources inventory efforts conducted to date have also included surveys for historic architectural resources. Table 3 lists the historic architectural resources currently identified within the HECA Project components and their relationship to the APE as defined for historic architectural resources. Two of the identified historic architectural resources have been found eligible for inclusion to the National Register of Historic Places and/or California Register of Historical Resources. However, neither of these resources will be affected by Project implementation.

Cultural resources inventory efforts within the APE as defined for the OEHI Project components are on-going and the results of these investigations along with those completed for the HECA Project will be forwarded to you when a formal finding of effects has been developed.

Table 2
Archaeological Resources Currently Identified Within the Proposed APE

Primary # (P-15) or Temporary Designation	Site Type	Prehistoric/ Historic	Associated Project Component	NRHP/ CRHR Status	Within APE per CEC Guidelines	Within Close Proximity to APE
89	Lithic and Trash Scatter with Human Remains	Prehistoric/ Historic	Process Water Pipeline	Not Evaluated	No	Yes
171	Burial Mound	Prehistoric	Process Water Pipeline	Not Evaluated	Yes	No
179	Burial Mound	Prehistoric	Process Water Pipeline	Not Evaluated	No	Yes
2485 and BS-IF-003	Lithic Scatter	Prehistoric	Process Water Pipeline	Not Evaluated	No	Yes
3108	Lithic Scatter	Prehistoric	Natural Gas Pipeline and Rail Spur	Not Evaluated	Yes	No
HECA-2008-1	Lithic and Shell Scatter	Prehistoric	Process Water Pipeline	Not Evaluated	Yes	No
HECA-2009-2	Lithic Scatter	Prehistoric	CO_2 Pipeline	Not Evaluated	Yes	No
HECA-2009-9	Lithic Scatter	Prehistoric	Process Water, Well Field	Not Evaluated	Yes	No
HECA-2009-10	Lithic Scatter	Prehistoric	Process Water, Well Field	Not Evaluated	Yes	No
HECA-2010-1	Lithic Scatter	Prehistoric	Electrical Transmission/ Switching Station	Not Evaluated	Yes	No
HECA-2010-2	Foundation and Trash Scatter	Historic	Natural Gas Pipeline and Rail Spur	Not Evaluated	Yes	No

Notes:
APE = Area of Potential Effects
CO_2 = Carbon Dioxide
CRHR = California Register of Historical Resources
HECA = Hydrogen Energy California
NRHP = National Register of Historic Places

Table 3
Historic Architectural Resources Currently Identified Within the Proposed APE

Address or Resource Name	Year Built	Associated Project Component	NRHP/CRHR Status
Relocated Structures North of SR 58	Unknown, moved to site after 1973	Natural Gas Pipeline and Rail Spur	Ineligible
Southern Pacific McKittrick (Asphalto) Branch	1893	Natural Gas Pipeline and Rail Spur	Ineligible
Pacific Gas & Electric/Southern California Edison Transmission Lines & Towers	ca. 1943-53 ca. 1956-68 ca. 1968-73	Natural Gas Pipeline and Rail Spur	Ineligible
6010 Buerkle Road	1964	Natural Gas Pipeline and Rail Spur	Ineligible
35034 Stockdale Highway	ca. 1940s	Natural Gas Pipeline and Rail Spur	Ineligible
Works Projects Administration Culverts	1940	Project Site, Natural Gas Pipeline, and Rail Spur	Ineligible
7307 Adohr Road (Adohr Farms)	1930	Project Site, Natural Gas Pipeline, and Rail Spur	Ineligible
7307 Adohr Road (Palm Farms)	1953	Project Site, Natural Gas Pipeline, and Rail Spur	Ineligible
7345 Adohr Road	1930	Project Site, Natural Gas Pipeline, and Rail Spur	Ineligible
Old Headquarters Weir	1911	Project Site and Process Water Pipeline	Eligible
California Aqueduct	1961-72	Project Site and CO_2 Pipeline	Eligible
6122 Tule Park Road	1941	Project Site and Electrical Transmission/ Switching Station	Ineligible
Tupman Water Plant	ca. 1935, 1974-81	Electrical Transmission/Switching Station	Ineligible
Canals	1876-1918	Various	Ineligible

Notes:

APE = Area of Potential Effects
CO_2 = Carbon Dioxide
CRHR = California Register of Historical Resources
HECA = Hydrogen Energy California
NRHP = National Register of Historic Places

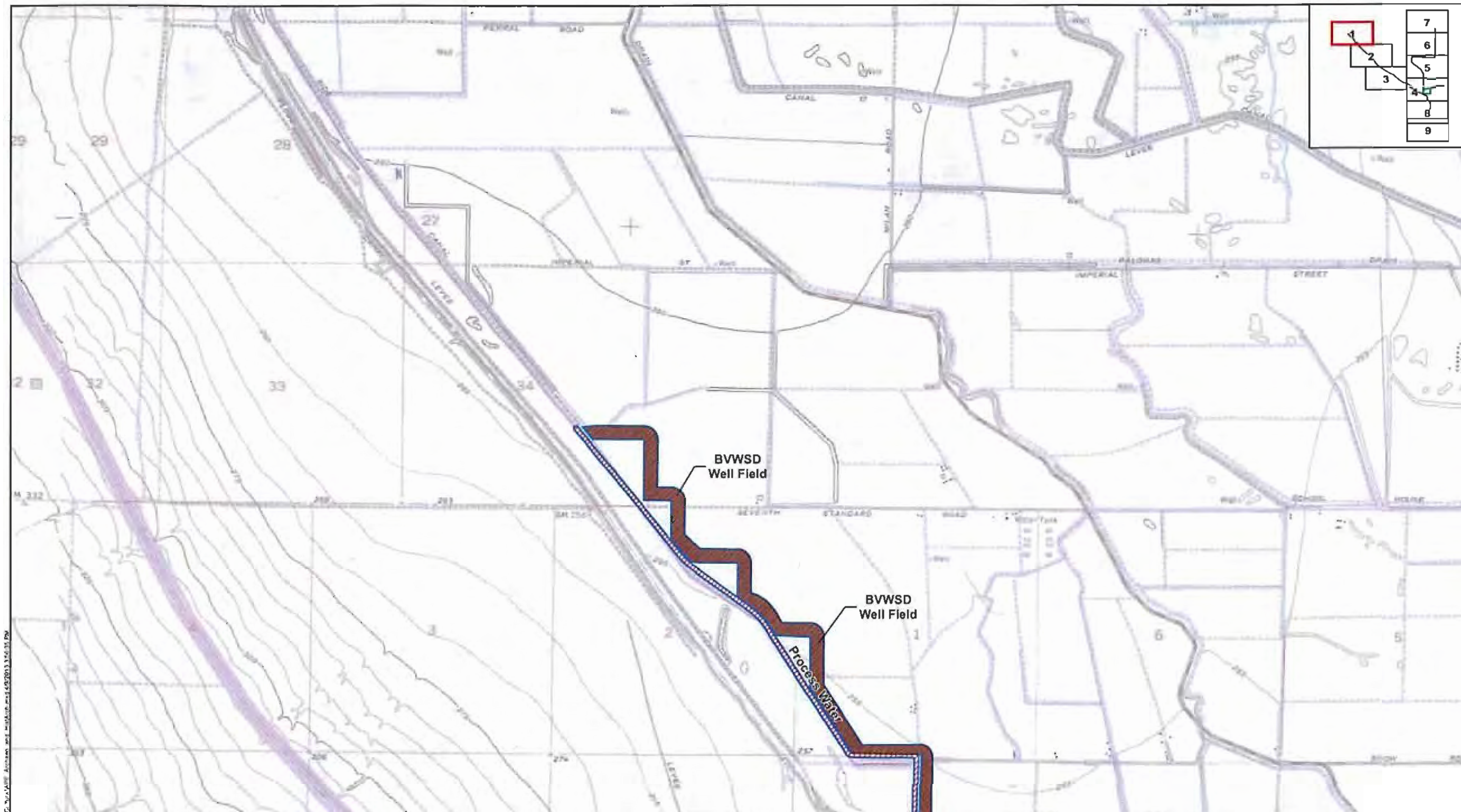
As discussed at the beginning of this correspondence, DOE is providing supplemental information on the proposed federal undertaking and is requesting your concurrence on the delineation of the respective APEs for both archaeological and historic architectural resources. DOE looks forward to working with you as part of the Federal Section 106 consultation process. For overall environmental project questions, please contact me at (304) 285-5219 or by email at fred.pozzuto@netl.doe.gov. Should you have technical questions, please contact the NEPA contractor, Mr. Dale Shileikis at (415) 243-3826, or by email at dale.shileikis@urs.

Sincerely,

Fred Pozzuto
Environmental Manager/
NEPA Compliance Officer

Enclosures:

cc: G. Roark – California Energy Commission
M. Mascaro – HECA – SCS Energy
D. Shileikis – URS Corporation
M. Coalmer – Occidental of Elk Hills, Inc.



Project Site
Construction Staging Area
Rail Laydown Yard
Controlled Area Fenceline
Natural Gas Valve Station
Electrical Switching Station
BVWSD Well Field
HDD Entry/Exit Pits
OEHI CO2 EOR Project
EOR Processing Facility & Satellite Gathering Stations
Archaeological Area of Potential Effects
Historic Architectural Area of Potential Effects

N

0 1,000 2,000 FEET

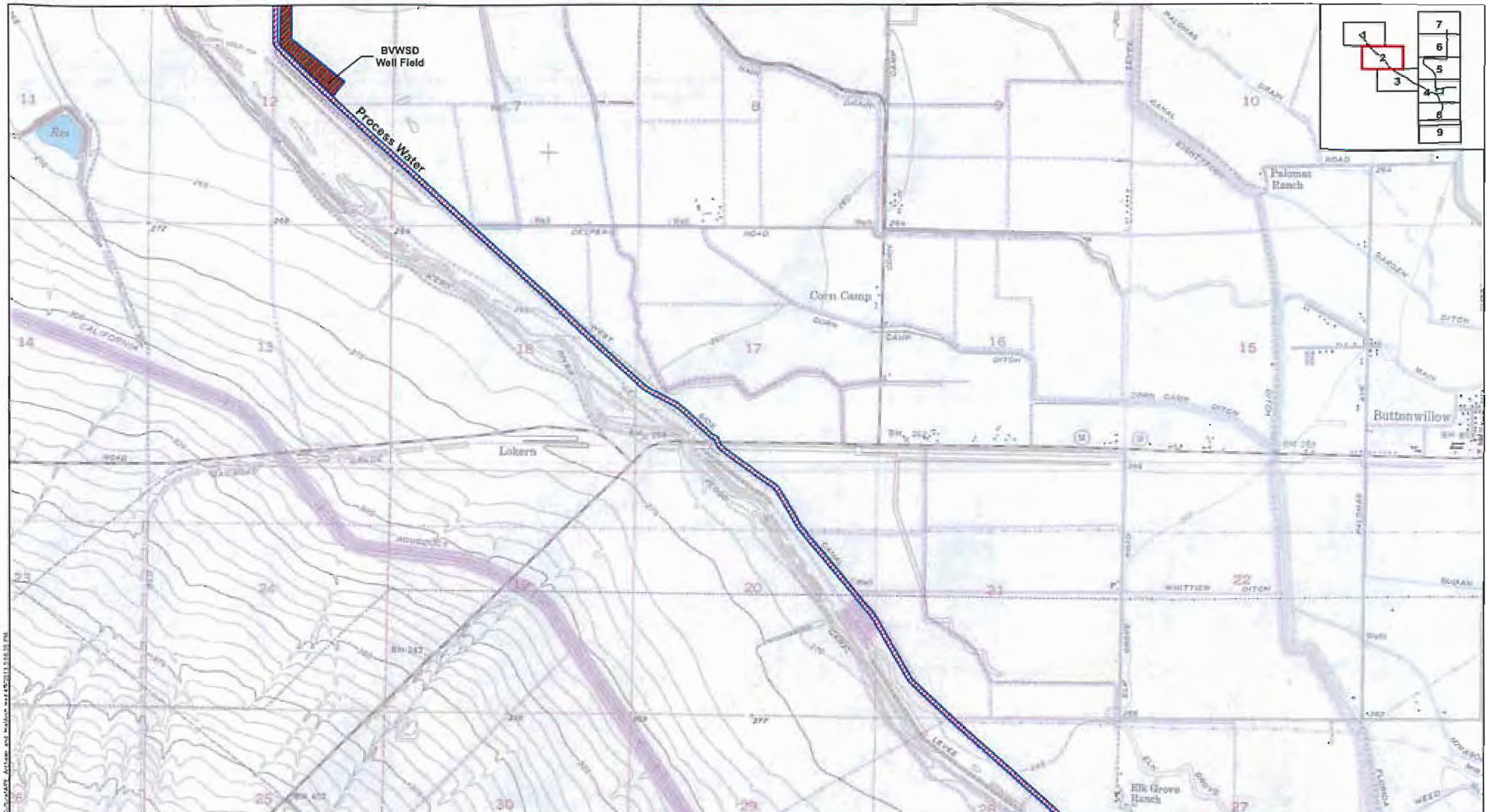
AREA OF POTENTIAL EFFECTS

April 2013
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 1 - SHEET 1



Project Site
Construction Staging Area
Rail Laydown Yard
Controlled Area Fenceline
Natural Gas Valve Station
Electrical Switching Station
BVWSD Well Field
HDD Entry/Exit Pits
OEHI CO2 EOR Project
EOR Processing Facility & Satellite Gathering Stations
Archaeological Area of Potential Effects
Historic Architectural Area of Potential Effects

N

0 1,000 2,000 FEET

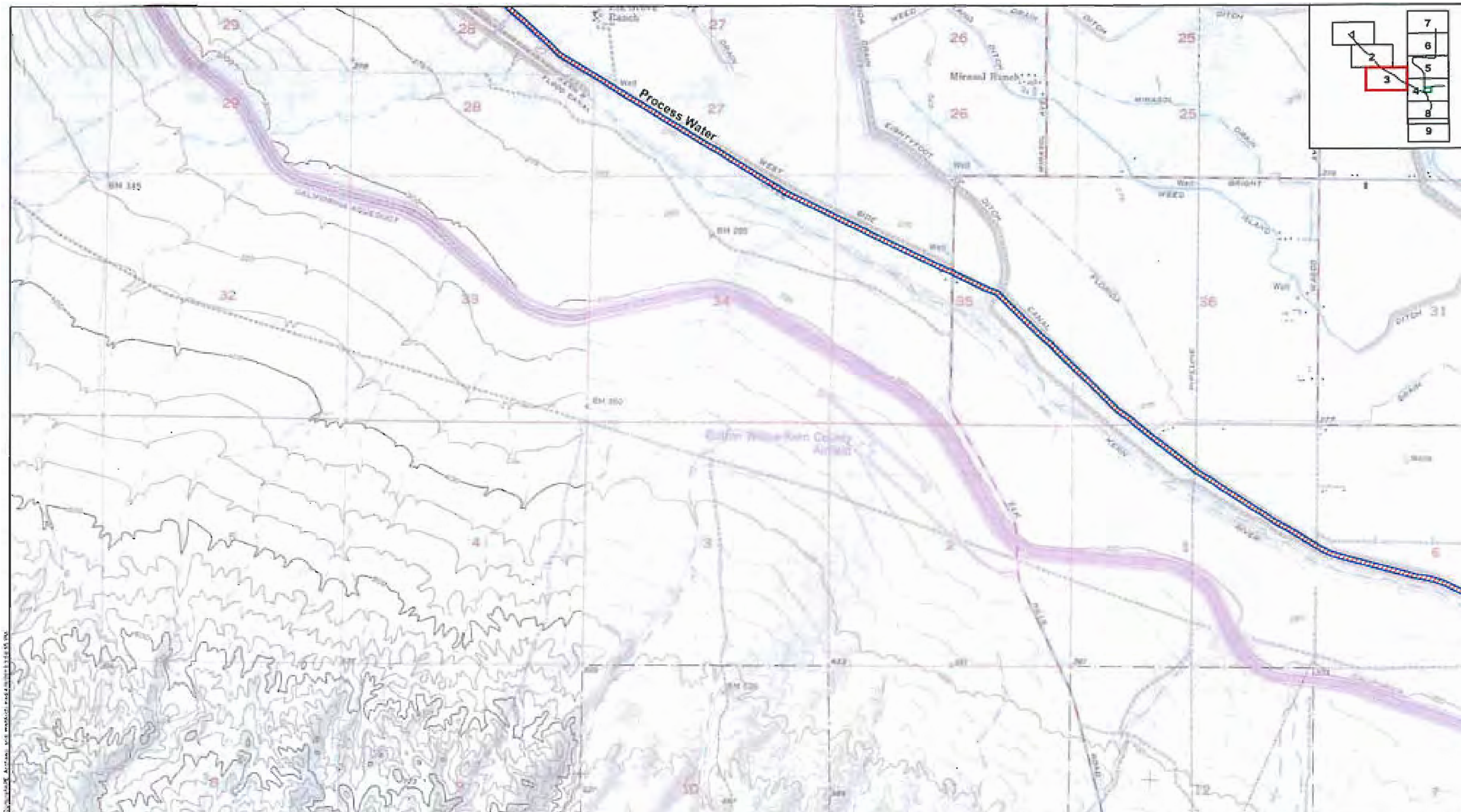
AREA OF POTENTIAL EFFECTS

April 2013
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 1 - SHEET 2



Project Site
Construction Staging Area
Rail Laydown Yard
Controlled Area Fenceline
Natural Gas Valve Station
Electrical Switching Station
BVWSD Well Field
HDD Entry/Exit Pits
OEHI CO2 EOR Project
EOR Processing Facility & Satellite Gathering Stations
Archaeological Area of Potential Effects
Historic Architectural Area of Potential Effects

N

0 1,000 2,000 FEET

AREA OF POTENTIAL EFFECTS

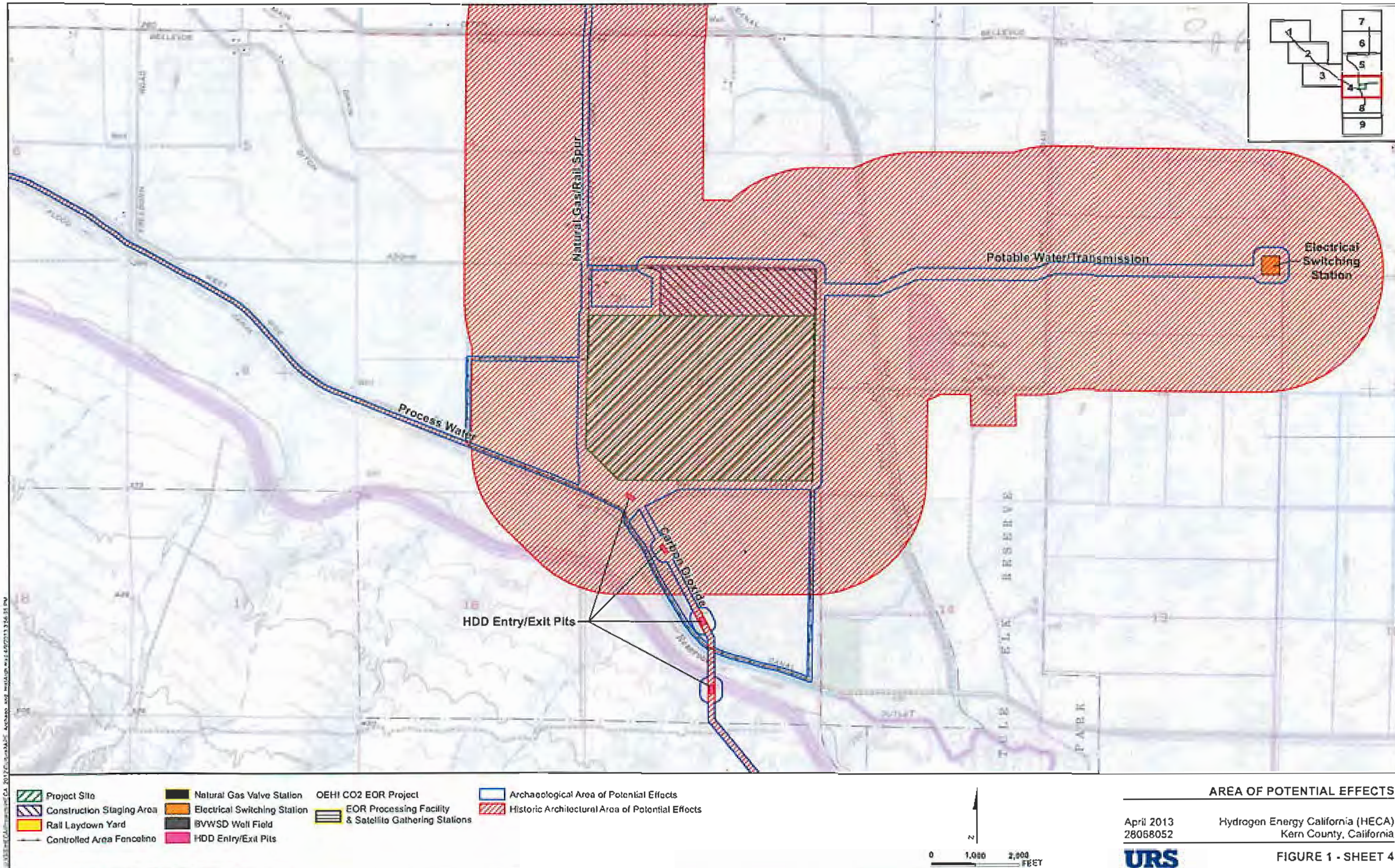
April 2013
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 1 - SHEET 3

Sources: USGS (30'x60' quads: Taft 1982, Delano 1982). Copyright © 2011 National Geographic Society, i-cubed



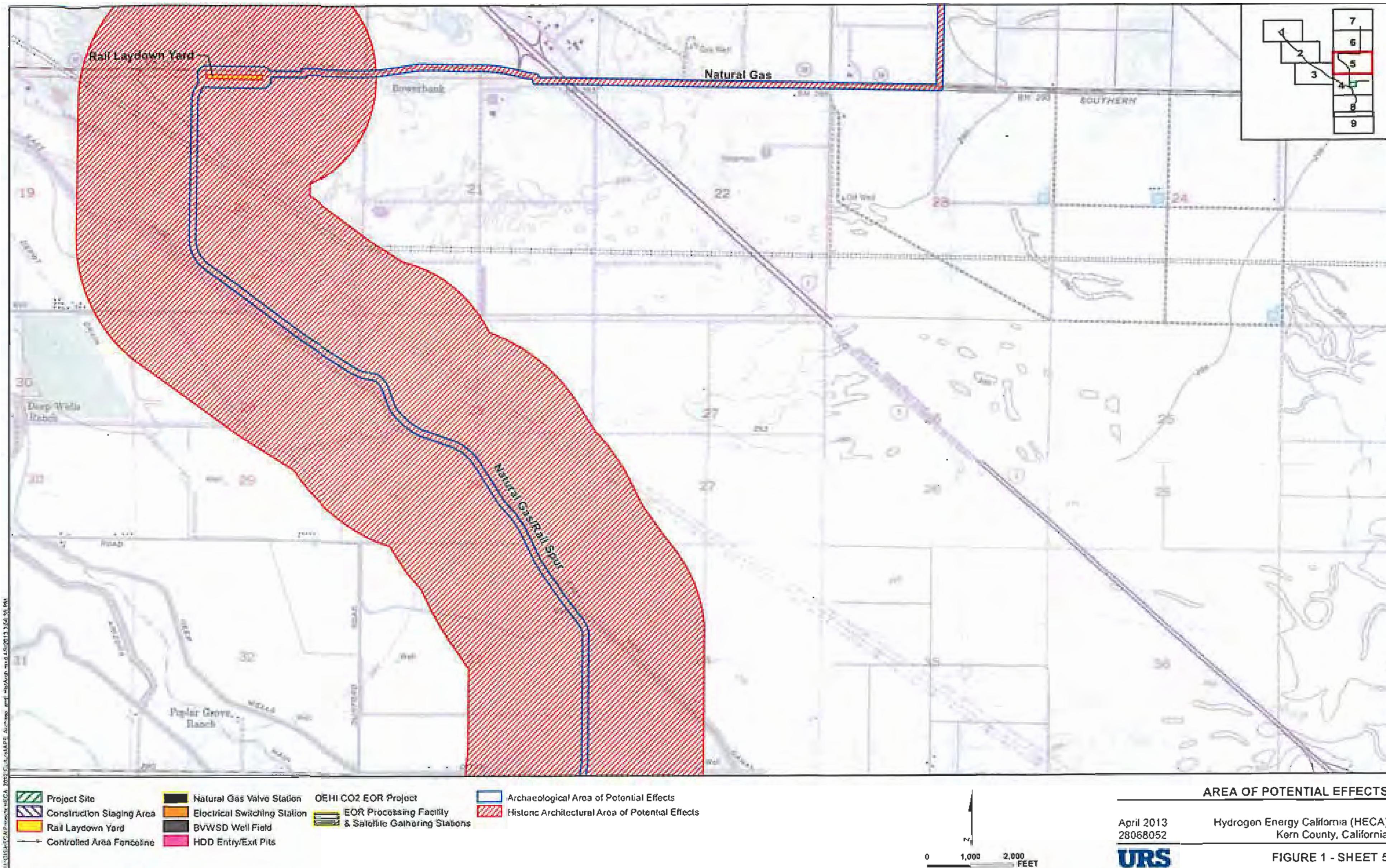
AREA OF POTENTIAL EFFECTS

April 2013
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 1 - SHEET 4



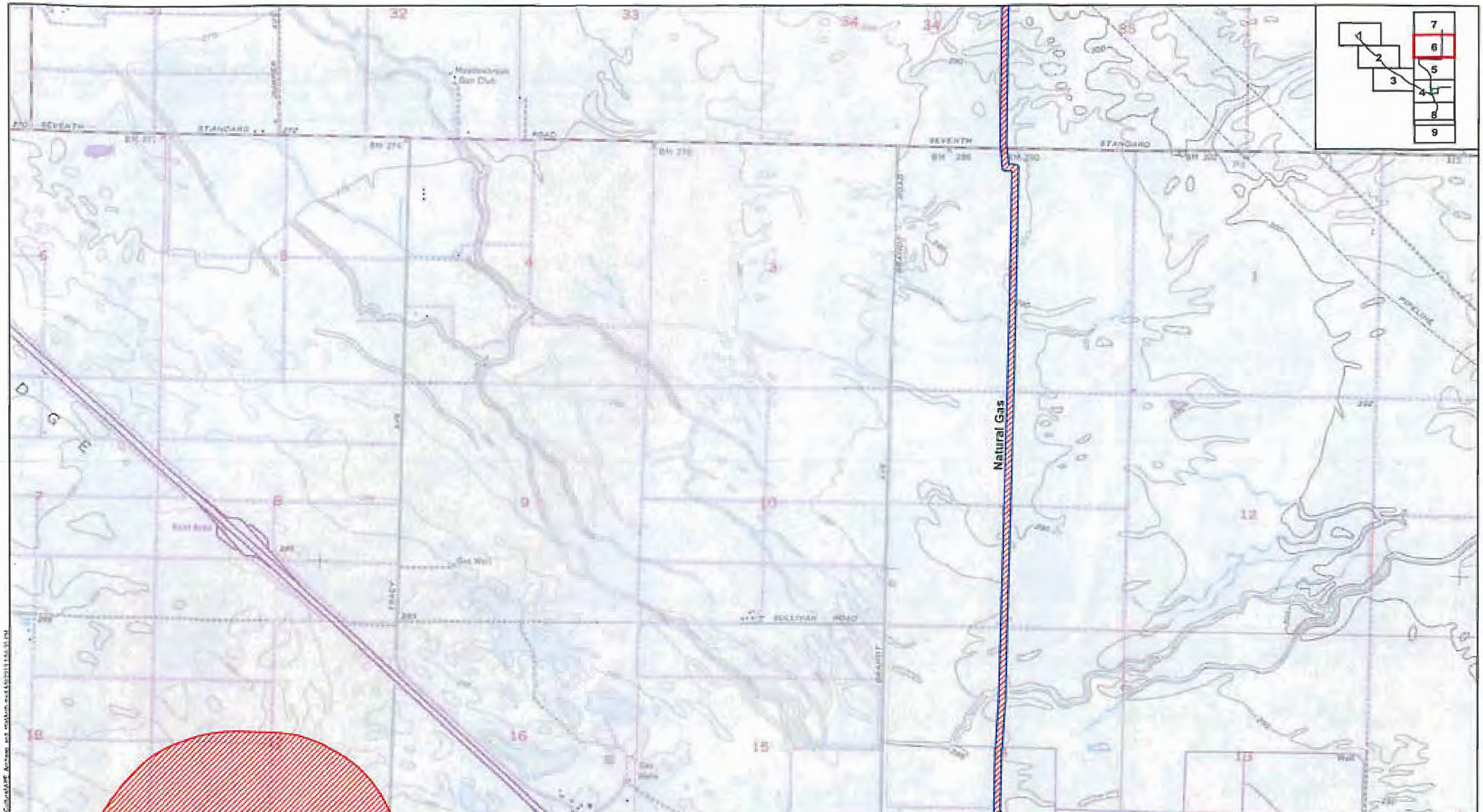
AREA OF POTENTIAL EFFECTS

April 2013
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 1 - SHEET 5



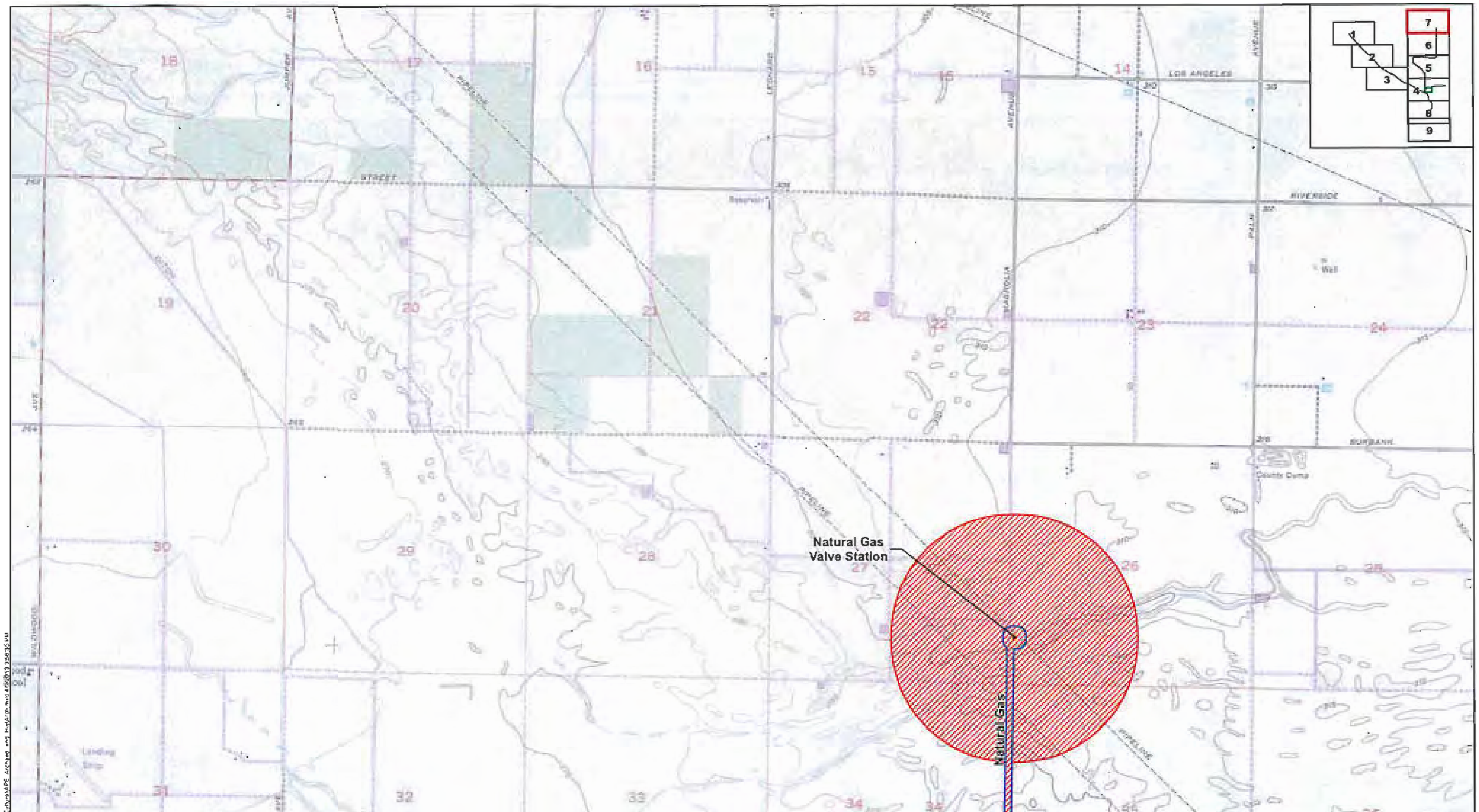
AREA OF POTENTIAL EFFECTS

April 2013
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 1 - SHEET 6



Project Site
Construction Staging Area
Rail Laydown Yard
Controlled Area Fenceline
Natural Gas Valve Station
Electrical Switching Station
BVWSD Well Field
HDD Entry/Exit Pits
OEHI CO2 EOR Project
EOR Processing Facility & Satellite Gathering Stations
Archaeological Area of Potential Effects
Historic Architectural Area of Potential Effects

N

0 1,000 2,000 FEET

AREA OF POTENTIAL EFFECTS

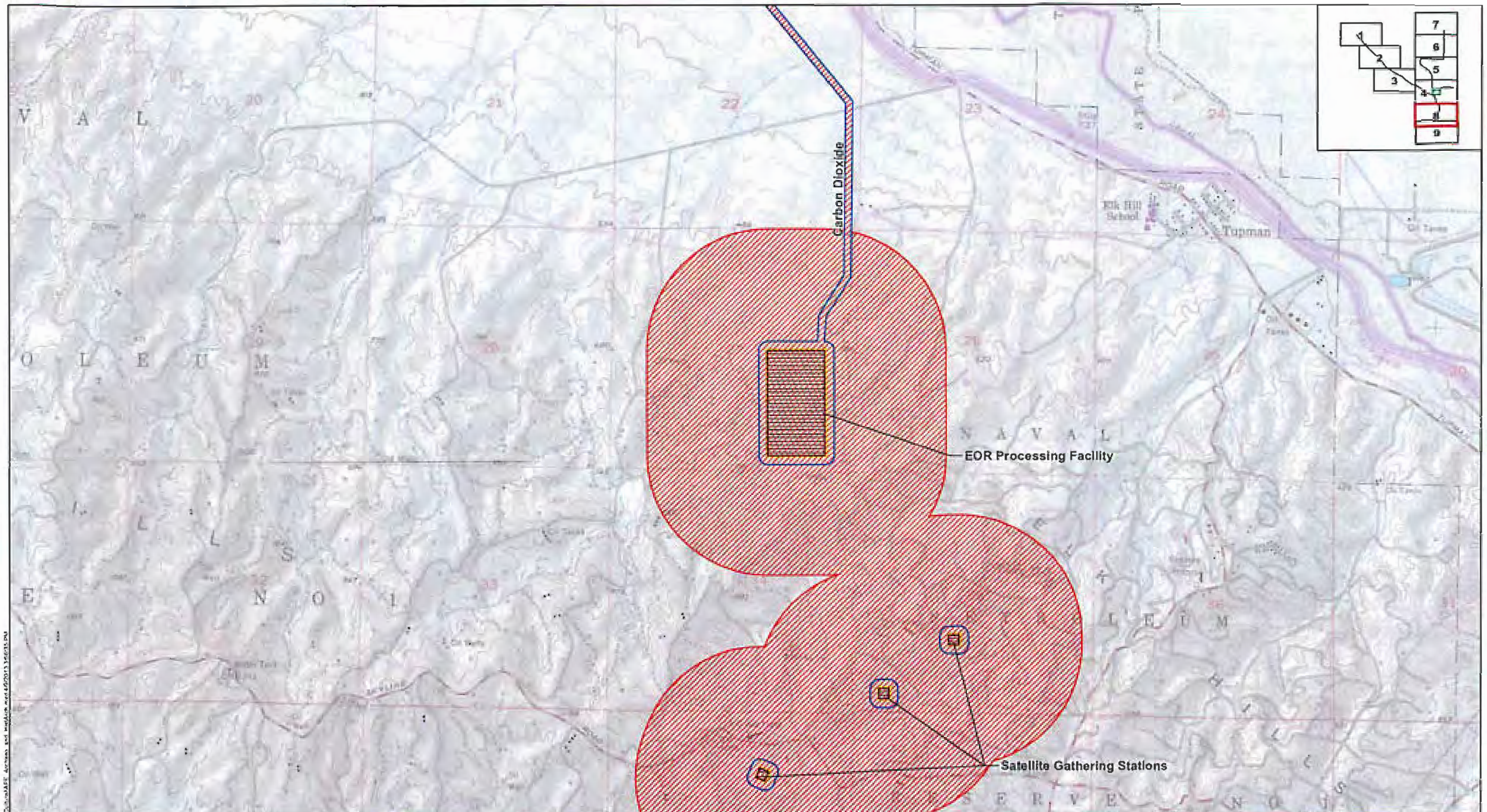
April 2013
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 1 - SHEET 7

Sources: USGS (30'x60' quads: 1:A 1982, Delano 1982), Copyright © 2011 National Geographic Society, i-cubed



Project Site
Construction Staging Area
Rail Laydown Yard
Controlled Area Fenceline
Natural Gas Valve Station
Electrical Switching Station
BVWSD Well Field
HDD Entry/Exit Pits
OEHI CO2 EOR Project
EOR Processing Facility & Satellite Gathering Stations
Archaeological Area of Potential Effects
Historic Architectural Area of Potential Effects

N

0 1,000 2,000 FEET

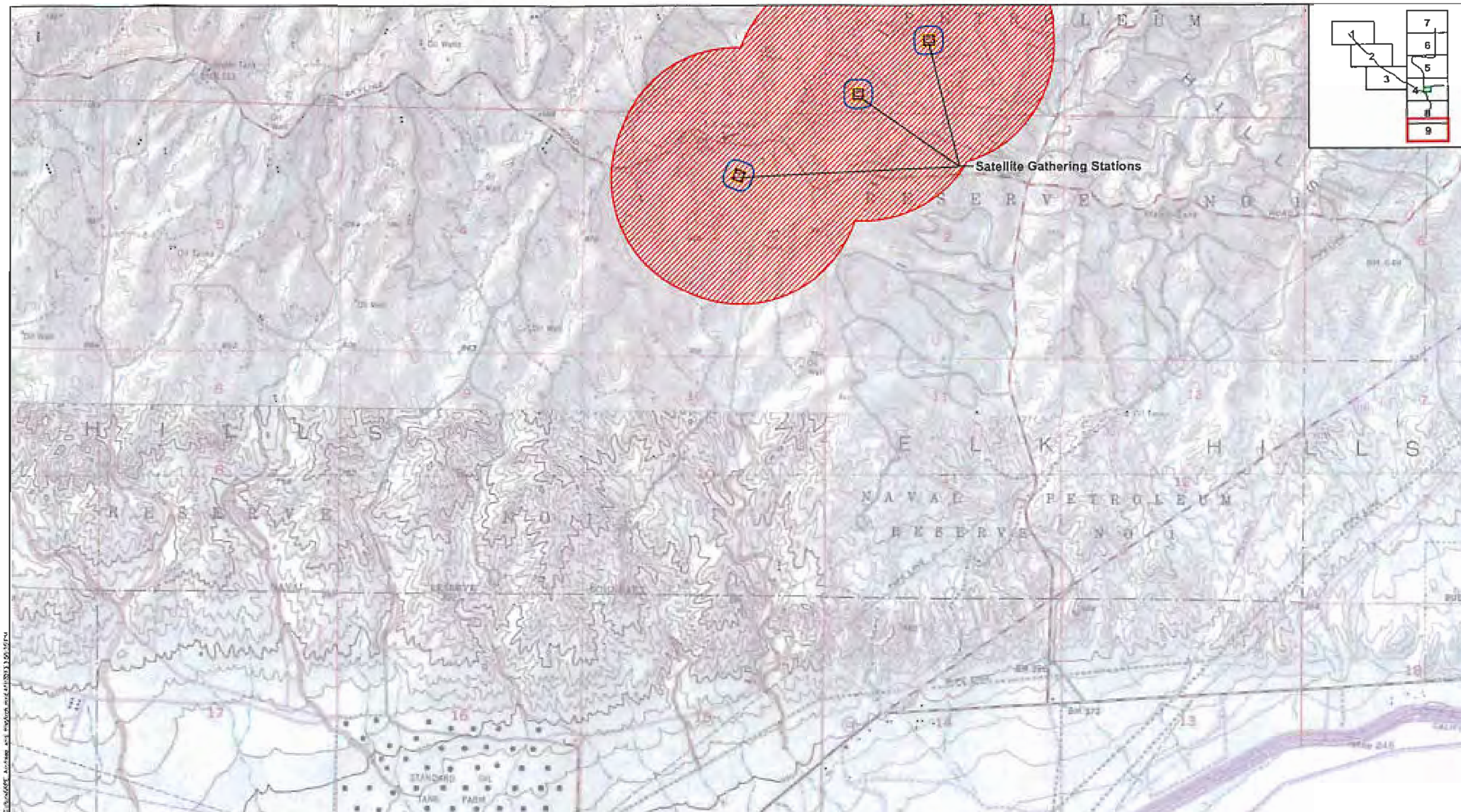
AREA OF POTENTIAL EFFECTS

April 2013
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 1 - SHEET 8



Project Site
Construction Staging Area
Rail Laydown Yard
Controlled Area Fenceline
Natural Gas Valve Station
Electrical Switching Station
BVWSD Well Field
HDD Entry/Exit Pits
OEHI CO2 EOR Project
EOR Processing Facility & Satellite Gathering Stations
Archaeological Area of Potential Effects
Historic Architectural Area of Potential Effects

AREA OF POTENTIAL EFFECTS

April 2013
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 1 - SHEET 9

Sources: USGS (30'x60' quads: 1x1 1963, Delano 1957) Copyright © 2011 National Geographic Society, i-cubed

NETL
NATIONAL ENERGY TECHNOLOGY LABORATORY
Albany, OR · Morgantown, WV · Pittsburgh, PA
U.S. DEPARTMENT OF ENERGY

May 8, 2012

Milford W. Donaldson
State Historic Preservation Officer
California State Department of Parks and Recreation
PO Box 942896
Sacramento, CA 94296-0001

Subject: Proposed Hydrogen Energy California Project in Kern County, California

Dear Mr. Donaldson:

The purpose of this letter is to inform you of the proposed Hydrogen Energy California Project (HECA or the Project) in Kern County, California; to initiate Section 106 consultation under the *National Historic Preservation Act of 1966* (NHPA); and to seek concurrence and input on the delineation of Area of Potential Effects (APE) for both archaeological and historic architectural resources (*See Attached Area Map and Area of Potential Effects Map*).

HECA is proposed by Hydrogen Energy California LLC. The Project is part of U.S. Department of Energy's (DOE) Clean Coal Power Initiative, a cost-shared collaboration between the federal government and private industry to increase investment in low-emission coal technology by demonstrating advanced coal-based power generation technologies at commercial scale. The HECA is supported in part by DOE with a $408 million grant in a cost-shared arrangement. Total project costs are estimated to be approximately $4 billion. DOE has determined that the proposed Project is a federal undertaking as defined in 36 Code of Federal Regulations § 800.16(y).

The Project consists of an Integrated Gasification Combined Cycle power facility, with an integrated manufacturing complex which will produce low-carbon nitrogen-based products, such as fertilizer. The Project will utilize a blend of coal and petroleum coke as a feedstock in order to produce hydrogen-rich syngas fuel through a gasification process. This fuel will be used in a combustion turbine to produce a nominal 300 megawatts (MW) of electricity and allow the manufacture of low-carbon nitrogen-based products such as fertilizers. The production of electricity, low-carbon nitrogen-based products, and carbon dioxide (CO_2) for enhanced oil recovery (EOR) enables the operational flexibilities to meet market demands. Because it produces several products, HECA is sometimes referred to as a "polygeneration" project.

The electricity and other products produced by the Project will have a smaller carbon footprint than similar products produced from traditional fossil fuel sources through a conventional combustion process. This is accomplished primarily by capturing approximately 90 percent of the CO_2 from the gasification process. Captured CO_2 will be transported (via a pipeline) for use in EOR, which results in sequestration of the CO_2 in secure geologic formations, at the nearby Elk Hills Oil Field (EHOF). EHOF is owned and operated by Occidental of Elk Hills, Inc. (OEHI), which will obtain necessary permits for the EOR operations.

3610 Collins Ferry Road, P.O. Box 880, Morgantown, WV 26507
fred.pozzuto@netl.doe.gov • Voice (304) 285-5219 • Fax (304) 285-4403 • www.netl.doe.gov

The 453-acre Project site is located approximately 7-miles west of the outermost edge of the city of Bakersfield and 1.5-miles northwest of the unincorporated community of Tupman in western Kern County, California. The majority of the Project site has been repetitively tilled and is presently used for agricultural purposes, including cultivation of cotton, alfalfa, and onions. Temporary construction activities, including equipment storage, construction laydown, parking and offices, will be located on the Project site and within an adjacent 91-acre Construction Laydown Area.

The Project also includes the following off-site facilities:

- Rail Spur – A new rail spur will be constructed to the Project site in order to facilitate feedstock and equipment delivery, as well as product and by-product off-take. The rail spur will extend approximately 4.6-miles from the existing San Joaquin Valley Railroad to the Project site.
- Electrical Transmission Line – An electrical transmission line will interconnect the Project to a future Pacific Gas & Electric (PG&E) switching station to the east of the Project site (adjacent to the existing Midway-Wheeler Ridge transmission lines). The electrical transmission line is approximately 3.5-miles long, of which 1.5-miles will be located within the Project site.
- Natural Gas Supply Line – A natural gas interconnection will be made with an existing PG&E natural gas pipeline that is located north of the Project site. The natural gas pipeline is approximately 11.1-miles in length.
- Water Supply Pipelines – The Project will utilize brackish groundwater supplied from the Buena Vista Water Storage District located northwest of the Project site. The raw water supply pipeline will be approximately 14.4-miles in length. Potable water for construction, drinking, and sanitary use will be delivered from a new West Kern Water District potable water production site approximately 1.3-miles east of the Project site.
- CO_2 Pipeline – The CO_2 pipeline will transfer the CO_2 captured during gasification from the Project site (plant) south to the EHOF for EOR and sequestration (storage). The CO_2 pipeline is approximately 3.4-miles in length.

For the purposes of initiating informal consultation with the Office of Historic Preservation on the delineation of the APE, DOE is defining the APE for archaeological resources as all areas where ground-disturbing activities will occur in relation to the Project. More specifically, 200-feet from the Project site and Construction Laydown Area, and 50-feet from the right of way of all Project linears. The APE for historic architecture is defined as 0.5-miles around the Project site and 0.5-miles from the electric transmission and rail spur right of ways to account for potential indirect effects. Attached are copies of the proposed APEs for both archaeological and historic architectural resources.[1] The APEs for archaeological and historic architectural resources are consistent with the requirements of the California Energy Commission (CEC), which has exclusive authority for licensing thermal power plants in California with a generating capacity of 50-MW or more.

[1] Note that the identified APEs may be over-inclusive in the sense that they include the sites of the EOR to be undertaken by OEHI, which is not a recipient of federal funding in connection with its EOR activities.

DOE seeks to initiate informal Section 106 consultation under the NHPA for the undertaking and seek concurrence on the delineation of APEs for both archaeological and historic architectural resources. A joint CEC/DOE environmental impact statement (EIS) is currently being prepared for the project, and the draft version will be made available to you at a later date where you may again respond to any specific concerns you may have. DOE will include correspondence with your office in an appendix to the EIS. HECA's full application to the CEC can also be viewed at: http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/index.html#applicant

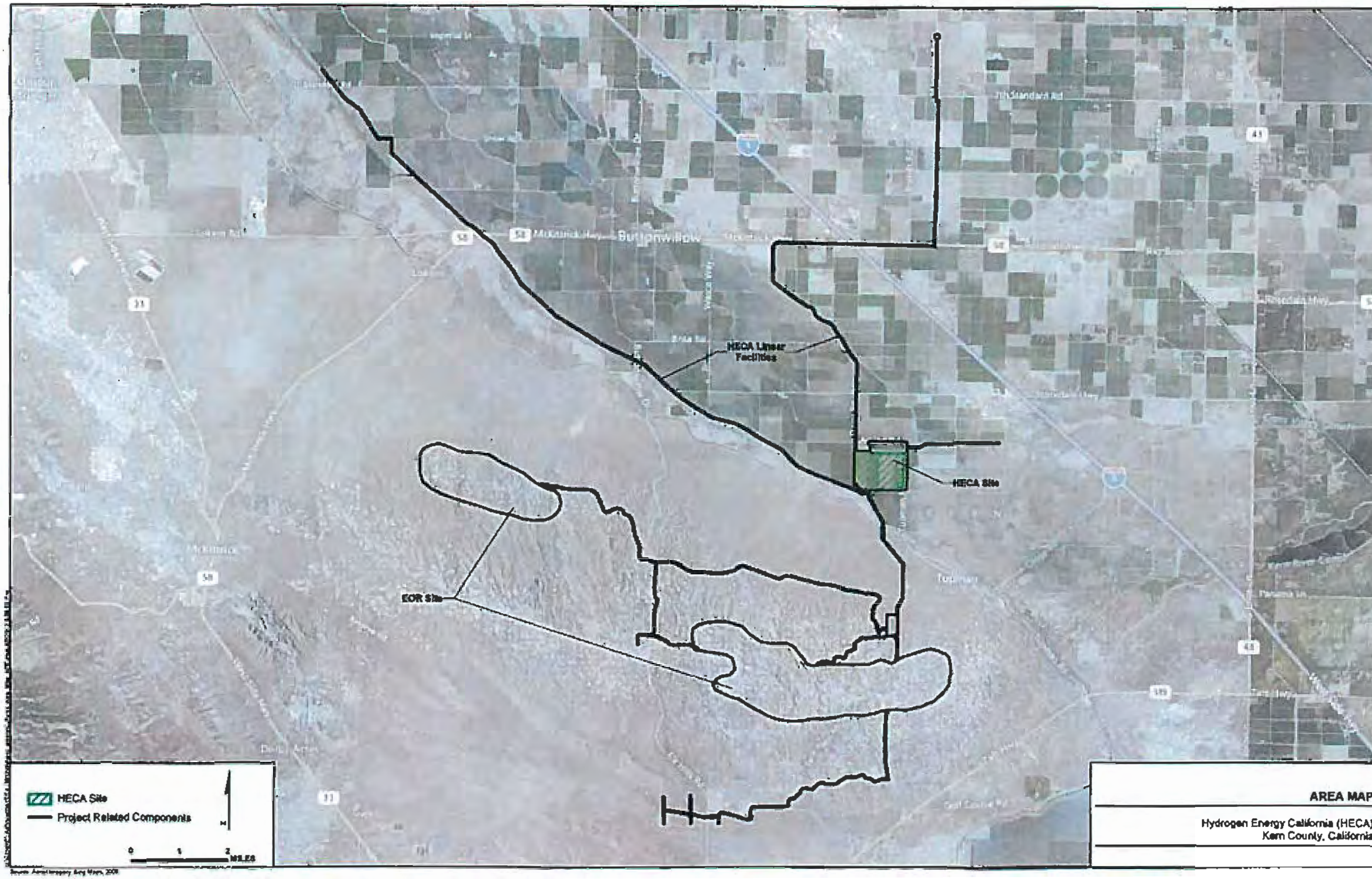
For any overall environmental project questions please contact me at 304-285-5219. Should you have any technical questions please contact the Office of National Environmental Policy Act (NEPA) contractor, Mr. Dale Shileikis at 415-243-3708, or by email @ dale.shileikis@urs.com.

Sincerely,

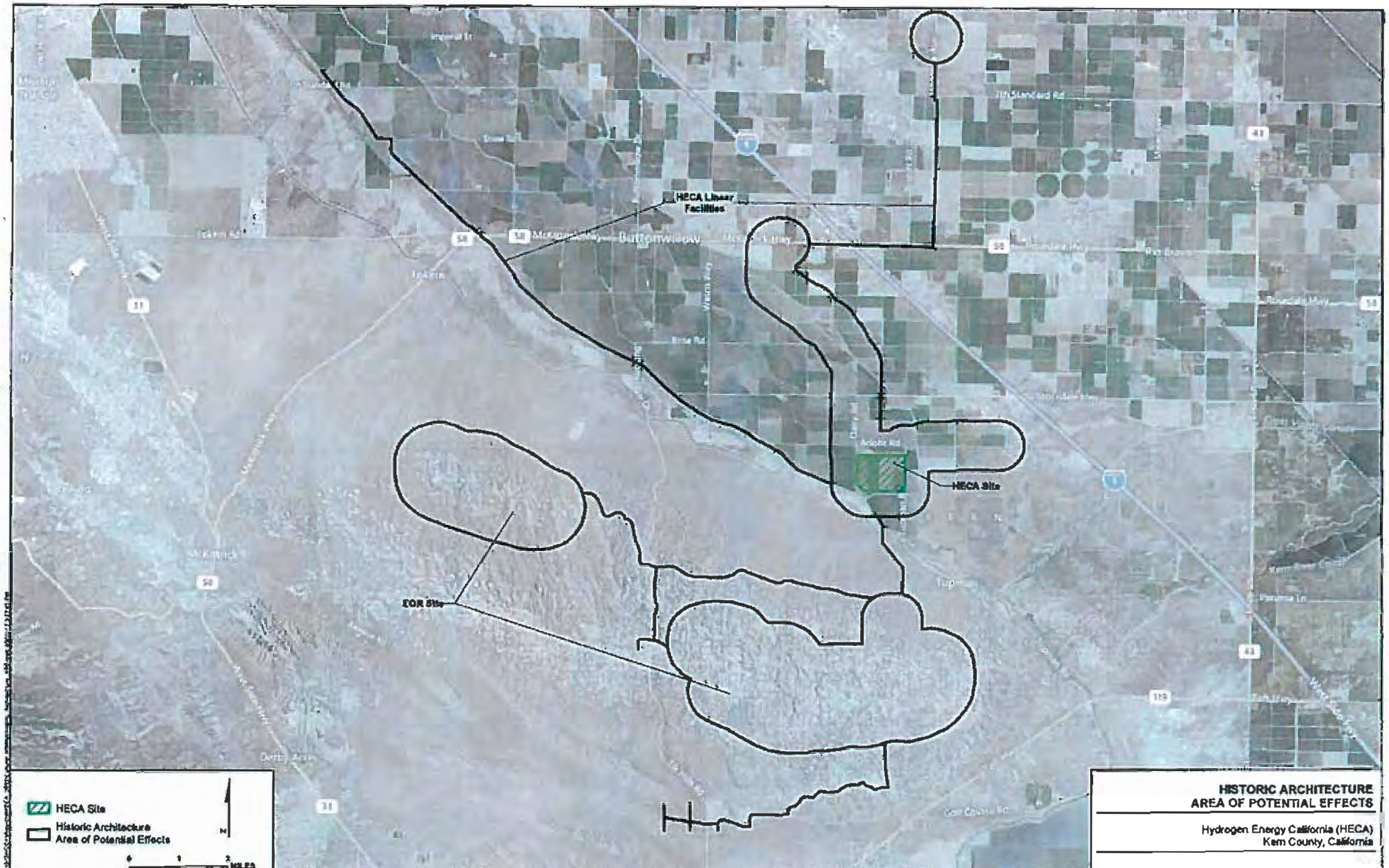
Fred Pozzuto
Environmental Manager / NEPA Compliance Officer

Enclosures:

cc:
M. Mascaro - HECA-SCS Energy
D. Shileikis - URS

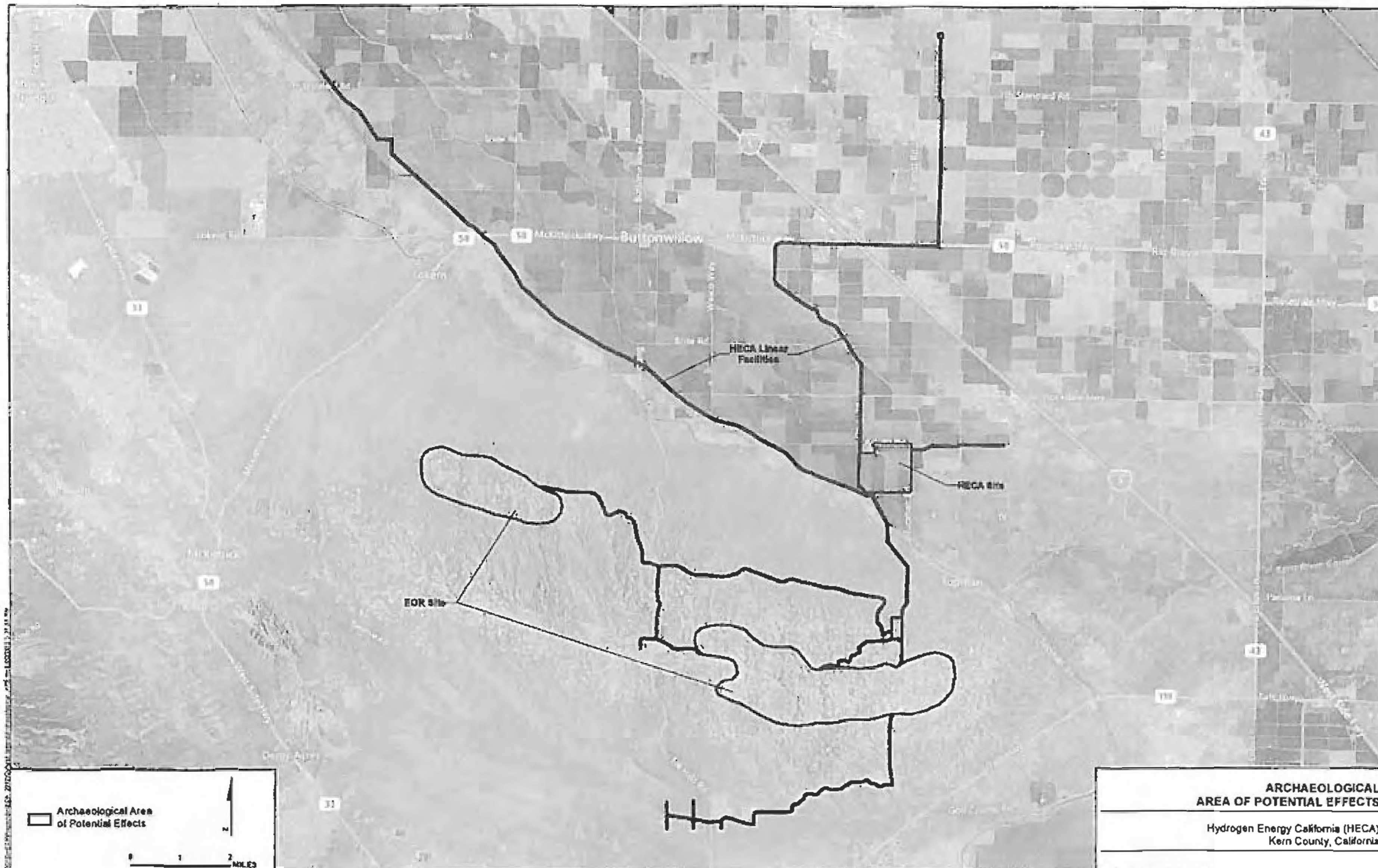


HECA Linear Facilities
HECA Site
EOR Site
Buttonwillow
HECA Site
Project Related Components
0
1
2
MILES
N
AREA MAP
Hydrogen Energy California (HECA)
Kern County, California



HISTORIC ARCHITECTURE
AREA OF POTENTIAL EFFECTS

Hydrogen Energy California (HECA)
Kern County, California


HECA Linear Facilities
HECA Site
EOR Site
Buttonwillow
Archaeological Area of Potential Effects
MILES
ARCHAEOLOGICAL AREA OF POTENTIAL EFFECTS
Hydrogen Energy California (HECA)
Kern County, California

STATE OF CALIFORNIA – THE NATURAL RESOURCES AGENCY

TN65607

EDMUND G. BROWN, JR., *Governor*

OFFICE OF HISTORIC PRESERVATION
DEPARTMENT OF PARKS AND RECREATION
1725 23rd Street, Suite 100
SACRAMENTO, CA 95816-7100
(916) 445-7000 Fax: (916) 445-7053
calshpo@parks.ca.gov
www.ohp.parks.ca.gov

DOCKET	
08-AFC-8A	
DATE	MAY 25 2012
RECD	JUN 05 2012

May 25, 2012

Reply in Reference To: DOE120514A

Fred Pozzuto
Environmental Manager
US Dept. of Energy
National Energy Technology Laboratory
3610 Collins Ferry Road
PO Box 880
Morgantown, WV 26507-0880

Re: Section 106 Consultation for Hydrogen Energy California Project, Kern County, CA

Dear Mr. Pozzuto:

Thank you for initiating consultation regarding the Department of Energy's (DOE) efforts to comply with Section 106 of the National Historic Preservation Act of 1966 (16 U.S.C. 470f), as amended, and its implementing regulation found at 36 CFR Part 800.

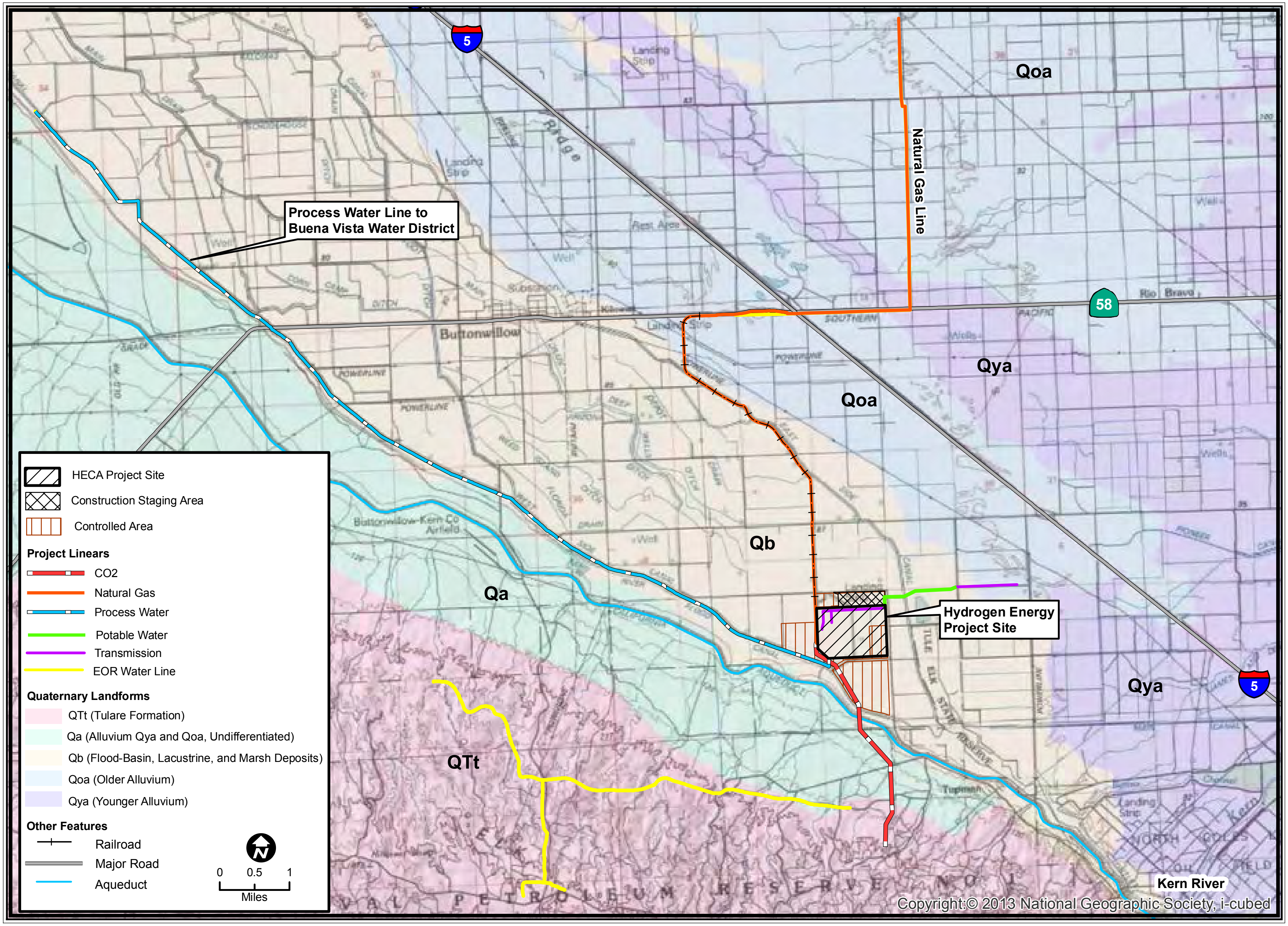
The DOE is proposing to construct an Integrated Gasification Combined Cycle power facility in Kern County and are requesting my concurrence and comments with their Area of Potential Effect determination for historic architecture and archeology. Due to a lack of sufficient information I am presently unable to concur with these determinations. I look forward to reviewing additional information on this undertaking as it becomes available.

Thank you for seeking my comments and considering historic properties as part of your project planning. I look forward to continuing this consultation with the DOE. If you have any questions or concerns, please contact Ed Carroll of my staff at (916) 445-7006 or ecarroll@parks.ca.gov.

Sincerely,

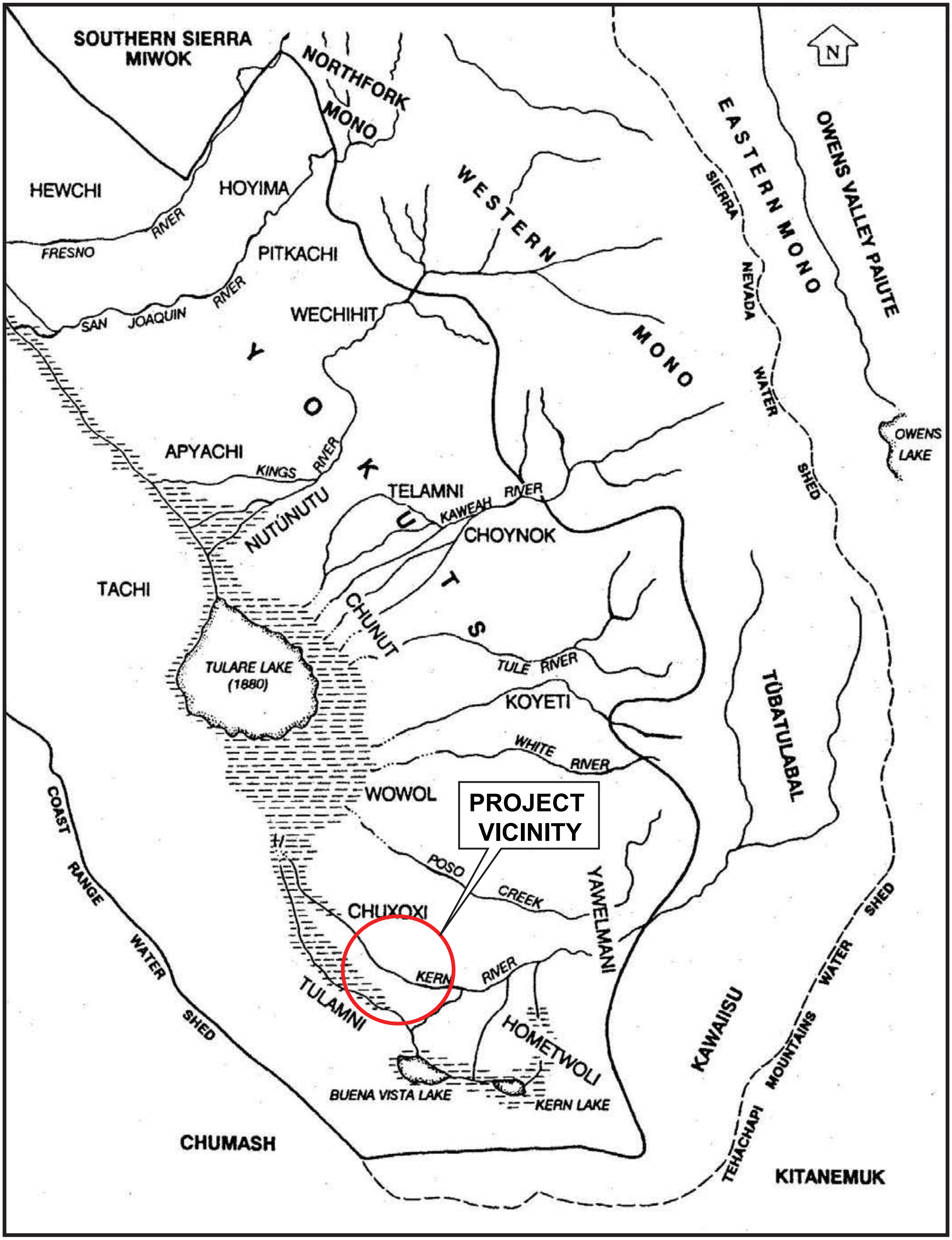
Jenan Saunders
(for) Milford Wayne Donaldson, FAIA
State Historic Preservation Officer

CULTURAL RESOURCES - FIGURE 1
Hydrogen Energy California - Geological Formations



CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING DIVISION
SOURCE: URS, USGS, OpernStreetMap - January 2013.

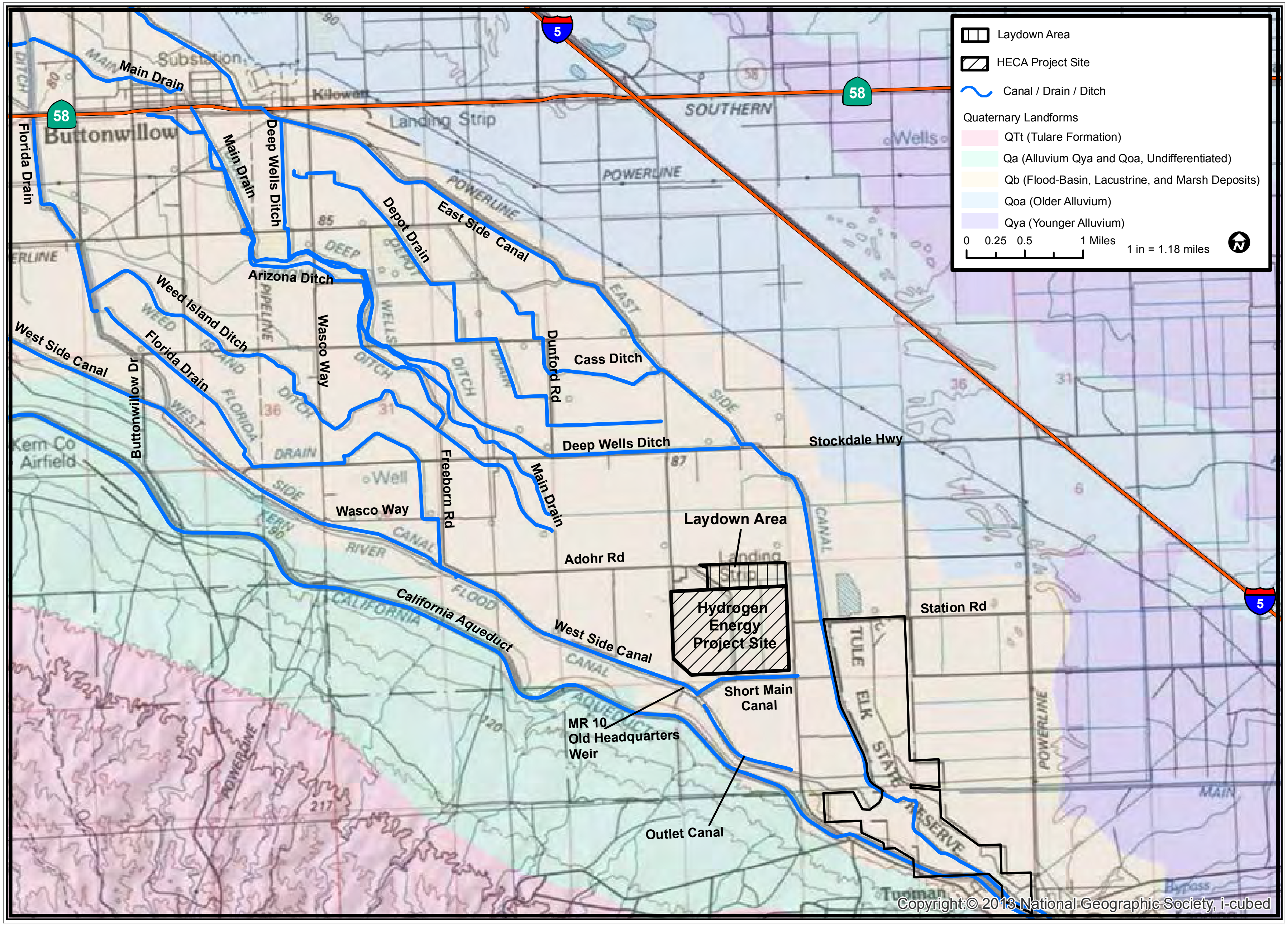
CULTURAL RESOURCES - FIGURE 2
Hydrogen Energy California - Ethnograpic Territories



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: URS 2012a

CULTURAL RESOURCES - FIGURE 3

Hydrogen Energy California - Canals, Drains and Ditches

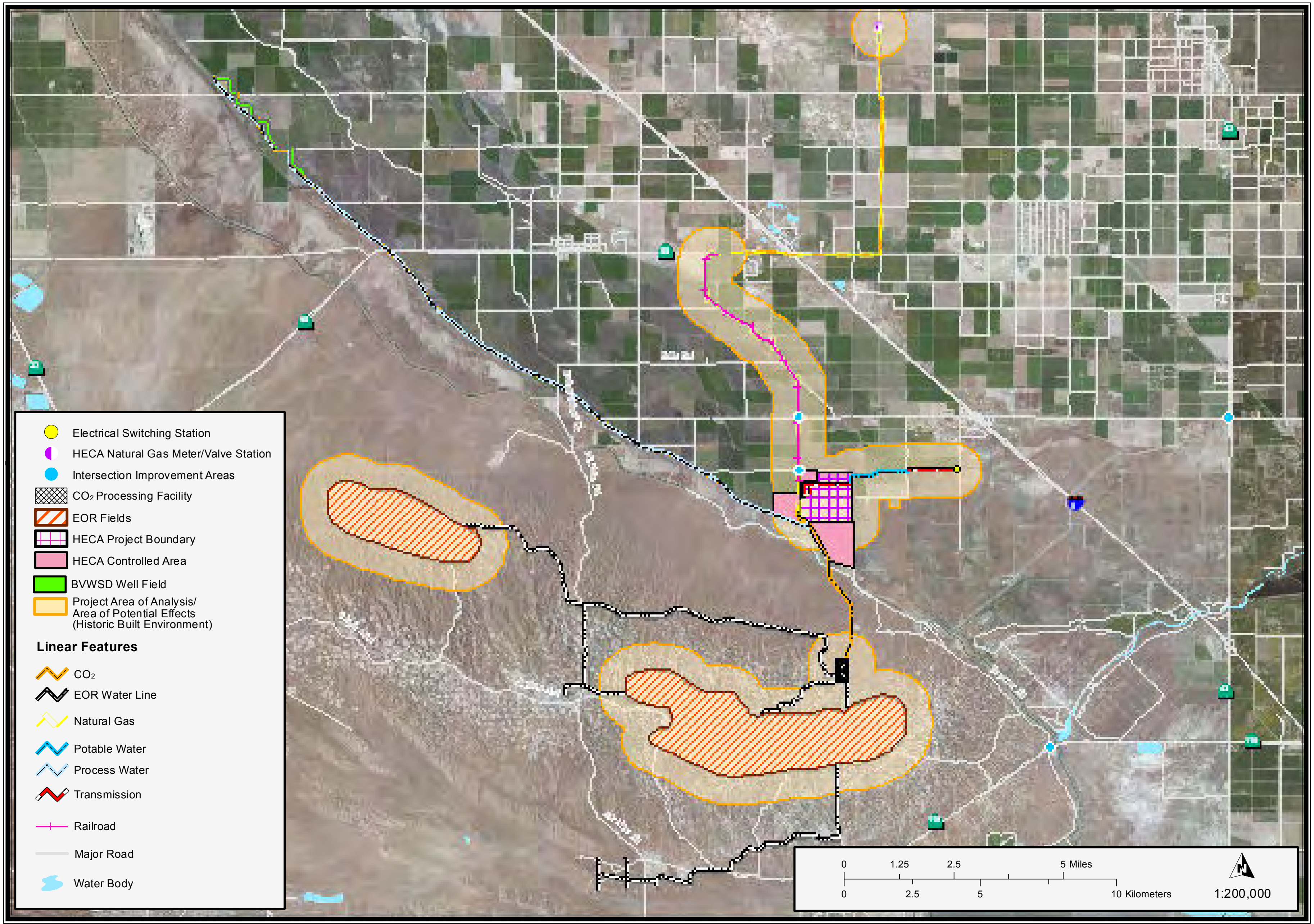


CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING DIVISION

SOURCE: URS, Kern County, USGS

CULTURAL RESOURCES

CULTURAL RESOURCES - FIGURE 4
Hydrogen Energy California (HECA) - Overview of Proposed Project

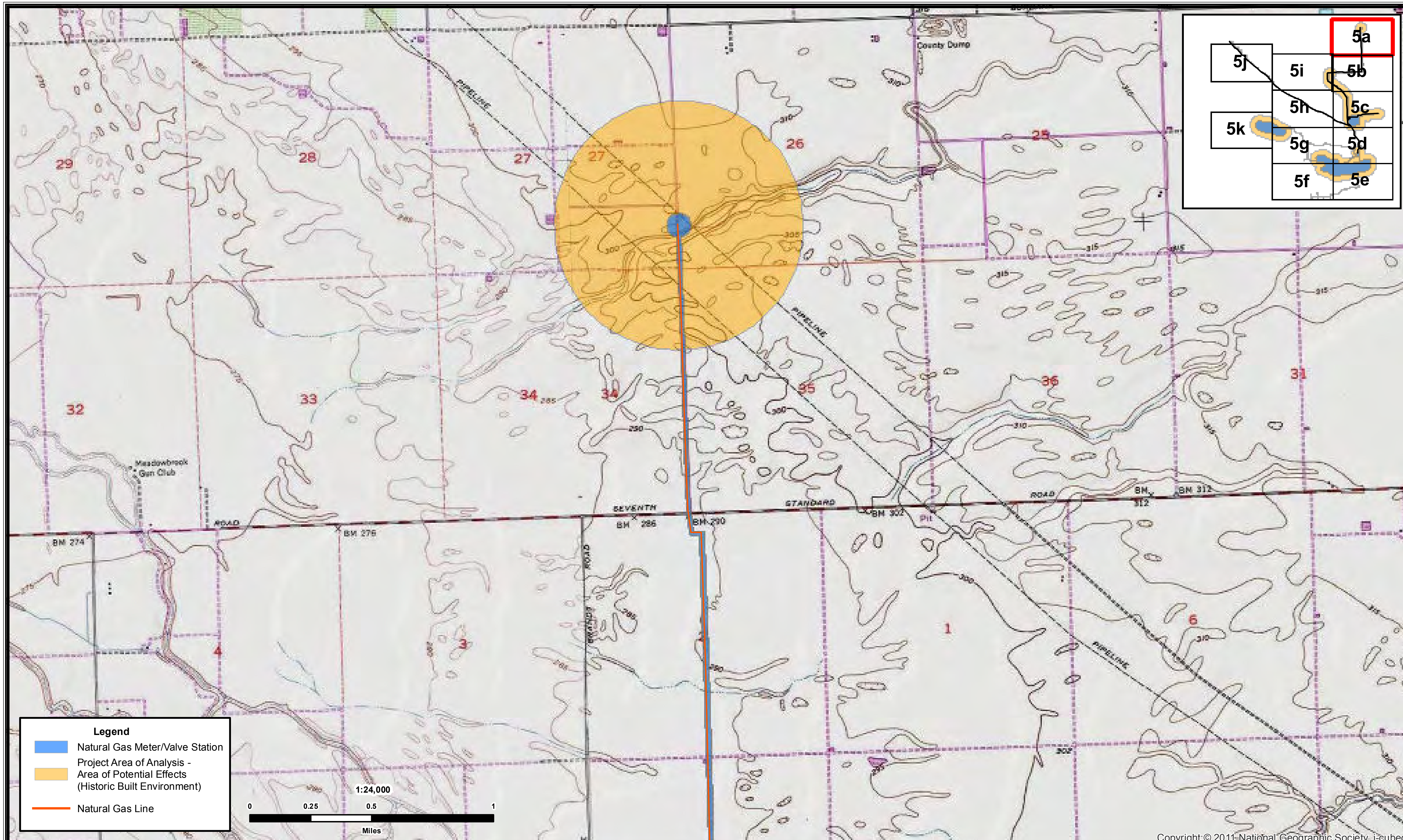


CULTURAL RESOURCES

CALIFORNIA ENERGY COMMISSION, SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: URS, TeleAtlas Street 2010, and Bing Aerial.

CULTURAL RESOURCES - FIGURE 5a

Hydrogen Energy California - Project Area of Analysis / Area of Potential Effects



CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING DIVISION

SOURCE: URS & USGS

Note: All project components shown outside the limits of the Project Area of Analysis/Area of Potential Effects (Historic Built Environment) are within the Project Area of Analysis/Area of Potential Effects (Archaeology)

CULTURAL RESOURCES - FIGURE 5b

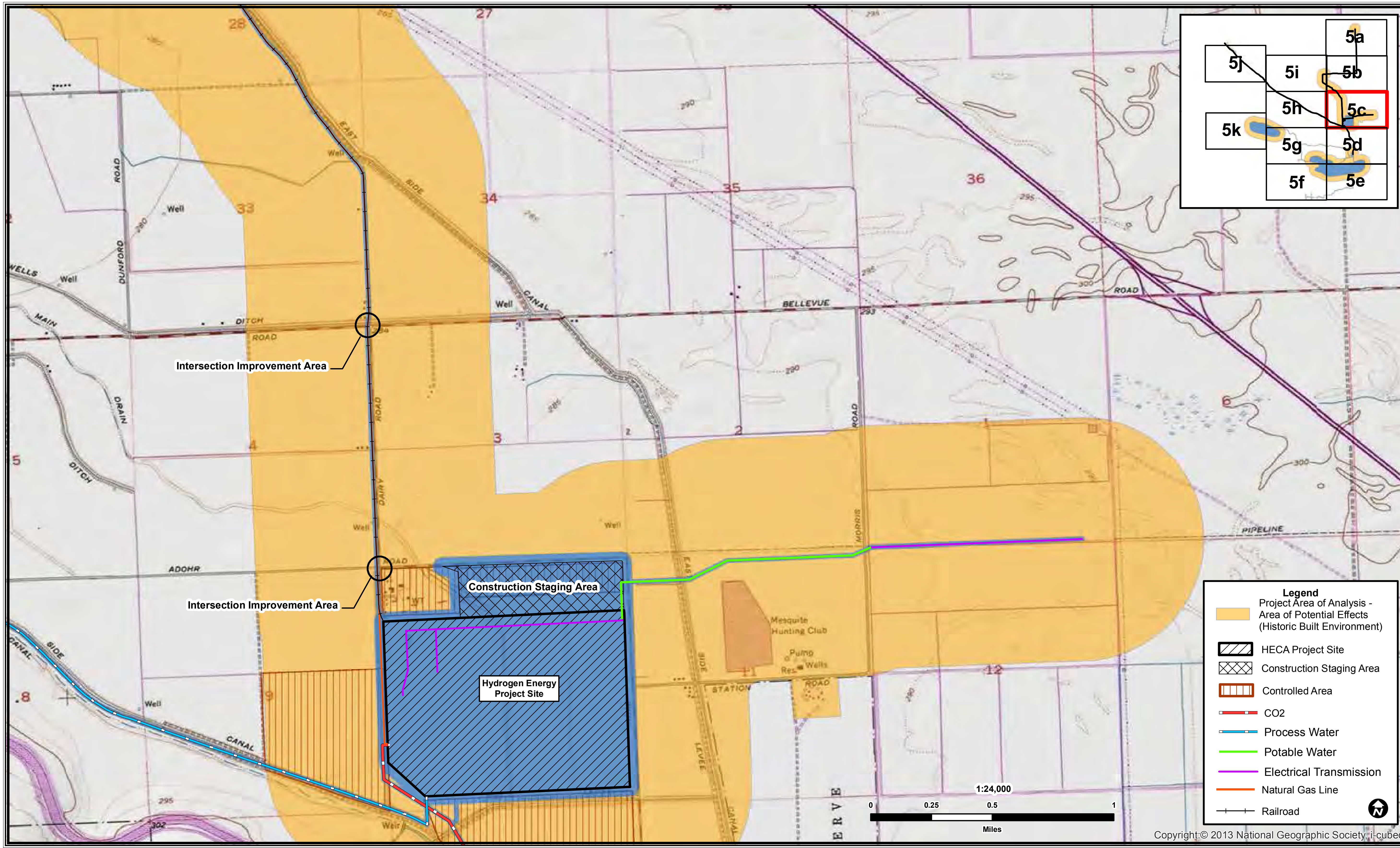
Hydrogen Energy California - Project Area of Analysis / Area of Potential Effects

CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING DIVISION

SOURCE: URS & USGS

Note: All project components shown outside the limits of the Project Area of Analysis/Area of Potential Effects (Historic Built Environment) are within the Project Area of Analysis/Area of Potential Effects (Archaeology)

CULTURAL RESOURCES - FIGURE 5c
Hydrogen Energy California - Project Area of Analysis / Area of Potential Effects

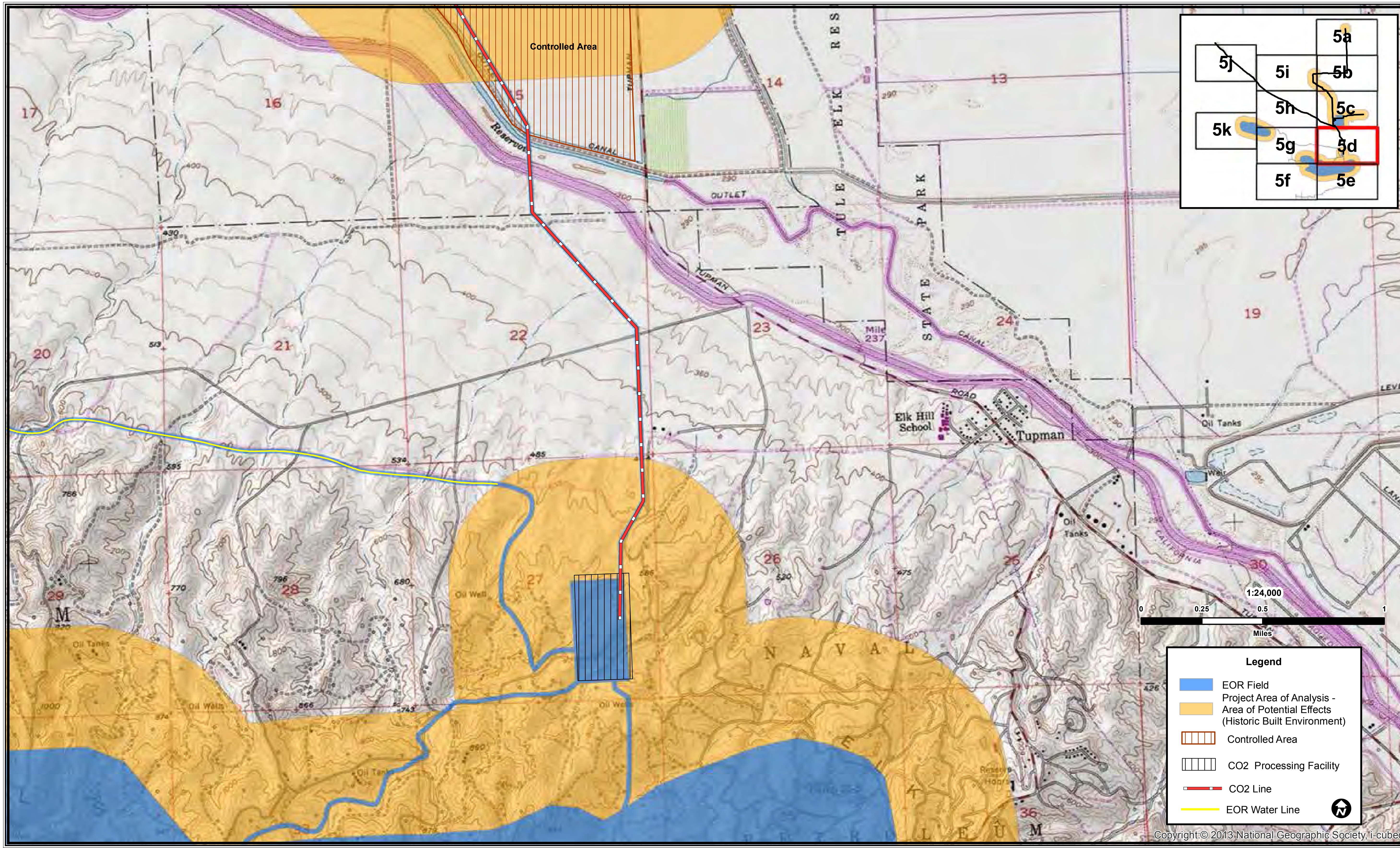


CULTURAL RESOURCES

CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING DIVISION
SOURCE: URS & USGS
Note: All project components shown outside the limits of the Project Area of Analysis/Area of Potential Effects (Historic Built Environment) are within the Project Area of Analysis/Area of Potential Effects (Archaeology)

CULTURAL RESOURCES - FIGURE 5d

Hydrogen Energy California - Project Area of Analysis / Area of Potential Effects



CULTURAL RESOURCES

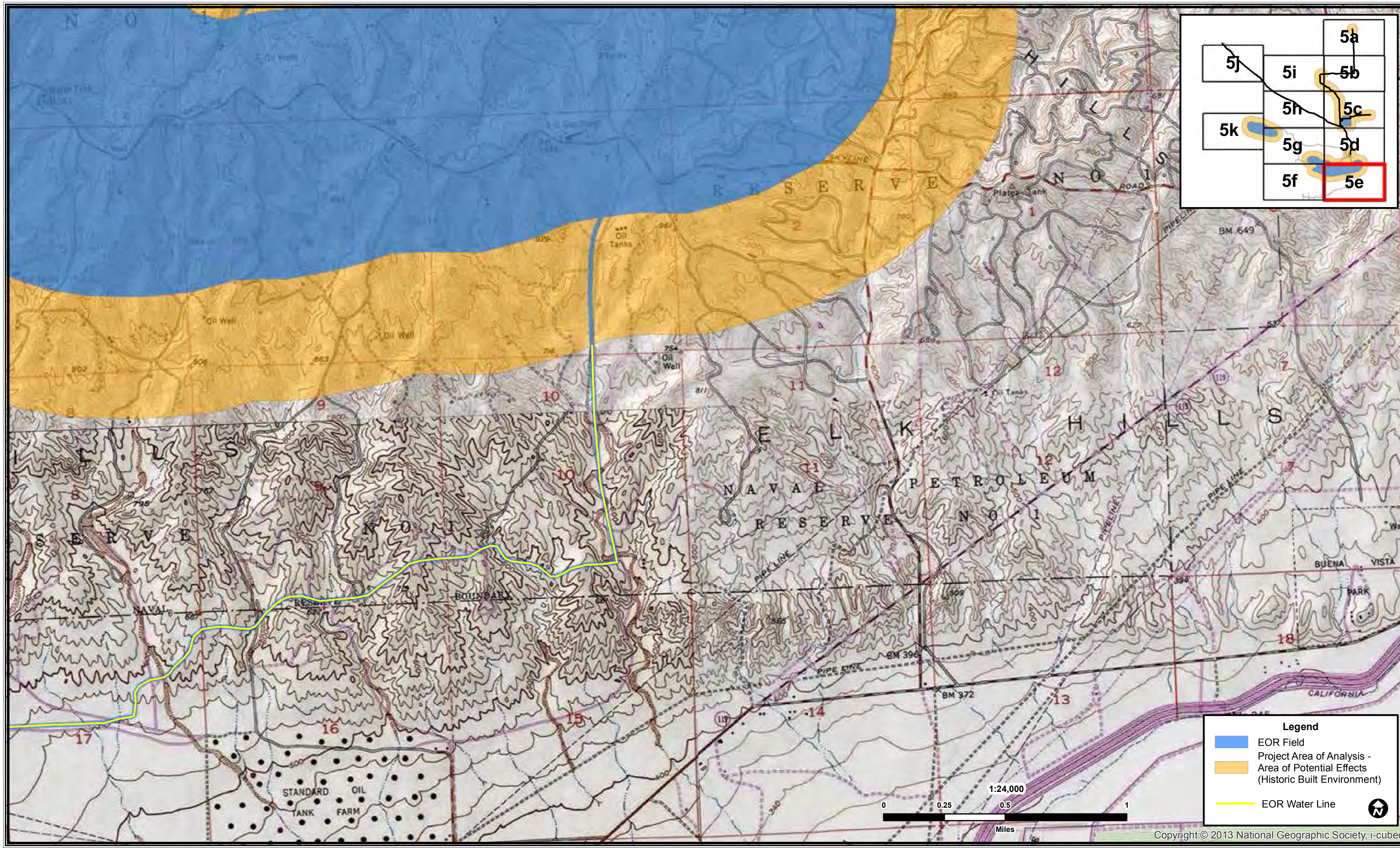
CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING DIVISION

SOURCE: URS & USGS

Note: All project components shown outside the limits of the Project Area of Analysis/Area of Potential Effects (Historic Built Environment) are within the Project Area of Analysis/Area of Potential Effects (Archaeology)

CULTURAL RESOURCES - FIGURE 5e

Hydrogen Energy California - Project Area of Analysis / Area of Potential Effects



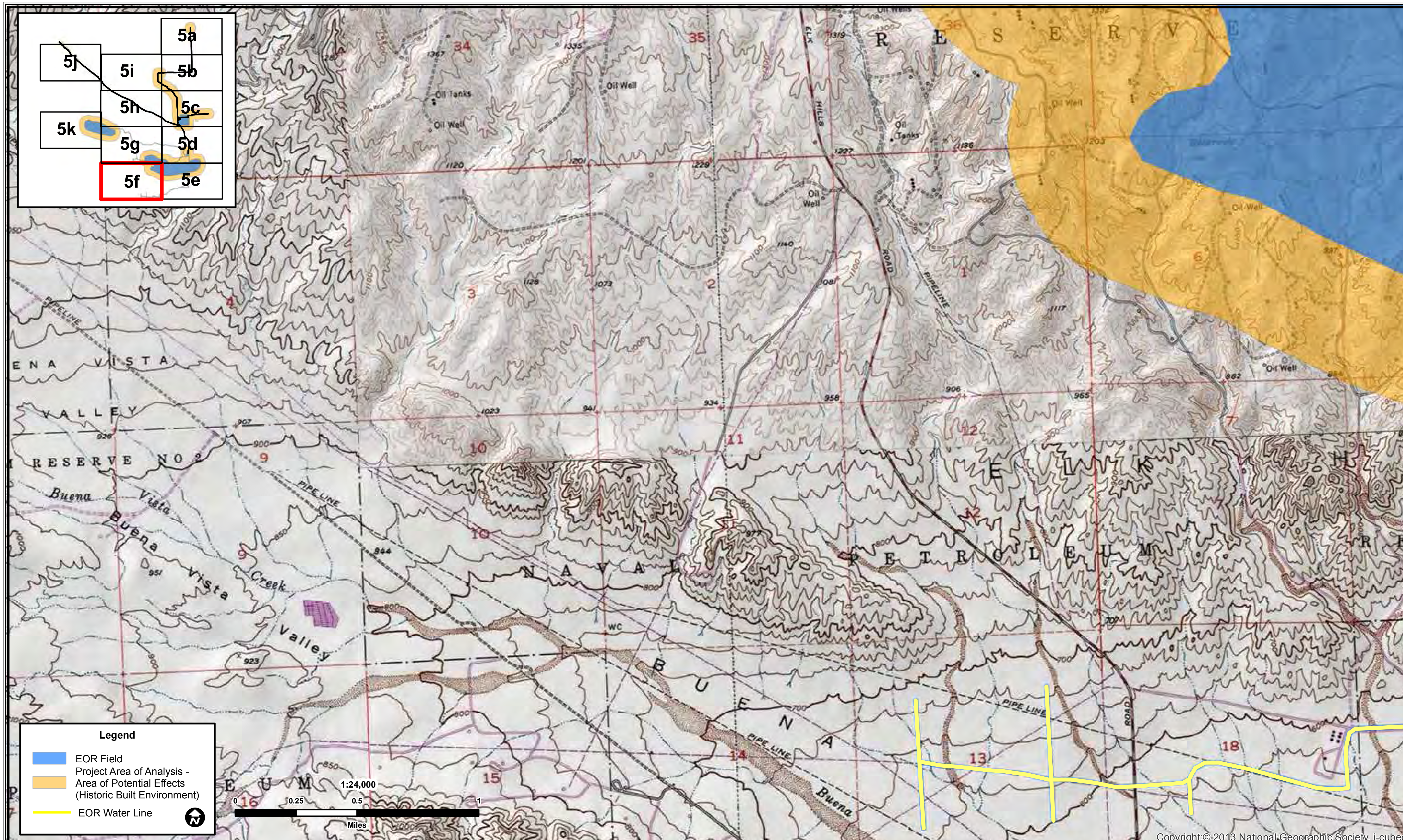
CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING DIVISION

SOURCE: URS & USGS

Note: All project components shown outside the limits of the Project Area of Analysis/Area of Potential Effects (Historic Built Environment) are within the Project Area of Analysis/Area of Potential Effects (Archaeology)

CULTURAL RESOURCES - FIGURE 5f

Hydrogen Energy California - Project Area of Analysis / Area of Potential Effects



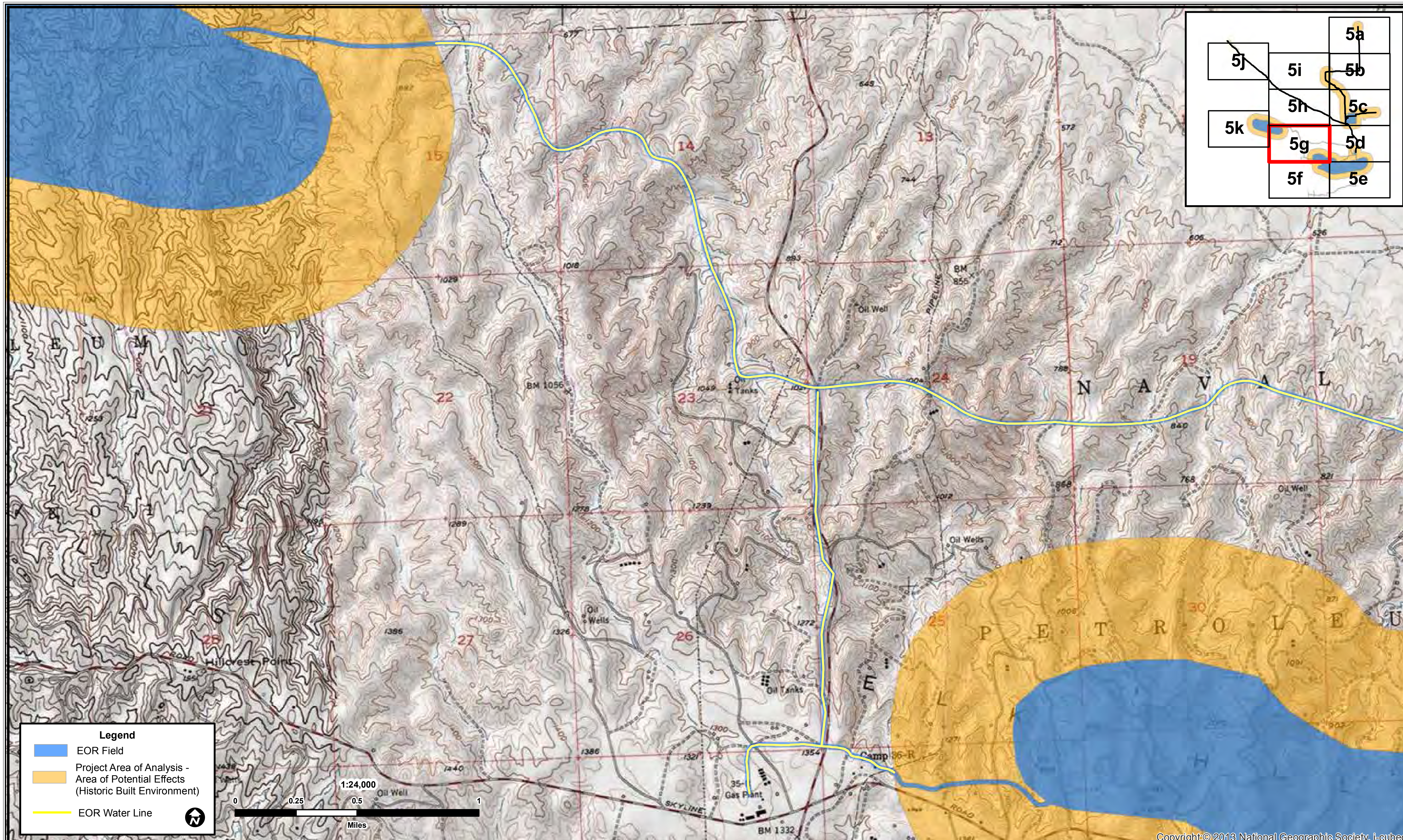
CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING DIVISION

SOURCE: URS & USGS

Note: All project components shown outside the limits of the Project Area of Analysis/Area of Potential Effects (Historic Built Environment) are within the Project Area of Analysis/Area of Potential Effects (Archaeology)

CULTURAL RESOURCES - FIGURE 5g

Hydrogen Energy California - Project Area of Analysis / Area of Potential Effects



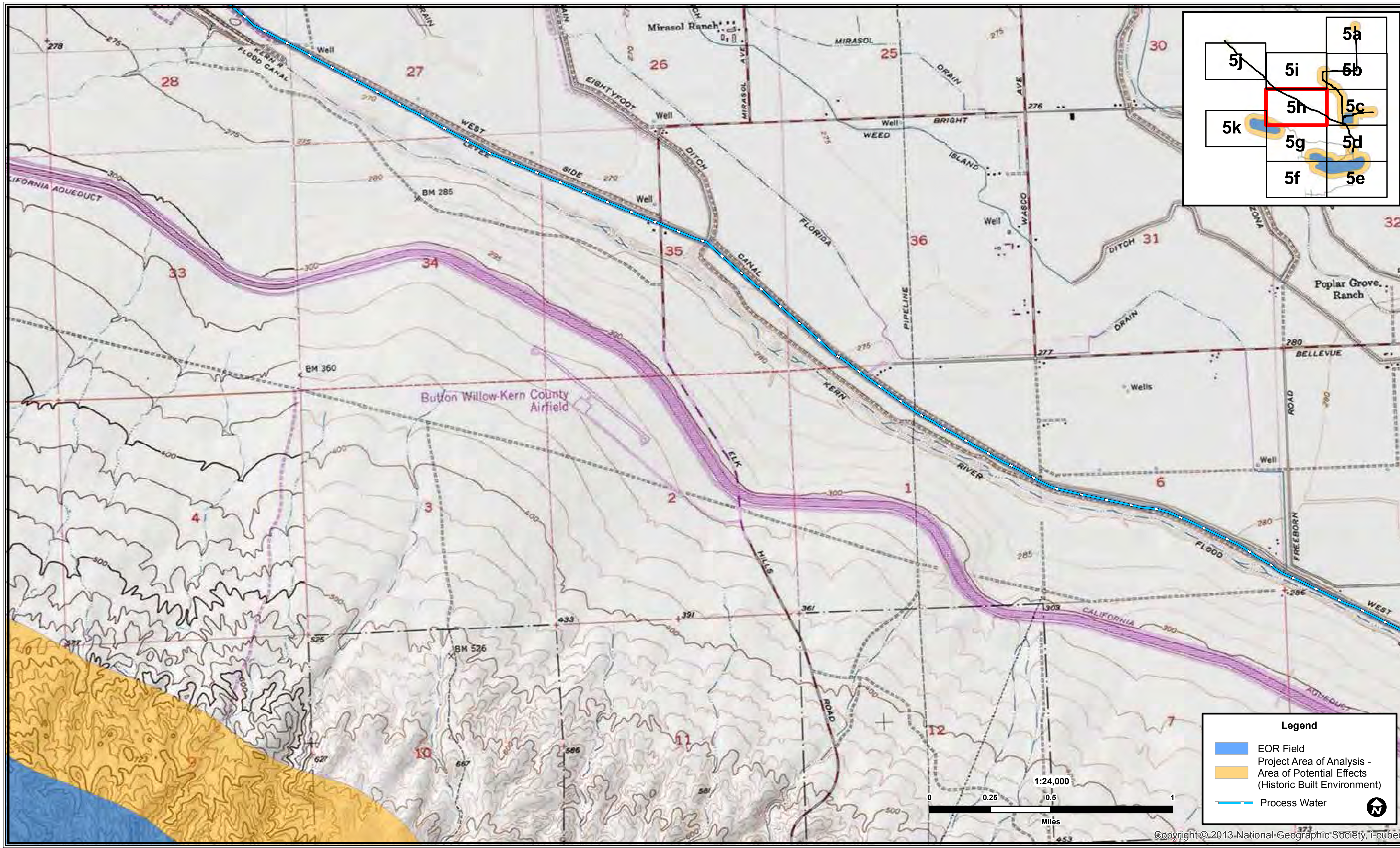
CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING DIVISION

SOURCE: URS & USGS

Note: All project components shown outside the limits of the Project Area of Analysis/Area of Potential Effects (Historic Built Environment) are within the Project Area of Analysis/Area of Potential Effects (Archaeology)

CULTURAL RESOURCES - FIGURE 5h

Hydrogen Energy California - Project Area of Analysis / Area of Potential Effects



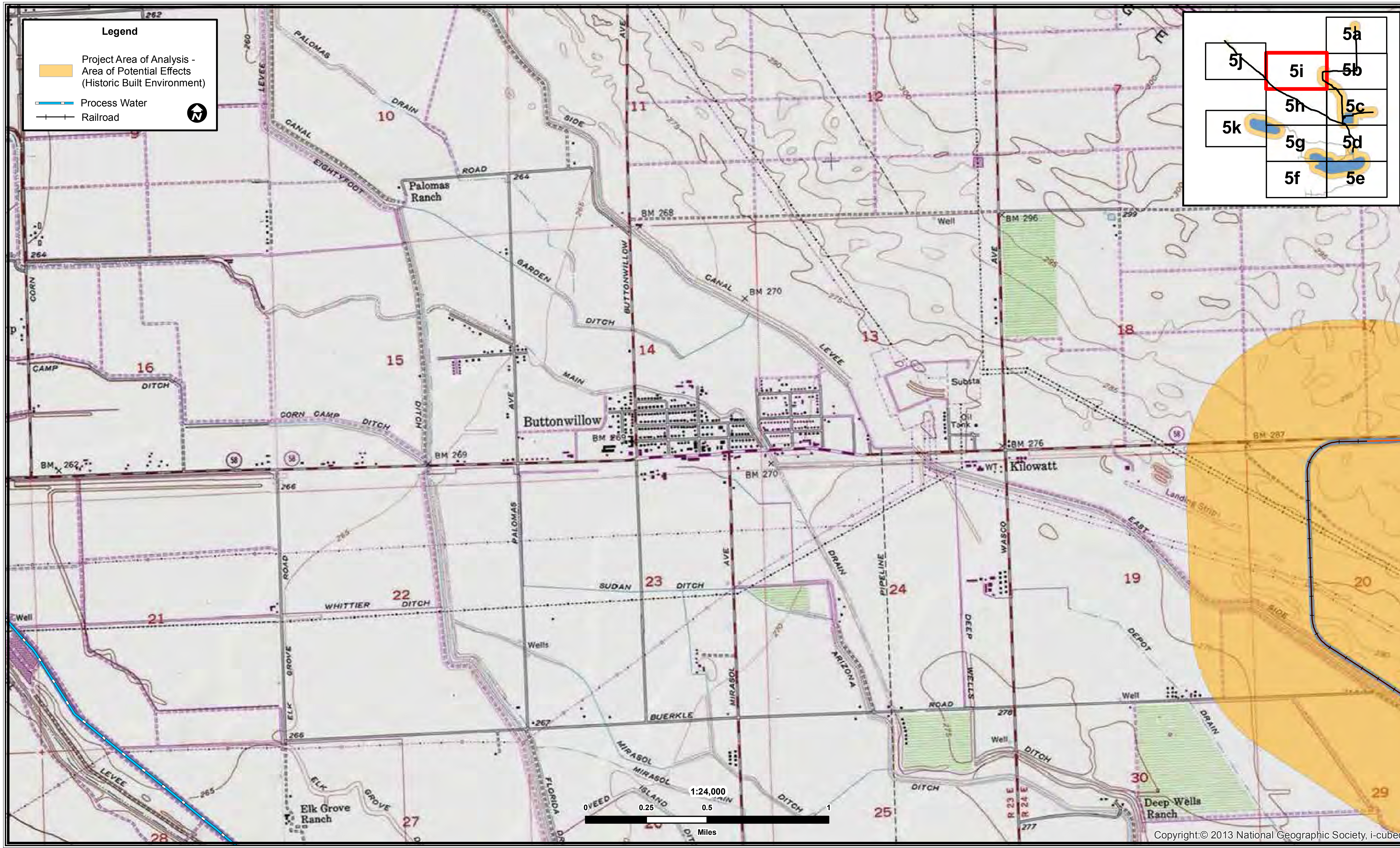
CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING DIVISION

SOURCE: URS & USGS

Note: All project components shown outside the limits of the Project Area of Analysis/Area of Potential Effects (Historic Built Environment) are within the Project Area of Analysis/Area of Potential Effects (Archaeology)

CULTURAL RESOURCES - FIGURE 5i

Hydrogen Energy California - Project Area of Analysis / Area of Potential Effects



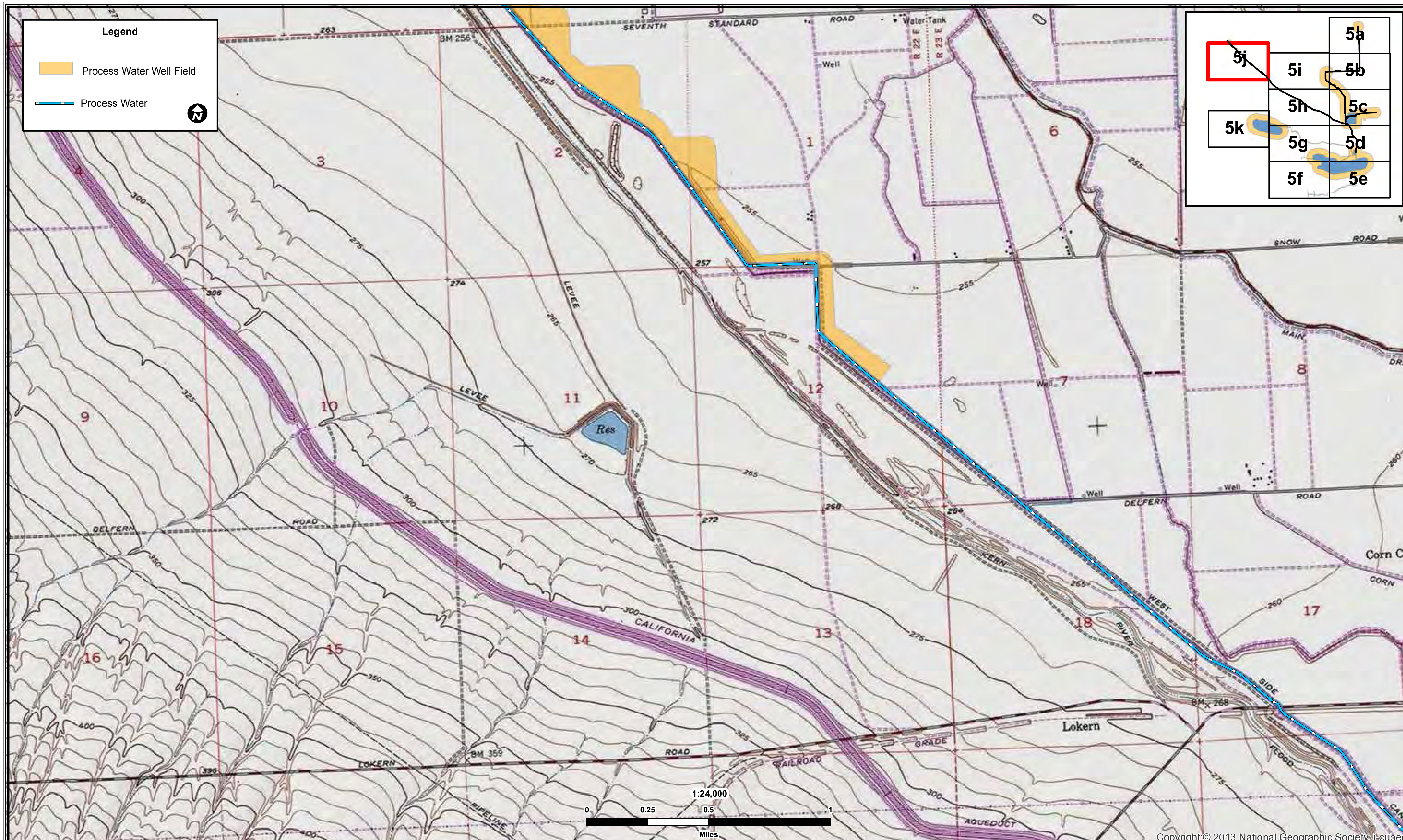
CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING DIVISION

SOURCE: URS & USGS

Note: All project components shown outside the limits of the Project Area of Analysis/Area of Potential Effects (Historic Built Environment) are within the Project Area of Analysis/Area of Potential Effects (Archaeology)

CULTURAL RESOURCES - FIGURE 5j

Hydrogen Energy California - Project Area of Analysis / Area of Potential Effects



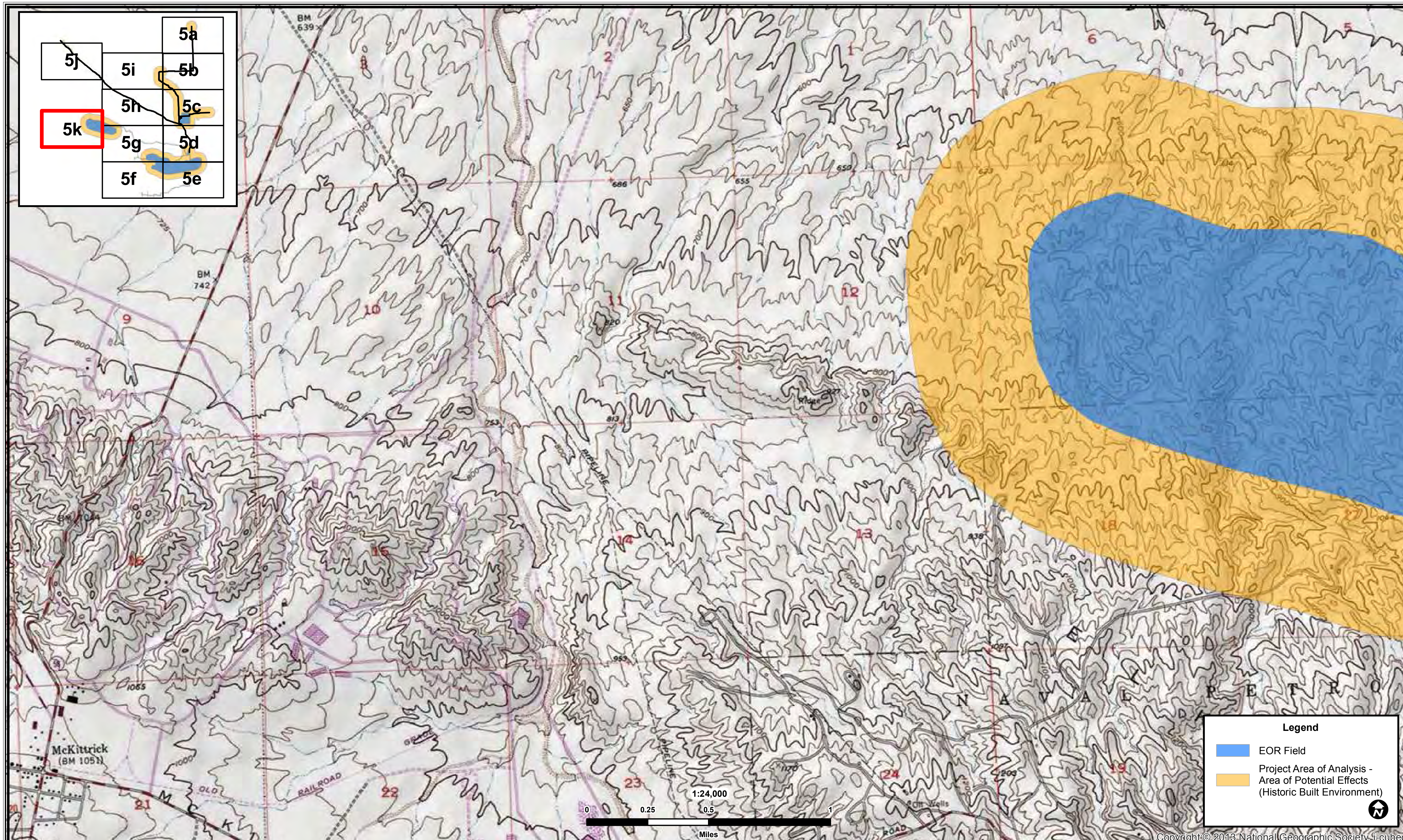
CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING DIVISION

SOURCE: URS & USGS

Note: All project components shown outside the limits of the Project Area of Analysis/Area of Potential Effects (Historic Built Environment) are within the Project Area of Analysis/Area of Potential Effects (Archaeology)

CULTURAL RESOURCES - FIGURE 5k

Hydrogen Energy California - Project Area of Analysis / Area of Potential Effects



CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING DIVISION

SOURCE: URS & USGS

Note: All project components shown outside the limits of the Project Area of Analysis/Area of Potential Effects (Historic Built Environment) are within the Project Area of Analysis/Area of Potential Effects (Archaeology)

CULTURAL RESOURCES - FIGURE 6
Hydrogen Energy California

Quonset Hut

WPA-Era Drainage Headwalls on Dairy Road

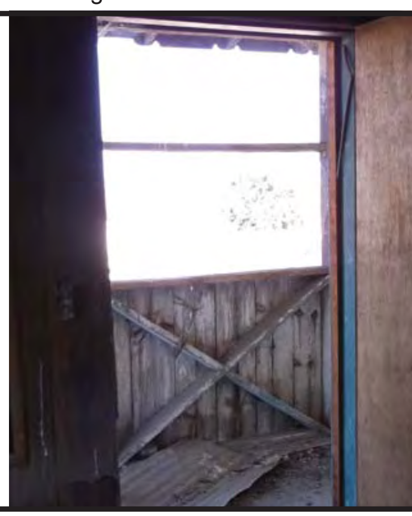
CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: Staff Photos

CULTURAL RESOURCES - FIGURE 7
Hydrogen Energy California

Adohr Farms/Palm Farms Main Residential Building (Building A)

Adohr Farms/Palm Farms Foreman's Home and Office (Building B)

Interior View of Building A Enclosed Porch with X-Design Porch Rail



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: Staff Photos

CULTURAL RESOURCES - FIGURE 8
Hydrogen Energy California

Adohr Farms/Palm Farms
Date Palm Allée at Building B

Adohr Farms/Palm Farms
Fan Palms Lining Perimeter on Three Sides

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: Staff Photos

Old Headquarters Weir

Old Headquarters Weir- View of Channel for Flashboards

SOURCE: Staff Photos

CULTURAL RESOURCES - FIGURE 10
Hydrogen Energy California - California Aqueduct at Elk Hills Road

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: Staff Photos

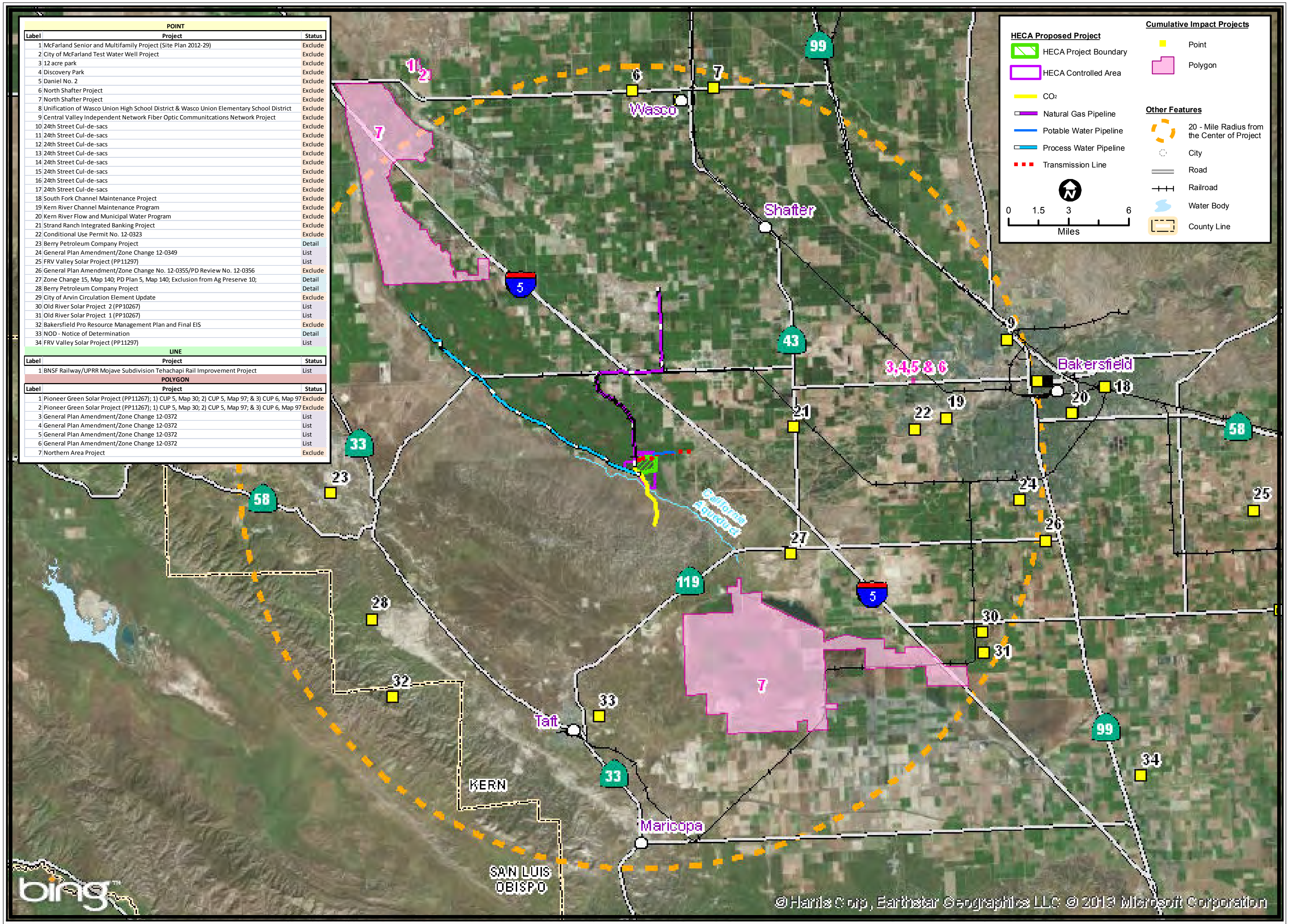
Naval Petroleum Reserve-1/Elk Hills Occidental, Inc.
View of WWII “Sea Bee” tank ditches

Naval Petroleum Reserve-1/Elk Hills Occidental, Inc.
Close up view of WWII “Sea Bee” tank ditch

SOURCE: Staff Photos

CULTURAL RESOURCES - FIGURE 12

Hydrogen Energy Project - Cumulative Impacts



POINT		
Label	Project	Status
1	McFarland Senior and Multifamily Project (Site Plan 2012-29)	Exclude
2	City of McFarland Test Water Well Project	Exclude
3	12 acre park	Exclude
4	Discovery Park	Exclude
5	Daniel No. 2	Exclude
6	North Shafter Project	Exclude
7	North Shafter Project	Exclude
8	Unification of Wasco Union High School District & Wasco Union Elementary School District	Exclude
9	Central Valley Independent Network Fiber Optic Communitcations Network Project	Exclude
10	24th Street Cul-de-sacs	Exclude
11	24th Street Cul-de-sacs	Exclude
12	24th Street Cul-de-sacs	Exclude
13	24th Street Cul-de-sacs	Exclude
14	24th Street Cul-de-sacs	Exclude
15	24th Street Cul-de-sacs	Exclude
16	24th Street Cul-de-sacs	Exclude
17	24th Street Cul-de-sacs	Exclude
18	South Fork Channel Maintenance Project	Exclude
19	Kern River Channel Maintenance Program	Exclude
20	Kern River Flow and Municipal Water Program	Exclude
21	Strand Ranch Integrated Banking Project	Exclude
22	Conditional Use Permit No. 12-0323	Exclude
23	Berry Petroleum Company Project	Detail
24	General Plan Amendment/Zone Change 12-0349	List
25	FRV Valley Solar Project (PP11297)	List
26	General Plan Amendment/Zone Change No. 12-0355/PD Review No. 12-0356	Exclude
27	Zone Change 15, Map 140; PD Plan 5, Map 140; Exclusion from Ag Preserve 10;	Detail
28	Berry Petroleum Company Project	Detail
29	City of Arvin Circulation Element Update	Exclude
30	Old River Solar Project 2 (PP10267)	List
31	Old River Solar Project 1 (PP10267)	List
32	Bakersfield Pro Resource Management Plan and Final EIS	Exclude
33	NOD - Notice of Determination	Detail
34	FRV Valley Solar Project (PP11297)	List

LINE		
Label	Project	Status
1	BNSF Railway/UPRR Mojave Subdivision Tehachapi Rail Improvement Project	List

POLYGON		
Label	Project	Status
1	Pioneer Green Solar Project (PP11267); 1) CUP 5, Map 30; 2) CUP 5, Map 97; & 3) CUP 6, Map 97	Exclude
2	Pioneer Green Solar Project (PP11267); 1) CUP 5, Map 30; 2) CUP 5, Map 97; & 3) CUP 6, Map 97	Exclude
3	General Plan Amendment/Zone Change 12-0372	List
4	General Plan Amendment/Zone Change 12-0372	List
5	General Plan Amendment/Zone Change 12-0372	List
6	General Plan Amendment/Zone Change 12-0372	List
7	Northern Area Project	Exclude

CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING DIVISION

SOURCE: URS, OpenStreet Map, ESRI & Bing Imagery

HAZARDOUS MATERIALS MANAGEMENT

Alvin Greenberg, Ph.D.

SUMMARY OF CONCLUSIONS

Staff's evaluation of the proposed Hydrogen Energy California (HECA) project, along with staff's proposed mitigation measures, indicates that hazardous materials use at the site would not present a significant impact to the public if all the applicant's mitigation measures are implemented and if staff's proposed conditions are adopted and implemented. Also, with adoption of the proposed conditions of certification, the proposed project would comply with all applicable laws, ordinances, regulations, and standards.

The proposed HECA project is a complex industrial facility similar in scope to a small refinery. The proposed project is a complex chemical processing facility that includes many different types of reactor vessels, storage vessels, treatment units, piping, valves, and flanges as well as transfer and transport facilities which would, if considered separately, each constitute a stand-alone industrial plant. The project proposes to use, store, create, and transport large volumes of several highly toxic hazardous materials. Furthermore, in addition to the actual facilities owned and operated by Hydrogen Energy California, this Preliminary Staff Assessment/Draft Environmental Impact Statement (PSA/DEIS) also includes an environmental review of the high-pressure CO_2 pipeline and enhanced oil recovery and carbon sequestration facility to be owned and operated by Occidental of Elk Hills, Inc.

The different processes and large volumes of hazardous materials that staff has assessed in this PSA/DEIS include the following:

1. A coal/pet coke gasification plant
2. An air separation unit producing cryogenic materials
3. A syngas scrubber, sour shift, low-temperature gas cooling, sour water treatment facility
4. A mercury removal unit
5. An acid gas removal (Rectisol process) unit
6. An ammonia synthesis unit
7. A urea unit
8. A urea pastillation unit
9. A urea pastille handling and transfer unit
10. A urea ammonium nitrate complex that produces nitric acid, ammonium nitrate, and urea
11. A sulfur recovery unit
12. A 13-mile natural gas pipeline
13. A 3-mile pressurized CO_2 pipeline
14. An Enhanced Oil Recovery Facility

15. Additional storage of large volumes of hazardous materials including:
    a. sodium hydroxide
    b. sodium hypochlorite
    c. diesel fuel
    d. gasoline during construction

The presence of these chemical processes -- specifically the larger gasification unit and sulfur recovery unit will process large quantities of hazardous materials in closed tanks and piping at elevated temperature and pressure – could potentially pose significant risks if not managed properly. Staff has not encountered such a complex power generation facility in the history of the Energy Commission. In order to properly review the hazardous materials proposed for use at this project, as well as those hazardous materials that will be produced by the project, staff spent considerable time evaluating the entire process and even visited a similar gasification facility in Polk County, Florida. As a result of staff's efforts to understand the process and the risks involved, staff determined that all of these processes must be managed and monitored carefully, regardless of quantities or the fact that hazardous materials present are below the federal or state thresholds that would trigger this increased level of management if stored.

Therefore, staff is proposing that the project owner be required to develop a Process Safety Management Plan (PSM Plan) which includes a Hazard and Operability analysis to address several different processes, a Risk Management Plan (RMP) which would include several new Offsite Consequence Analyses, and a Spill Prevention Control and Countermeasures (SPCC) Plan for many of the 15 processes identified by staff above. Although these plans and analyses are not necessary for staff to understand and assess the project's impacts under CEQA, staff believes that these plans will identify potential system failures before failure can occur and indicate/implement mitigation to reduce the risk of on-site and off-site consequences to less than significant. This does not mean that staff believes that this project will be 100% free of upsets or accidental releases of hazardous materials. Rather, staff believes that establishing and implementing a strict code of process safety management above and beyond the requirements of existing regulations and implementing engineering and administrative controls to prevent accidents -- followed by quick and effective spill containment, control, and cleanup should an accidental release occur -- will reduce both the chance and severity of an impact to a less than significant level.

As discussed in the **Socioeconomic Resources** section, the minority population in the six-mile buffer of the project site constitutes an environmental justice population as defined by *Environmental Justice: Guidance Under the National Environmental Policy Act*. Staff has not identified any significant adverse direct or Cumulative **Hazardous Materials Management** impacts resulting from the construction or operation of the proposed project, including impacts to the environment justice population. Therefore, there are no **Hazardous Materials Management** environmental justice issues related to this project and no environmental justice populations would be significantly, adversely, or disproportionately impacted.

INTRODUCTION

The purpose of this hazardous materials management analysis is to determine if the proposed Hydrogen Energy California (HECA) project has the potential to cause significant impacts on the public as a result of the use, handling, storage, or transportation of hazardous materials at the proposed site. If significant adverse impacts on the public are identified, Energy Commission staff must also evaluate the potential for facility design alternatives and additional mitigation measures to reduce those impacts to the extent feasible.

The original AFC (08-AFC-8) was filed with the Energy Commission on July 31, 2008; and a Revised AFC was submitted in 2009 to reflect a change of the project site to an alternative location. In 2011, Hydrogen Energy California, LLC, (HECA) was acquired from the previous owners by SCS Energy California, LLC. On May 2, 2012, SCS Energy, LLC, submitted an Amended Application for Certification (08-AFC-8A) reflecting several changes to the original project design.

The new Amended Application for Certification (AFC; HECA 2012e) has been assigned a separate distinguishing docket number, 08-AFC-8A. The Amended AFC for the project supersedes and replaces all previous submissions, and incorporates all relevant information from the previous versions of the HECA proceedings. The applicant intends to construct and operate an Integrated Gasification Combined Cycle (IGCC) power generating facility called Hydrogen Energy California (HECA).

The proposed HECA project would gasify blends of 75 percent western coal and 25 percent petroleum coke from California refineries to produce hydrogen to fuel a combustion turbine operating in combined-cycle mode. The amended project incorporates a proposed manufacturing complex that would produce urea in both liquid and pellet form, and other byproducts for agricultural use. For power generation, a Mitsubishi Heavy Industries MHI 501GAC® CT combustion turbine has been selected. The combined cycle power block would generate approximately 430 MW of gross power and would produce about 300-megawatts of electricity. The gasification unit would separate the carbon from the raw syngas (the direct end product of the gasification process) at steady-state operation, which would be transported by pipeline to a custody transfer point at Elk Hills Oil Field for CO_2 enhanced oil recovery (EOR) and sequestration. Due to the complex gasification and sequestration (storage) process, there is a larger than usual parasitic electrical load.

Highlights of the project include:

- The Amended HECA facility proposes to operate with 25 percent petroleum coke from California refineries blended with 75 percent western bituminous coal. Transportation of coal to the project would be by either a truck route, or via an alternative rail spur proposed to be built and owned by the applicant.
- The feedstock (coal and petroleum coke) would be gasified to produce a synthesis gas (syngas) that would be processed and purified to produce a hydrogen-rich gas, which would be used to fuel the combustion turbine for electric power generation and burners that provide supplemental fire to heat the recovery steam generator (HRSG) that produces steam from the combustion turbine exhaust heat. At least 90 percent of the carbon in the raw syngas would be captured in a high-purity carbon

dioxide stream during steady-state operation, and would be sold to Occidental Petroleum, compressed and transported by pipeline off-site to the nearby Elk Hills Oil Field for injection into deep underground oil reservoirs for enhanced oil recovery (EOR) and sequestration.

- State-of-the-art emission controls are included in the design.
- Zero Liquid Discharge technology is used in the project design for process and waste water.
- Liquid oxygen and nitrogen are produced in the air separation unit, and supplied to the gasification unit, the combustion turbine, sulfur recovery unit and other process components of HECA.

Some notable project changes are proposed in the Amended AFC, including the following:

- Mitsubishi Heavy Industries (MHI) oxygen-blown dry feed gasification technology has been selected.
- A MHI 501GAC® Combustion Turbine and Steam Turbine has been selected.
- A new, integrated manufacturing complex (IMC) will produce approximately 1 million tons per year of low-carbon nitrogen-based products, including urea and urea ammonium nitrate fertilizer, to be used in agricultural applications.

HECA proposes to use two alternatives for delivering coal to the project site:

Alternative 1, Rail Transportation: An approximately 5-mile new industrial railroad spur would connect the project site to the existing San Joaquin Valley Railroad, Buttonwillow railroad line, north of the project site. This railroad spur would also be used to transport some IMC products to customers.

Alternative 2, Truck Transportation: Truck transport would be via existing roads from an existing coal transloading facility northeast of the project site. The truck route distance is approximately 27 miles.

The routes of the natural gas pipeline, potable water pipeline, and electrical transmission have been refined as follows:

- An approximately 13-mile new natural gas pipeline will interconnect with an existing Pacific Gas and Electric Company (PG&E) natural gas pipeline located north of the project site.
- Potable water will be delivered via an approximately 1-mile pipeline from a new West Kern Water District potable water production site east of the project site.
- An approximately 2-mile electrical transmission line will interconnect with a future PG&E switching station east of the project site.
- An approximately 15-mile process water pipeline.

If approved, construction of the project is proposed to begin 2013 or 2014, with completion of construction in 2017, and commencement of commercial operation by the end of 2017.

This analysis does not address the potential exposure of workers to hazardous materials used at the proposed facility. Employers must inform employees of hazards associated with their work and provide them with special protective equipment and training to reduce the potential for health impacts associated with the handling of hazardous materials. The **Worker Safety and Fire Protection** section of this document describes applicable requirements for the protection of workers from these risks.

Anhydrous ammonia and nitric acid are the hazardous materials proposed to be either used or stored at the HECA project in quantities that exceed the reportable amounts defined in Health and Safety Code §25531 et seq and in the California Accidental Release Prevention Program (CalARP) regulations (19 CCR §2770.5). Anhydrous ammonia will be used mainly in the production of UAN (Urea Ammonium Nitrate) fertilizer for shipment off-site. It will also be used to control oxides of nitrogen by selective catalytic reduction (SCR). [The applicant has indicated that their previous plan to ship anhydrous ammonia off-site as a commercial product has been removed from the project.] Anhydrous ammonia has high internal energy and is usually stored as a liquefied gas at high pressure. The high internal energy associated with this stored form of anhydrous ammonia can act as a driving force in an accidental release, which can rapidly introduce large quantities of the material to the ambient air and result in high down-wind concentrations. However, in this case, the applicant has indicated that it will store anhydrous ammonia at close to atmospheric pressure as a refrigerated liquid. If a leak or high internal tank pressure occurs, the anhydrous ammonia will first fill the interstitial space between the inner and outer walls of the double-walled storage tank. When the pressure builds up to a certain point, a pressure relief valve at the top of the tank will release ammonia as a vapor and not as a jet release of liquid anhydrous ammonia. Should both walls of the double-walled tank fail or should the piping fail, anhydrous ammonia will flow as a refrigerated liquid into the third line of defense, a concrete containment structure that would allow the refrigerated anhydrous ammonia to flow into a subsurface vault.

Nitric acid, even though it is an intermediate substance produced and then used in a chemical process, will be temporarily stored in extremely large volumes (5,200,000 lbs) of highly concentrated acid (~60 percent by wt.) for up to three days on-site. Staff therefore believes that nitric acid will also be subject to the Cal-ARP program. Other hazardous materials such as mineral and lubricating oils, methanol, syngas, acid gas, sulfuric acid, and welding gasses will be stored and used or will be generated by the processes of the HECA project.

Hazardous materials used during construction would include gasoline, diesel fuel, motor oil, hydraulic fluid, welding gases, lubricants, solvents, paint, and paint thinner. No extremely hazardous materials will be used on site during construction. None of these materials pose significant potential for off-site impacts as a result of the quantities on site, their relative toxicity, their physical state, and/or their environmental mobility. Handling of hazardous materials during construction would comply with all applicable regulations and would be guided by a Hazardous Materials Business Plan (HECA 2012e).

Although no natural gas is stored, the project will also involve the handling of large amounts of natural gas. Natural gas poses some risk of both fire and explosion. HECA would connect to one of two potential pipeline systems, provided by either Southern

California Gas Company or Pacific Gas and Electric (HECA 2012e). HECA would also require the transportation of some hazardous materials to the facility but will be limited to methanol and sodium hydroxide (HECA 2012e, §5.12.3). This document addresses all potential impacts associated with the transport, use, handling, and storage of hazardous materials.

However, staff wishes to note that many other hazardous materials would be generated and "stored", albeit temporarily in reactor vessels and piping, including extremely hazardous materials such as hydrogen sulfide (H_2S) and carbonyl sulfide (COS). Since H_2S is a by-product of the gasification process and it is removed from the enclosed process system and mostly converted to elemental sulfur (a solid powder with low potential for migration or adverse impacts on people) for sale off-site as liquid sulfur, staff addresses the emissions of H_2S into the atmosphere due to an accidental release in this section and as fugitive emissions from the process system in the **Public Health** section of this PSA/DEIS.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The following federal, state, and local laws and policies apply to the protection of public health and hazardous materials management. Staff's analysis examines the project's compliance with these requirements.

Hazardous Materials Management Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	
The Superfund Amendments and Reauthorization Act of 1986 (42 USC §9601 et seq.)	Contains the Emergency Planning and Community Right To Know Act (also known as SARA Title III).
The Clean Air Act (CAA) of 1990 (42 USC 7401 et seq. as amended)	Established a nationwide emergency planning and response program and imposed reporting requirements for businesses that store, handle, or produce significant quantities of extremely hazardous materials.
The CAA section on risk management plans (42 USC §112(r)	Requires states to implement a comprehensive system informing local agencies and the public when a significant quantity of such materials is stored or handled at a facility. The requirements of both SARA Title III and the CAA are reflected in the California Health and Safety Code, section 25531, et seq.
49 CFR 172.800	The U.S. Department of Transportation (DOT) requirement that suppliers of hazardous materials prepare and implement security plans.
49 CFR Part 1572, Subparts A and B	Requires suppliers of hazardous materials to ensure that all their hazardous materials drivers are in compliance with personnel background security checks.
The Clean Water Act (CWA) (40 CFR 112)	Aims to prevent the discharge or threat of discharge of oil into navigable waters or adjoining shorelines. Requires a written spill prevention, control, and countermeasures (SPCC) plan to be prepared for facilities that store oil that could leak into navigable waters.

Federal Register (6 CFR Part 27) interim final rule	The Chemical Facility Anti-Terrorism Standard (CFATS), a regulation of the U.S. Department of Homeland Security, requires facilities that use or store certain hazardous materials to submit information to the department so that a vulnerability assessment can be conducted to determine what certain specified security measures shall be implemented.
State	
Title 8, California Code of Regulations, section 5189	Requires facility owners to develop and implement effective safety management plans that ensure that large quantities of hazardous materials are handled safely. While such requirements primarily provide for the protection of workers, they also indirectly improve public safety and are coordinated with the Risk Management Plan (RMP) process.
California Health and Safety Code, section 41700	Requires that "No person shall discharge from any source whatsoever such quantities of air contaminants or other material which causes injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause injury or damage to business or property."
California Safe Drinking Water and Toxic Enforcement Act (Proposition 65)	Prevents certain chemicals that cause cancer and reproductive toxicity from being discharged into sources of drinking water.
Hazardous Material Business Plan, Cal HSC Sections 25500 to 25541; 19 CCR Sections 2720 to 2734	Requires the submittal of a chemical inventory and planning and reporting for management of hazardous materials.
The California Accidental Release Prevention Program (CalARP) is found within Health and Safety Code Sections 25531 - 25543.3 (19 CCR §2770.5).	Requires a Risk Management Plan (RMP) that includes air dispersion modeling of an accidental release of certain hazardous materials to determine the off-site consequences of such a release.
Hazardous Substance Information and Training Act, 8 CCR Section 339; Section 3200 et seq., 5139 et seq., and 5160 et seq.	Requires listing and implementation of specified control measures for management of hazardous substances.
California HSC Sections 25270 through 25270.13	Requires the preparation of a Spill Prevention, Control, and Countermeasures (SPCC) Plan if 10,000 gallons or more of petroleum is stored on-site. The above regulations would also require the immediate reporting of a spill or release of 42 gallons or more to the California Office of Emergency Services and the Certified Unified Program Authority (CUPA).
Process Safety Management: Title 8 CCR Section 5189	Requires facility owners to develop and implement effective process safety management plans when toxic, reactive, flammable, or explosive chemicals are maintained on site in quantities that exceed regulatory thresholds.
Local	
County of Kern EHSD	Requires new/modified businesses to complete an HMBP prior to final plan/permit approval.

The Certified Unified Program Agency (CUPA) with the responsibility to review Risk Management Plans (RMPs) and Hazardous Materials Business Plans (HMBPs) is the Kern County Environmental Health Services Department (EHSD) (HECA 2012e, Section 5.12.6.3). With regard to seismic safety issues, the site is located in Seismic Risk Zone 4. Construction and design of buildings and vessels storing hazardous materials will meet the seismic requirements of the 2007 California Building Code and the American Society of Civil Engineers standards ASCE 7-05 (HECA 2012e, Section 2.7.1).

SETTING

Several factors associated with the area in which a project is to be located affect the potential for an accidental release of a hazardous material that could cause public health impacts. These include:

- local meteorology;
- terrain characteristics; and
- location of population centers and sensitive receptors relative to the project.

METEOROLOGICAL CONDITIONS

Meteorological conditions, including wind speed, wind direction, and air temperature, affect both the extent to which accidentally released hazardous materials would be dispersed into the air and the direction in which they would be transported. This affects the potential magnitude and extent of public exposure to such materials, as well as their associated health risks. When wind speeds are low and the atmosphere stable, dispersion is severely reduced but can lead to increased localized public exposure.

Recorded wind speeds and directions are described in the **Air Quality** section (5.1.1.1) and **Appendix E-1** of the Application for Certification (AFC) (HECA 2012e). Staff agrees with the applicant that use of F stability (stagnated air, very little mixing), wind speed of 1.5 meters per second, and an ambient temperature of 115°F are appropriate for conducting the worst-case off-site consequence analyses (HECA 2012e, Appendix L).

TERRAIN CHARACTERISTICS

The location of elevated terrain is often an important factor in assessing potential exposure. An emission plume resulting from an accidental release may impact high elevations before impacting lower elevations. The site topography is predominantly flat (about 282 to 291 feet above mean sea level), with elevated terrain existing about 2 miles south and southwest (HECA 2012e, Section 5.12).

LOCATION OF EXPOSED POPULATIONS AND SENSITIVE RECEPTORS

The general population includes many sensitive subgroups that may be at greater risk from exposure to emitted pollutants. These sensitive subgroups include the very young, the elderly, and those with existing illnesses. In addition, the location of the population in the area surrounding a project site may have a major bearing on health risk. Sensitive receptors and residences in the project vicinity are shown in Figure 5.6-1 of the AFC (HECA 2012e). The nearest sensitive receptor is the Tule Elk State Natural Reserve, which begins about 1,700 feet east of the project site. The only other sensitive receptor within a 6-mile radius of the project site is the Elk Hills Elementary School, located approximately 1.3 miles southeast of the site boundary (HECA 2012e, Section 5.6.1). The nearest residences are located approximately 370 feet northwest of the project site and several hundred feet east of the project site fence line (near the intersection of Tupman Rd and Station Rd). Additional residences are located approximately 1,400 feet to the east and 3,300 feet to the southeast of the project site fence line. The unincorporated community of Tupman is about 1.5 miles southeast of the project site. (HECA 2012e, Sections 5.6 & 5.6.1). The applicant has stated that it will purchase the nearest residence (370 feet from the facility fenceline). Staff believes that this residence's proximity to the facility would place any resident at a significant risk of harm if allowed to continue to reside at that location. If this residence is purchased and demolished this risk would be eliminated.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

Staff reviewed and assessed the potential for the transportation, handling, and use of hazardous materials to impact the surrounding community. All chemicals and natural gas were evaluated. Staff's analysis addresses the potential impacts on all members of the population including the young, the elderly, and people with existing medical conditions that may make them more sensitive to the adverse effects of hazardous materials. In order to accomplish this goal, staff utilized the most current public health exposure levels (both acute and chronic) that are established to protect the public from the effects of an accidental chemical release.

In order to assess the potential for released hazardous materials to travel off site and affect the public, staff analyzed several aspects of the proposed use of these materials at the facility. Staff recognizes that some hazardous materials must be used at power plants. Therefore, staff conducted its analysis by examining the choice and amount of chemicals to be used, the manner in which the applicant will use the chemicals, the manner by which they will be transported to the facility and transferred to facility storage tanks, and the way the applicant plans to store the materials on site.

Staff reviewed the applicant's proposed engineering and administrative controls concerning hazardous materials usage. Engineering controls are the physical or mechanical systems, such as storage tanks or automatic shut-off valves, that can prevent the spill of hazardous material from occurring, or which can either limit the spill to a small amount or confine it to a small area. Administrative controls are the rules and procedures that workers at the facility must follow that will help to prevent accidents or to keep them small if they do occur. Both engineering and administrative controls can act as methods of prevention or as methods of response and minimization. In both cases, the goal is to prevent a spill from moving off site and causing harm to the public.

Staff reviewed and evaluated the applicant's proposed use of hazardous materials as described by the applicant (HECA 2012e, Section 5.12). Staff's assessment followed the five steps listed below:

Step 1: Staff reviewed the chemicals and the amounts proposed for on-site use as listed in **Tables 5.12-1 through 5.12-4** of the AFC (HECA 2012e) and determined the need and appropriateness of their use.

Step 2: Those chemicals proposed for use in small amounts or whose physical state is such that there is virtually no chance that a spill would migrate off site and impact the public were removed from further assessment.

Step 3: Measures proposed by the applicant to prevent spills were reviewed and evaluated. These included engineering controls such as automatic shut-off valves and different-sized transfer-hose couplings and administrative controls such as worker training and safety management programs.

Step 4: Measures proposed by the applicant to respond to accidents were reviewed and evaluated. These mitigation measures also include engineering controls such as catchment basins and methods to keep vapors from spreading and administrative controls such as training emergency response crews.

Step 5: Staff analyzed the theoretical impacts on the public of a worst-case spill of hazardous materials, as reduced by the mitigation measures proposed by the applicant. When mitigation methods proposed by the applicant are sufficient, no further mitigation is recommended. If the proposed mitigation is not sufficient to reduce the potential for adverse impacts to an insignificant level, staff will propose additional prevention and response controls until the potential for causing harm to the public is reduced to an insignificant level. It is only at this point that staff can recommend that the facility be allowed to use hazardous materials.

Also, as discussed in the Introduction, this PSA/DEIS analyzes the project's impacts pursuant to both the National Environmental Policy Act (NEPA) and CEQA. The two statutes are similar in their requirements concerning analysis of a project's impacts. Therefore, unless otherwise noted, staff's use of, and reference to, CEQA criteria and guidelines also encompasses and satisfies NEPA requirements for this environmental document.

DIRECT/INDIRECT IMPACTS AND MITIGATION

The proposed HECA project would consist of a complex industrial facility containing numerous chemical processes that will require large amounts of hazardous materials in closed tanks and piping at elevated temperature and pressure. This has the potential to pose significant risks if not managed properly. Therefore, in order to properly review the hazardous materials proposed for use at this project, as well as those that will be produced by the project, staff reviewed the entire gasification system and ancillary processes and visited a similar gasification facility, the Polk Power Station near Tampa, Florida. During that visit, staff discussed routine and accidental emissions, frequency of flares and upset conditions, fugitive emissions from piping, flanges, valves, and pumps, the Process Safety Management analysis for a potential syngas explosion, fire detection and suppression systems, waste streams, and general operating information. According to the owners of the Polk Power Station, there have been no significant accidental releases of hazardous materials or significant fires or explosions in the history of the power plant (commercial operations started in September 1986). There has been, however, frequent incidences of small syngas fires/explosions during start-ups and shut-downs. If the explosion occurs in the gasifier, the vessel contains the explosion.

Nevertheless, as a result of staff's efforts to understand the process and the risks involved, staff determined that the number and large volumes of hazardous materials and the processes that use these hazardous materials must be assessed and managed in greater detail than usual, regardless if the quantities of materials present are below federal or state thresholds for regulation. The procedure staff used was modified to address the volumes and elevated temperature and pressures that the facility would operate under. Staff therefore reviewed the entire list of hazardous materials provided by the applicant and will require strict adherence to HAZ-1 so that any deviation from this list is reviewed and approved in advance by the CPM.
The reasons staff made the decisions to require additional mitigation measures beyond standard administrative and engineering controls for certain hazardous materials can be found in **Hazardous Materials Management Table 2.**

Hazardous Materials Management Table 2
Additional Mitigation Needs

Material	Application	Maximum Quantity On Site	Further Review and Mitigation	Reasons for Yes/No Mitigation
Anhydrous Ammonia	Emissions control (SCR), fertilizer feedstock	3,8000,000 gallons	**Yes**	High vapor pressure; high volume; high danger
Boiler Feedwater Chemicals (e.g., Morpholine, Cyclohexamine and Sodium Sulfite)	Boiler feedwater pH/corrosion / dissolved oxygen/biocide control	< 500 gallons	No	Very small quantity and low vapor pressures; aqueous mixtures.
Chemical Reagents (acids/bases/ standards)	Lab	< 5 gallons	No	Very small quantities.
Compressed Gases (Ar, He, & other lab gases)	Lab	Minimal	No	Very small volumes.
Cooling Water Chemical Additives (e.g., Magnesium Nitrate, Magnesium Chloride)	Corrosion inhibitor/biocides	< 500 gallons	No	Very small volumes; pose little risk off-site.

Material	Application	Maximum Quantity On Site	Further Review and Mitigation	Reasons for Yes/No Mitigation
CTG and HRSG Cleaning Chemicals (e.g., HCl, Citric Acid, EDTA Chelant, Sodium Nitrate)	HRSG chemical cleaning	Intermittent cleaning requirement/ temp storage only	No	Intermittent use; standard admin and engineering controls adequate to prevent off-site impacts.
Diesel Fuel	Emergency generator/fire water pump fuel	2,000 gallons	No	Standard admin and engineering controls adequate to prevent off-site impacts.
Flammable/Hazardous Gases (H_2S, COS, Syngas and Hydrogen-Rich Gas)	Primary power generation fuel	All would be present as process quantities only with no storage on site except that within pipes and reactor vessels.	**Yes**	Highly flammable, explosive, or toxic. PSM Plan and other plans needed to control and minimize accidents
Hydrogen (H_2)	STG & CTG generator cooling	30,000 standard cubic feet	No	Small volume stored on commonly-used storage trailer.
Methanol	AGR solvent make-up	300,000 gallons	**Yes**	Toxic; flammable at elevated temp & pressure
Methyldiethanolamine (40%)	Solvent for sulfur removal	220,000 pounds	No	Low vapor pressure.
Miscellaneous Industrial Gases – Acetylene, Oxygen, Other welding Gases, Analyzer Calibration Gases	Maintenance welding/ instrumentation calibration	Minimal	No	Very small volumes and low toxicity; little risk of off-site impacts.
Liquid Sulfur	By-product for sale and to be de-gassed and then shipped off-site	1,400,000 lbs (air space in storage tank truck or rail car can contain high levels of H_2S and COS)	**Yes**	Solid and non-volatile; low toxicity yet off-gases sig quantities of H_2S and can be a fire and explosion hazard at high temp

Material	Application	Maximum Quantity On Site	Further Review and Mitigation	Reasons for Yes/No Mitigation
Natural Gas	Startup/backup/ auxiliary fuel	Utility supplies on demand via pipeline	**Yes**	Highly flammable
Nitric Acid ~60 % by wt.	Intermediate, produced/used in UAN Plant	5,200,000 lbs (~3 day supply)	**Yes**	Very toxic, corrosive, and reactive
Nitrogen (95%) Liquid	For production of anhydrous ammonia	100,000 lbs	**Yes**	Inert gas but poses a danger as a cryogenic
Oxygen (95%), Liquid	Gasification, SRU	24,000,000 lbs	**Yes**	Highly corrosive and high risk of accelerating a fire.
Paint, Thinners, Solvents, Adhesives, etc.	Shop/warehous e	< 20 gallons	No	Very low volumes and low toxicity.
Sodium Hydroxide (5% - 50%)	Plant wastewater, sour water treatment, gasification, caustic scrubber	150,000 gallons	No	Very low vapor pressure and aqueous solution.
Sulfuric Acid	Plant wastewater, Cooling water pH control	14,000 gallons	No	Very low vapor pressure.
UAN soln.	product	126,000,000 lbs	**Yes**	Very low vapor pressure, aq. soln., but can be explosive if allowed to dry

Source: HECA 2012e, Tables 5.12-3 & 5.12-4

Staff also looked at the various process operations and researched the accident history of similar operations at other locations. The applicant also provided some information on this subject in response to a staff data request (HECA 2012kk). A summary of each operation and potential for upsets/releases follows. This information was used by staff to determine the need for precautionary preventative measures to mitigate potential significant impacts.

Coal/pet coke Gasification Plant

The Gasification Plant converts solid feedstock (blended coal and petcoke which has been ground and dried) to syngas. The gasifier process involves two stages. In the first stage the feed enters the gasifier into a lower stage with oxygen where it is gasified at high temperature to produce CO, CO_2 and water vapor. These gases rise to the second stage, more feed is added without oxygen, and the gasification of char to CO and shifting of CO and water to hydrogen and CO_2 occurs, producing syngas. The syngas passes through a cooler, generating steam which is used in power generation. Staff visited a similar gasification facility located in Polk County, Florida and discussed upsets and accidental releases from the gasifier and other processes. Staff also reviewed reports of operations from another similar gasification facility in Terra Haute, Indiana (the Wabash River facility) that included assessments of problems (U.S. DOE 2002a and 2002b; Keeler 1999). In all cases, the releases, upsets, and problems were minor and gases did not migrate off-site and thus there was no significant threat to the off-site public. However, the fact that minor explosions and releases from the gasifier and attached piping in one of the facilities examined has occurred supports staff's contention that increased controls and safety management plans are indeed warranted for the proposed HECA facility.

Air Separation Unit (ASU)

The ASU filters, compresses, dries and cools ambient air to cryogenic temperatures for separation of oxygen (high-pressure, high-purity O_2 for use in the Gasifier and low-pressure, low-purity O_2 for use in the SRU) and nitrogen (high-purity for use in the Ammonia Synthesis Unit and other processes). Staff could find no records of accidents or releases from ASUs in the literature.

Syngas Scrubber, Sour Shift, Low-temperature Gas Cooling, Sour Water Treatment Facility.

Syngas from the Gasifier is treated in the Syngas Scrubber to remove chlorides. The scrubbed syngas is converted to CO_2 and hydrogen in the Sour Shift Unit and then sent to the ammonia wash column to remove any ammonia present in the syngas. From there the syngas is sent to the Mercury Removal Unit.

Accident experience at similar units

ExxonMobil Baton Rouge Refinery, LA, March 24-25, 2006

A leak was discovered on the ammonia gas line to the No. 100 Sulfur Plant due to a corrosion hole under the edge of a clamp. When tightening the clamp did not stop the leak, the Sour Water Stripper (SWS) was shut down. A new clamp was installed which also leaked. The old clamp was reinstalled with a new gasket but this did not stop the leak. Feed spheres to the SWSs became full and SWSs were started-up to the flare system; ammonia acid gas was flared for over 8 hours. Air monitoring was conducted offsite for ammonia, H_2S and SO_2; all readings were below detection level.

(Source: Louisiana Bucket Brigade, "Louisiana's Worst Refinery Accidents 2005-2008.")

Phillips 66, CA, June 15, 2012

Sour water tank over-pressured causing split in roof and release of vapors. Strong sulfur odors detected by Hazmat personnel at Interstate-80 and surrounding communities. Highest reading was about 1 ppm H2S on I-80 (a few hundred feet from the storage tank).

(Source: "Major Accidents at Chemical/Refinery Plants in Contra Costa County", summaries since 1992)

Mercury Removal Unit

Mercury is removed from the syngas using activated carbon and then the syngas is sent to the AGR Unit. Staff could find no records of accidents or releases from mercury removal units in the literature.

Acid Gas Removal (Rectisol process) Unit (AGR)
Acid gases are removed from the syngas to produce hydrogen-rich fuel that feeds the combined cycle power block. A portion of this fuel serves as a feedstock to the Ammonia Synthesis Unit. CO_2 is separated in this step, compressed and transported for enhanced oil recovery (EOR) and sequestration. Staff could find no records of accidents or releases from Rectisol units in the literature.

Ammonia Synthesis Unit
High-purity hydrogen from the AGR and high-purity nitrogen from the ASU are compressed to high pressure, heated and fed to the ammonia synthesis converter where, over an iron-based catalyst, conversion to ammonia occurs. This unit contains a natural gas-fired start-up heater. The ammonia produced is used onsite to produce urea pastilles and UAN solution, which are both shipped offsite.

Accident experience at similar units

Accidental Releases of Anhydrous Ammonia, United States
Houston, Texas, 1976: tanker drove off elevated road and burst. Grass burned in all directions around the crash.

Pensacola, Florida, 1977: Train derailed and ammonia tank car punctured. About 4 minutes after the crash air traffic control at nearby Pensacola airport (directly upwind) observed ammonia cloud on radar, about 1 mile in diameter and 125 feet high. Cloud remained visible on radar for an hour and travelled 9 miles (it did not lift off the ground).
(Source: Kaiser GD and RF Griffiths. 1982. "The Accidental Release of Anhydrous Ammonia to the Atmosphere: A Systematic Study of Factors Influencing Cloud Density and Dispersion." Journal of the Air Pollution Control Association. Vol. 32, No. 1. January.)

Accidental Releases of Anhydrous Ammonia, Minnesota, 1995-2005
459 accidental releases of anhydrous ammonia reported in Minnesota from 1995-2005. 47 of the 459 events caused injury with 136 people injured.

- >593,000 lbs released (some during illegal drug activities),
- 27% of these events resulted in evacuations and/or injuries,
- ≈ 4,150 people evacuated during 96 of these events,
- 391 (85%) of these events occurred at fixed facilities (above ground storage, piping, ancillary process equipment, transportation within fixed facility, material handling),
- 265 of these events due to equipment failure, 93 due to human error, 43 were intentional or illegal, 6 were weather related and 52 unknown,

Examples of accidental releases:

- ≈ 1,000 gallons released when nurse tank rolled over on a road. 1 injury requiring treatment at a hospital, road closed for about 4 hours, 5 nearby residences evacuated for 2 hours,
- 9000 lbs released in a leak from a refrigeration system, 18 employees sought medical evaluation, 9 required treatment,

- Ammonia stored in makeshift containers for illegal methamphetamine production released when containers failed. 11 people injured (chemical burns, respiratory irritation), 15 residences evacuated,
- Tanker truck full of anhydrous ammonia overturned on a busy highway near a city. Highway closed for more than 9 hours while tanker offloaded (only a small amount ammonia was released). 375 people evacuated from homes.

(Source: "An Overview of Accidental Anhydrous Ammonia Releases in Minnesota." Environmental Health Information, Minnesota Department of Health. January 2007.)

Ammonia Incidents, Minnesota

- October 20, 2005: tanker truck holding 20 tons anhydrous ammonia rolled over off Highway 169. Portions of highway closed, local residences evacuated. Ammonia pumped into another tanker, very little released.
- June 6, 2005: Non-code weld weakened the shell of an anhydrous ammonia nurse tank and caused rupture. Tank propelled about 250 feet. Extensive ammonia vapor cloud drifted away from populated areas; some nearby residents treated for exposure.
- January 18, 2002: Freight train derailed 31 of its 112 cars about a half-mile from Minot, North Dakota. 15 of the 31 cars contained anhydrous ammonia. 240,000 gallons released to soil and air creating a vapor plume that drifted toward Minot. One resident died, 11 people had serious injuries and 322 people were seen by medical personnel.

(Source: "Ammonia Incident Summaries". Minnesota Department of Agriculture.)

Urea Unit

Some of the compressed CO_2 from the AGR is treated in the CO_2 Purification Unit, producing high quality CO_2 for urea synthesis. CO2 is combined with ammonia from the Ammonia Synthesis Unit in the Urea Reactor, producing urea solution to be used in the Urea Pastillation Unit and the Urea Ammonium Nitrate (UAN) Complex.

Accident experience at similar units

Urea Production Plant, France, March 27, 1998

- Ammonia leak occurred between 4:50 – 6:25 am on a liquid ammonia pipe running from medium-pressure storage zone to urea synthesis unit due to defective safety rupture disc. 10 tons ammonia released over 90 minutes from a 100 m stack. Technicians misinterpreted alarms.
- Nearby residents woke up to smell of ammonia; highly unfavorable weather conditions (slight wind and temperature inversion) amplify the effects of the ammonia leak. Ammonia concentrations near the olfactory threshold (5 ppm) were measured at several locations in the city. Population told to remain indoors. No medical impacts reported.
- Ammonia concentrations measured in the city (north of the plant) between 7:30 – 9 am at 3-5 ppm. Local atmospheric monitoring sensors recorded maximum level of 3 ppm. Ammonia detectors installed at periphery of plant were detrimental since the release occurred from a 100 m stack.
- Accident occurred due to equipment malfunction and human error.

(Source: "Ammonia Leak in a Urea Production Plant. March 27, 1998. Toulouse (Haute-Garonne) France." French Ministry for Sustainable Development. September 2010.)

Urea Pastillation Unit and Urea Pastille Handling and Transfer Unit
Droplets of urea solution are deposited onto a moving belt, the droplets solidify to produce a uniform pastille product, and this product is then collected for storage and export off-site. Staff found no reports of incidences in the data bases searched.

Urea Ammonium Nitrate Complex
Several intermediate products are produced during UAN synthesis (nitric acid, ammonium nitrate and urea). Nitric acid production first involves catalytic oxidation of ammonia from the Ammonia Synthesis Unit at high temperature to yield nitric oxide and water. Nitric oxide reacts non-catalytically with oxygen to produce nitrogen dioxide, which is cooled and sent to an absorption tower to react with water to produce nitric acid and nitric oxide. Gaseous ammonia and aqueous nitric acid undergo an exothermic reaction to produce ammonium nitrate, which is mixed with urea to produce UAN.

Accident experience at similar units

Terra International, Port Neal Complex, Iowa, December 13, 1994
[Staff believes that this facility is perhaps the most similar to the UAN production plant proposed for the HECA facility. The Terra plant produced an 83% ammonium nitrate (AN) solution by reacting ammonia and nitric acid in a vessel called a neutralizer. The nitric acid plant supplied the nitric acid. Also onsite was anhydrous ammonia stored in two pressurized storage vessels. The AN solution was sold or mixed with urea to form a urea-ammonium nitrate solution.]
Explosion occurred in the ammonium nitrate plant releasing about 5,700 tons of anhydrous ammonia to the air and secondary containment, about 25,000 gallons nitric acid to the ground and lined chemical ditches and sumps and liquid ammonium nitrate solution into secondary containment. Offsite ammonia released continued for about 6 days. Released chemicals caused groundwater contamination under the facility. Four employees were killed as a direct result of the explosion and 18 others were injured and required hospitalization. The investigation team concluded that the explosion resulted from a lack of written, safe operating procedures that lead to in unsafe conditions in the AN process at the plant. The specific process conditions that caused the explosion were: excess acid levels in the neutralizer and rundown tank, prolonged application of 200 psig steam to the neutralizer nitric acid spargers, creation of bubbles and low density zones in the neutralizer, lack of flow in the neutralizer and rundown tank, presence of chloride contamination in the neutralizer and rundown tank, and lack of process monitoring after the plant was shut down. Plumes and clouds of ammonia were monitored as far away as 5 miles from the facility.
(Source: US EPA Region 7. "Chemical Accident Investigation Report. Terra Industries, Inc. Nitrogen Fertilizer Facility. Port Neal, Iowa.")

Sulfur Recovery Unit (SRU)
Acid gas from the AGR, sour gas from the sour water strippers and various plant vents feed the SRU. H_2S in the feed is oxidized to sulfur dioxide in a reaction furnace. The SO_2 reacts with remaining H_2S to produce elemental sulfur, which is stored and then shipped offsite.

Accident experience at similar units

Big West, Bakersfield, CA, September 2008

A release of sulfur dioxide above the reportable quantity occurred due to failure in the sulfur recovery system. Amount released unknown, no fires, injuries or evacuation reported.

CITGO Lake Charles Refinery, LA, June 19, 2006
Heavy rainfall caused shutdown of the Central Amine Unit and subsequent shutdown of SRUs due to lack of feed. SRU shutdown caused the Sour Water Stripper off-gas to be flared. Air monitoring during the release showed ERPG-2 (Emergency Response Planning Guidance Level 2) values were never exceeded. No SO_2 or H_2S was detected at the location of odor complaints.
(Source: Louisiana Bucket Brigade, "Louisiana's Worst Refinery Accidents 2005-2008.")

CITGO Lake Charles Refinery, LA, June 4-5, 2007
Short duration rain event with winds gusting over 60 mph and hail resulted in loss of power at one of CITGO's substations. This caused loss of amine flow and H_2S absorption in amine contactors at the Light Ends Recovery Unit resulting in heavy smoking from refinery boiler stacks, excess SO_2 emissions from heaters and boilers and upset to the Sulfur Recovery Plant (SRP) with subsequent excess H_2S emissions from tail gas units at the SRP. Air monitoring during the release showed ERPG-2 values were never exceeded.
(Source: Louisiana Bucket Brigade, "Louisiana's Worst Refinery Accidents 2005-2008.")

Placid Refining Co., LLC, Port Allen, TX
Equipment failure incidences:

- September 2008: SRU out of service, sour water off-gases with H_2S flared while SRU down
- June 2009: Sulfur unit malfunction due to overheating, resulting in flaring of acid gas and sour water (over 11,000 lbs SO_2 released)
- February 2012: SRU shutdown caused product to be incinerated rather than converted (900 lbs SO_2 released)

(Source: Louisiana Bucket Brigade, database of incidents)

Conoco Phillips, Contra Costa County, CA, March 18, 2007
Sulfur plant shutdown due to power failure causing excess sulfur to flare. No complaints received from community.
(Source: "Major Accidents at Chemical/Refinery Plants in Contra Costa County", summaries since 1992)

Shell Oil Products, Martinez Refinery, CA, March 26, 2006
Community Warning System sirens were sounded due to release of SO_2 gas from SRU #3. Elevated temperatures in one of the catalyst beds may have resulted in production of SO_2 gas. Visible plume was seen across Shell Avenue which was believed could pose a health hazard and Shell Avenue was closed for 25 minutes. Visible pluming stopped within 15 minutes. Event downgraded to level 0 within 40 minutes. Hazardous Materials Program staff responded within 10 minutes of event start. Hand-held monitoring equipment did not detect any SO_2 or H_2S although a slight SO_2 odor was reported at Shell Avenue and Marina Vista.
(Source: "Major Accidents at Chemical/Refinery Plants in Contra Costa County", summaries since 1992)

Tesoro Golden Eagle Refinery, CA, October 26, 2005

Partial power outage resulted in ammonia recovery unit shutdown to reduce acid gas load to sulfur plant. Plume visible off-site (potentially containing SO_2). No odor impact reported by odor patrol in nearby Clyde. Ground level monitors did not detect SO_2 or H_2S.

(Source: "Major Accidents at Chemical/Refinery Plants in Contra Costa County", summaries since 1992)

Sunoco's Oregon Refinery, OR, October 16, 2004

Excess SO_2 emissions from the Sulfur Recovery Unit occurred over a 24-hour period. SRU was out of compliance due to Hydrocracker unit and Sour Water Stripper startup. No offsite air monitoring conducted.

(Source: "Sunoco's Oregon Refinery: 21 accidents in the last 6 months." March 10, 2005)

Exxon Mobil Refinery, Torrance CA, December 2004

Sulfur dioxide was released from the sulfur recovery unit when the analyzer maxed out because the facility was in the middle of switching the sour water strippers. No fires, injuries or evacuation reported.

Valero Refining CO, Benicia CA, June 2003

A flaring incident of sulfur dioxide occurred; the release was caused by an upset in the sulfur recovery unit. Amount released: 630 pounds. No fires, injuries, or evacuation reported.

Shell, Martinez, CA, April 2002

Sulfur Recovery Unit #3 was being shut down on the morning of 4/23/02 to address concerns about SO_2 stack emissions, which were approaching the BAAQMD limit of 250 ppm/hr. SRU#3 converts acid gas consisting of SO_2 and H_2S to elemental sulfur in a catalytic reactor utilizing the "Claus" process, the same process proposed for the HECA project. The SRU#3 vent gas is routed through a Shell Claus Offgas Treatment (SCOT) plant for additional treatment. The SCOT-3 vent gas is routed through a catalytic oxidizer to convert remaining H_2S to SO_2. By 11:00 am all acid gas feed had been removed from SRU#3. Approximately an hour later, the catalytic oxidizer experienced a temperature excursion (most likely resulting from burning sulfur), which led to a plume from the SCOT-3 stack by 12:30 p.m. At 12:30 p.m., Shell called the incident a Level 1 alert. At 12:35 am, Shell upgraded the incident to a Community Warning System Level 3 alert and sounded sirens. Steam and nitrogen were used to cool the catalytic oxidizer. Contra Costa County Health Services field observations identified a black plume, which dissipated very quickly and no plume was visible after about 10 or 15 minutes. Shell secured the unit at 12:57 pm.

(Source: "Major Accidents at Chemical/Refinery Plants in Contra Costa County", summaries since 1992)

Chevron, Richmond, CA, January 2002

Release of sulfur dioxide from the #3 SRU plant. A high vapor/liquid flow condition was created by the Isomax #4 H2S plant when a normal heat exchanger backwash was being performed, which caused an interlock plant shutdown at #3 SRU. The momentary release occurred while restarting the plant (Level 3 initiated by CCHS). A few calls were reported to the facility expressing concern or inquiring as to the activity taking place. People in Richmond were asked to shelter-in-place.

Chevron Richmond, CA, January 31, 2002

SO_2 released from #3 SRU Plant during start-up. The facility received calls from the community expressing concern or inquiring as to what was happening. People in Richmond asked to shelter-in-place.

(Source: "Major Accidents at Chemical/Refinery Plants in Contra Costa County", summaries since 1992)

Tosco (now Conoco Phillips) Crockett, CA, April 1997

An upset in the distillation unit sent hydrocarbons to the sulfur recovery units. Parts of the refinery were shut down until the problem was found. People were asked to shelter-in-place at Tormey and Crockett.

Natural Gas Pipeline

A new natural gas pipeline will be about 13 miles long, connecting the project with an existing PG&E natural gas pipeline located north of the site. Expected delivery pressure is 335 psig (minimum). Gas pipelines are subject to internal and external cathodic degradation, seam leaks, backhoe attacks, rust, and seismic rupture. However, building and inspecting the gas pipeline as per existing codes and regulation would render risks posed to the public insignificant.

CO_2 pipeline

CO_2 from the AGR is compressed and will be transported by an approximately 3-mile pipeline to Elk Hills Oil Field for enhanced oil recovery and sequestration. Minimum pressure for the CO_2 pipeline is 2,500 psig.

Accident experience at similar units

Dakota Gasification Company

Pipeline 328 km, capacity 5 million tons/year. The gas stream averages 95.95% CO_2 with an average of 0.8% H_2S. Operations began in 2000 and since then only one minor leakage accident occurred due to component failure.

(Source: Duncan IJ et al. 2008. "Risk Assessment for Future CO_2 Sequestration Projects Based on CO2 Enhanced Oil Recovery in the US. Presented at the 9th International Conference on Greenhouse Gas Control Technologies, Washington DC. November.)

Denbury Pipeline Complex

Pipeline 562 km, longest section constructed in 1980s. Five accidental releases of CO2 have occurred; two leaks were due to manufacturing imperfections in welds, one leak occurred when an excavator accidentally cut the line, one leak occurred when cement lined pipe ruptured due to inadequate weld pre-heating and one leak occurred at a pump station. Leaks were short in duration.

(Source: Duncan IJ et al. 2008. "Risk Assessment for Future CO_2 Sequestration Projects Based on CO2 Enhanced Oil Recovery in the US. Presented at the 9th International Conference on Greenhouse Gas Control Technologies, Washington DC. November.)

US Pipelines

Currently about 2,400 km of large CO_2 pipelines in operation, most in the US, many operating since the early 1980s. From 1990 to 2001, 10 pipeline incidents occurred in the US, four caused by relief valve failure, three by weld/gasket/valve packing failure, two by corrosion and one due to outside force (which includes human error accidents). No injuries or fatalities have occurred due to CO_2 pipeline incidents.

(Source: Gale J and Davison J. 2005. "Transmission of CO_2: Safety and Economic Considerations." Energy. 29: 1319-1328.)

Enhanced Oil Recovery Facility

CO_2 from HECA will be transported to Elk Hills Oil Field for enhanced oil recovery and sequestration. EOR involves injection and reinjection of CO_2, which reduces viscosity and enhances other properties of trapped oil to improve extraction. In this process the injected CO_2 becomes trapped or sequestered underground. Staff could find no records of accidents or releases from EOR units that use CO_2 in the literature.

Construction Phase Analysis

Various hazardous materials, liquid, gaseous, and solid, would be used during the construction of the project. Hazardous materials such as welding gases, lead acid batteries, paints, solvents, cleaning acids, lubricating oils, etc. are stored in low volumes while fuels such as diesel and gasoline with be stored on-site in moderate volumes (4000 gallons each; HECA 2012e Table 5.12-1 and 5.12-2). In staff's experience at other power plant sites under construction, the amounts and nature of these materials pose an insignificant risk to off-site public if a spill were to occur since fuels must be stored and dispensed with spill containment around the storage tank and the dispensing nozzles. However, because of the very large amounts of diesel fuel and gasoline that would be stored on the site for the duration of construction, staff proposes Condition of Certification **HAZ-8** to reduce the risk of fires and/or explosion involving fuels or the risk of a spill to an insignificant level.

Operations Phase Analysis

Small Quantity/Low Risk Hazardous Materials

Hazardous chemicals such as hydrogen, sulfuric acid, mineral and lubricating oils, cleaning detergents, welding gasses, and other various chemicals would be used and/or temporarily stored at the HECA site. (See **Hazardous Materials Appendix B** for a list of all chemicals proposed for use and storage at HECA). In conducting the analysis, staff determined in Steps 1 and 2 that these materials, although present at the proposed facility, pose a minimal potential for off-site impacts since they will be stored either in small quantities, used in an enclosed system, have low mobility/volatility, or have low levels of toxicity. These hazardous materials are eliminated from further consideration. [note: A large amount of carbon dioxide will be transported via pipeline to the Elk Hills Field and federal regulations (49 CFR 195) required the applicant to prepare a risk analysis for the pipeline. The risk analysis determined that the risk of pipeline failure was less than significant.]

After removing from consideration those chemicals that pose no risk of off-site impact in Steps 1 and 2, staff continued with Steps 3, 4, and 5 to review the remaining large quantity hazardous materials:

1. natural gas
2. syngas
3. methanol
4. liquid oxygen
5. molten and liquid sulfur
6. anhydrous ammonia.

The project will be limited to using, storing, and transporting only those hazardous materials listed in Appendix B of this document as per staff's proposed condition **HAZ-1**.

Large Quantity Hazardous Materials

Natural Gas

Natural gas poses a fire and/or possible explosion risk because of its flammability. Natural gas is composed mostly of methane, but also contains ethane, propane, nitrogen, butane, isobutene, and isopentane. It is colorless, odorless, and tasteless and is lighter than air. Natural gas can cause asphyxiation when methane is 90% in concentration. Methane is flammable when mixed in air at concentrations of 5 to 14%, which is also the detonation range. Natural gas, therefore, poses a risk of fire and/or possible explosion if a release occurs under certain specific conditions. However, it should be noted that, due to its tendency to disperse rapidly (Lees 1998), natural gas is less likely to cause explosions than many other fuel gases such as propane or liquefied petroleum gas, but can explode under certain conditions (as demonstrated by the July 2004 natural gas detonation in Belgium).

While natural gas would be used in significant quantities, it would not be stored on site. It would be delivered via a 13 mile-long natural gas interconnection with Pacific Gas & Electric (PG&E) natural gas pipelines located north of the project site (HECA 2012e, Section 5.12). The risk of a fire and/or explosion on site can be reduced to insignificant levels through adherence to applicable codes and the development and implementation of effective safety management practices. The National Fire Protection Association (NFPA) code 85A requires both the use of double-block and bleed valves for gas shut off and automated combustion controls. These measures will significantly reduce the likelihood of an explosion in gas-fired equipment. Additionally, start-up procedures would require air purging of the gas turbines prior to start up, thereby precluding the presence of an explosive mixture. The safety management plan proposed by the applicant would address the handling and use of natural gas and would significantly reduce the potential for equipment failure because of either improper maintenance or human error.

Since the proposed facility will require the installation of a new gas pipeline off-site, impacts from this pipeline need to be evaluated. The design of the natural gas pipeline is governed by laws and regulations discussed here. These LORS require use of high quality arc welding techniques by certified welders and inspection of welds. Many failures of older natural gas lines have been associated with poor quality welds, or corrosion. Current codes address corrosion failures by requiring use of corrosion resistant coatings and cathodic corrosion protection. Another major cause of pipeline failure is damage resulting from excavation activities near pipelines. Current codes address this mode of failure by requiring clear marking of the pipeline route. An additional mode of failure is damage caused by earthquake. Existing codes also address seismic hazard in design criteria (see discussion below). Evaluation of pipeline performance in recent earthquakes indicates that pipelines designed to modern codes perform well in seismic events while older lines frequently fail. Staff believes that existing regulatory requirements are sufficient to reduce the risk of accidental release from the pipeline to less than significant levels.

Failures of gas pipelines, according to data from the U.S. Department of Transportation (the National Transportation Safety Board) from the period 1984 – 1991 and data from the National Response Center for the period 1990 - 2004, occur as a result of pipeline corrosion, pipeline construction or materials defects, rupture by heavy equipment excavating in the area such as bulldozers and backhoes, weather effects, and earthquakes. Given the gas line failures which occurred in the Marina District of San Francisco during the 1989 Loma Prieta earthquake, the January 1994 Northridge earthquake in Southern California, the January 1995 gas pipeline failures in Kobe, Japan, the January 19, 1995 gas explosion in San Francisco, the pipeline explosion in Belgium in July 2004, the natural gas storage fire in Texas in August 2004, and the San Bruno gas pipeline explosion and fire in Sept. 2010, the safety of the gas pipeline is of paramount importance. However, it must be noted that those pipelines which failed in 1989 to 1995 were older and not manufactured nor installed to modern code requirements. The February 2001 Nisqually Earthquake near Olympia Washington caused no damage to natural gas mains and there was only one reported gas line leak due to a separation of a service line going into a mobile home park. The Belgium gas pipeline explosion was due to construction equipment rupturing the line, not due to earthquake or structural failure.

If loss of containment occurs as a result of pipe, valve, or other mechanical failure or external forces, significant quantities of compressed natural gas could be released rapidly. Such a release can result in a significant fire and/or explosion hazard, which could cause loss of life and/or significant property damage in the vicinity of the pipeline route. However, the probability of such an event is extremely low if the pipeline is constructed according to present standards. According to DOT statistics, the frequency of reportable incidents is about 0.25 for all pipeline incidents per 1,000 miles per year or 2.5×10^{-4} incidents per mile per year. DOT has also evaluated and categorized the major causes of pipeline failure. To summarize, the four major causes of accidental releases from natural gas pipelines are: Outside Forces – 43 percent, Corrosion -18 percent, Construction/Material Defects -13 percent, and Other - 26 percent. Outside forces are the primary causes of incidents. Damage from outside forces includes damage caused by use of heavy mechanical equipment near pipelines (e.g., bulldozers and backhoes used in excavation activities), weather effects, vandalism, and earthquake-caused rupture as seen in the Marina District of San Francisco during the 1989 Loma Prieta Quake and in Kobe, Japan in January 1995. The fourth category, “Other” includes equipment component failure, compressor station failures, operator errors and sabotage. The average annual service incident frequency for natural gas transmission systems varies with age, the diameter of the pipeline, and the amount of corrosion. Older pipelines have a significantly higher frequency of incidents. These result from the lack of corrosion protection and use of less corrosion resistant materials compared to modern pipelines, limited use of modern inspection techniques, and higher frequency of incidents involving outside forces. The increased incident rate due to outside forces is the result of the use of a larger number of smaller diameter pipelines in older systems, which are generally more easily damaged and the uncertainty regarding the locations of older pipelines.

The safety requirements for pipeline construction vary according to the population density and land use that characterize the surrounding land. The pipeline classes are defined as follows (Title 49, Code of Federal Regulations, Part 192):

Class 1: Pipelines in locations within 220 yards of ten or fewer buildings intended for human occupancy in any 1-mile segment.

Class 2: Pipelines in locations within 220 yards of more than ten but fewer than 46 buildings intended for human occupancy in any 1-mile segment. This class also includes drainage ditches of public roads and railroad crossings.

Class 3: Pipelines in locations within 220 yards of more than 46 buildings intended for human occupancy in any 1-mile segment, or where the pipeline is within 100 yards of any building or small well-defined outside area occupied by 20 or more people on at least 5 days a week for 10 weeks in any 12 month period (the days and weeks need not be consecutive). (The proposed project gas pipeline would fall into this class.)

Class 4: Pipelines in locations within 220 yards of buildings with 4 or more stories above ground in any 1-mile segment.

In the United States, extensive federal and state pipeline codes and safety enforcement minimize the risk of severe accidents related to natural gas pipelines. In November 2000, the DOT Office of Pipeline Safety proposed a program requiring the preparation of risk management plans for gas pipelines throughout the United States. These risk management plans will include the use of diagnostic techniques to detect internal and external corrosion or cracks in pipelines and to perform preventive maintenance. The pipeline owner will be required to develop and implement these plans as per the regulation adopted May 2004 (49 CFR Part 192). The regulations prescribe minimum requirements for a pipeline Integrity Management Program to be prepared and followed by every operator of a pipeline segment located in a high consequence area. A high consequence area is defined as any location where the pipeline traverses a Class 3 or 4 area (see above) or other areas under specified circumstances. The integrity management program must contain the required elements as described in section 192.911, including an identification of all high consequence areas, a baseline assessment plan including methods of assessing pipeline integrity and a schedule for completing the assessment, an identification of threats to each pipeline segment including a risk assessment, an evaluation of mitigation measures, implementation procedures, and monitoring procedures. The regulations also include requirements for reassessment intervals, which range from 7 to 20 years depending on the type of reassessment and the operating percentage of the pipeline.

The following safety features will be incorporated into the design and operation of the natural gas pipeline (as required by current federal and state codes): (1) while the pipeline will be designed, constructed, and tested to carry natural gas at a certain pressure, the working pressure will be less than the design pressure; (2) butt welds will be X-rayed and the pipeline will be tested with water prior to the introduction of natural gas into the line; (3) the pipeline will be surveyed for leakage annually (4) the pipeline will be marked to prevent rupture by heavy equipment excavating in the area; and (5) valves at the meter will be installed to isolate the line if a leak occurs. These requirements will be administered by the federal government and the CPUC.

The natural gas pipeline must be designed to meet all standards of the California Public Utilities Commission General Order 112, Federal Department of Transportation (DOT) regulations, Title 49, Code of Federal Regulations (CFR), Parts 190, 191, and 192, and ASME B31 piping codes. CPUC General Order 112-E, Section 125.1 requires that at least 30 days prior to the construction of a new pipeline, the owner must file a report with the commission that will include a route map for the pipeline. Staff concludes that compliance with existing LORS would be sufficient to ensure minimal risks of pipeline failure.

Furthermore, on June 28 2010 the United States Chemical Safety and Hazard Board (CSB) issued Urgent Recommendations to the United States Occupational Safety and Health Administration (OSHA), the National Fire Protection Association (NFPA), the American Society of Mechanical Engineers (ASME), and major gas turbine manufacturers to make changes to their respective regulations, codes, and guidance to require the use of inherently safer alternatives to natural gas blows for the purposes of pipe cleaning. Recommendations were also made to the fifty states to enact legislation applicable to power plants that prohibits flammable gas blows for the purposes of pipe cleaning. In accordance with those recommendations, staff proposes Condition of Certification **HAZ-12** which prohibits the use of a flammable gas blow for pipe cleaning at the facility either during construction or after the start of operations. All fuel gas pipe purging activities shall vent any gases to a safe location outdoors, away from workers and sources of ignition. Fuel gas pipe cleaning and purging shall adhere to the provisions of most current versions of the National Fuel Gas Code (NFPA 54) including all Temporary Interim Amendments.

Syngas

Syngas poses a fire and/or possible explosion risk because of its flammability. Syngas contains hydrogen (H_2), carbon monoxide (CO), sulfur dioxide (SO_2), and hydrogen sulfide (H_2S). Syngas has a broader flammable and detonation range than natural gas because it is a mixture of chemicals with more diverse properties. Syngas also contains an extremely hazardous material, H_2S, which is scrubbed from the syngas and subsequently removed from the enclosed process system and mostly converted to elemental sulfur, a solid powder with low potential for migration or adverse impacts on the off-site public. It is then transferred for sale off-site. Up to 150,000 gallons of degassed molten sulfur will be stored on site in two sulfur storage pits. The storage pits will also be equipped with pressure-monitoring equipment and ventilation lines while the sulfur-loading equipment will have a vapor recovery system to control fugitive emissions of hydrogen sulfide by returning vapors to the SRU.

A catastrophic loss of the syngas would result in the release of significant amounts of H_2S and thus the applicant modeled a worst-case accidental release. Staff addresses the emissions of H_2S into the atmosphere as an accidental release in this section and as fugitive emissions from the process system in the **Public Health** section of this PSA/DEIS.

The applicant's modeling of an accidental release of hydrogen sulfide shows that the acute Reference Exposure Level (REL) would not be exceeded at off-site locations where the public drives and lives. Staff has also found that the modeling of fugitive emissions of H_2S emitted from the CO_2 vent shows that the acute REL would also not be exceeded, thus indicating no potential for adverse impacts to the public. (See the **Public Health** section for a thorough analysis of this issue.)

Sulfur Recovery Unit (SRU)

Hydrogen sulfide can be released from a failure of the sulfur recovery unit (SRU). Staff reviewed the past accident history of SRUs in California over the past 20 years and found that although there have been numerous releases of sulfurous chemicals at refineries in California (over 1,600 in the past 20 years); only about 80 of the reports specify the sulfur recovery unit as the source of the release. Thus, many of the incidents could involve components of a sulfur recovery system since it is a common system in refineries.

The vast majority of the reports of accidental releases at SRUs in California found in the National Response Center (NRC) database (see discussion above) show that most releases consist of sulfur dioxide (SO_2) and not H_2S. However, SO_2 will be produced in great quantities during the gasification process at the proposed HECA project and then will be combined with H_2S to produce elemental sulfur. (Sulfur dioxide will also be released from several sources into the atmosphere including the main stack, the SRU, and the Tail Gas Thermal Oxidizer). Therefore, because SO_2 will be produced by the HECA process, staff finds the reports of releases from refinery SRUs to be germane to the safety of the proposed process.

Although minor sulfur dioxide releases and other small incidents are common at sulfur recovery units, such incidents rarely produce fires, injuries, significant damage, or a need for evacuation. Sulfur recovery units at California facilities recorded roughly 100 incidents over the past 20 years, most of them without significant consequences. Therefore, staff proposes to address the risk management of this hazardous material by requiring that the Cal-OSHA Process Safety Management standard (8 CCR 5189) be followed and that a process hazard analysis and a Process Safety Management Plan (PSM Plan, which includes a Hazard and Operability analysis) and a Risk Management Plan (RMP, which would include a new Offsite Consequence Analysis different from the one prepared by the applicant in the AFC) be prepared.

In regards to the requirement to conduct a process safety management analysis and prepare a PSM Plan, staff strongly believes that it is imperative that the applicant understands that the entire Cal-OSHA Process Safety Management standard (8 CCR 5189) must be strictly followed and implemented. Towards that, staff believes that when conducting the process hazard analysis required in 8 CCR 5189 (e) (1), the project owner should perform a hazard analysis using at least two different methodologies. One shall be a Hazard and Operability Study (HAZOP) and the other can be chosen from the list in 5189 (e) (1) or one which is recognized by engineering organizations or governmental agencies.

Second, an independent outside third party group of professionals must provide peer review and approval of the plan before the plan is submitted to the Energy Commission compliance project manager (CPM) for approval. The most important part of the hazard review is described in 8 CCR 5189 (e)(3)(A) which requires that “The process hazard analysis shall be performed by a team with expertise in engineering and process operations, and the team shall include at least one operating employee who has experience and knowledge specific to the process being evaluated. The team shall also include one member knowledgeable in the specific process hazard analysis methodology being used. The final report containing the results of the hazard analysis for each process shall be available in the respective work area for review by any person working in that area". Staff proposes Condition of Certification **HAZ-9** which would require two hazard analyses be conducted and that an independent outside third party that also has the required expertise be hired by the project owner to review, evaluate, and sign-off on all process hazard analyses and PSM plans required by Energy Commission conditions. It would further require the project owner to develop and implement a pipeline integrity management plan that is consistent with the U.S. DOT Pipeline and Hazardous Materials Safety Administration (PHMSA) Liquid Pipeline Integrity Management in High Consequence Areas for Hazardous Liquid Operators (49 CFR Parts 195.450 and .452) rule, the recommendations of the U.S. Chemical Safety and Hazard Investigation Board in its report on the August 2, 2012 Chevron Richmond Refinery Fire, and the recommendations of the independent professionals retained as per the requirement mentioned above. This requirement applies not only to the SRU but all other processes identified by staff as needing a PSM Plan.

Methanol

Methanol (methyl alcohol) will be used as a gasifier start-up fuel and in the acid gas remover (AGR) and sulfur recovery unit. This use will be at elevated temperature and pressure thus increasing the potential for an accidental release, explosion, or fire. The applicant addressed the risk and impacts of a vapor cloud explosion and fire of the above-ground storage tank holding 300,000 gallons of methanol. Worst-case modeling indicated that a pressure wave of 1 psi would impact up to 4224 feet distant from the tank location (HECA 2012e Section 5.12.2.3) This impact would be beyond the Controlled Area and may impact the nearest residence (1400 feet from the control area fence line) but would not cause an impact at the school located 1.3 miles (6864 feet) away.

Staff proposes to address the risk management of this hazardous material by requiring a process hazard analysis and Process Safety Management Plan (PSM Plan, which includes a Hazard and Operability analysis) and a Risk Management Plan (RMP, which would require a new Offsite Consequence Analysis addressing explosion and fire). These analyses are conducted on the facility "as built" and thus serve as an extra method to identify potential problems before they occur. Staff believes that these plans will identify potential system failures and mitigation and thus allow for the implementation of additional engineering and administrative controls to further reduce the risk of off-site consequences to the public to less than significant. The applicant also will reduce the risk of fire or explosion at the methanol tank by utilizing an aqueous film forming foam as the fire suppression system. And, as described above, this process hazard analysis shall include at least two different methodologies and be reviewed and approved by an independent third party professional reviewer before submitting to the CPM for review and final approval.

Liquid Oxygen and Liquid Nitrogen

Liquid oxygen and liquid nitrogen are compressed gases stored as cryogenic liquids. As such, both are extremely dangerous and liquid oxygen is extremely corrosive and a potent oxidizer. Should a fire occur near the liquid oxygen tank and the tank or fittings rupture, a conflagration could ensue. Staff researched the incident rates of accidents and releases involving liquid oxygen tanks in the past 20 years and found that although the rate was low, they do occur. A review of the 15 incidents of liquefied oxygen releases in the United States alone found that worker deaths and injuries are not common and thus liquid oxygen storage does not pose a significant risk. Of these 15 incidents, 13 releases were due to the failures of valves, fittings, pipe leaks, gauges, and delivery vehicle hose couplings, or involved a small (20 cu ft) tank rupture due to a fall. In most cases, only a few hundred pounds of liquid oxygen was released, however, in one case, >20,000 pounds escaped. In 1999, in Bristol, MA, an oxygen bulk tank exploded and released 200 gallons. No injuries or evacuation were reported and the cause of the failure was not determined. In February 1978, three persons were killed in New Martinsville, WV when liquid oxygen escaping from a pipe at a chemical plant set off a very large explosion and fire. All land, air and river traffic was halted for about seven hours while officials waited for the 900-ton liquid oxygen tank to exhaust its supply. The cause was determined to be a pipe rupture at an air separation facility when a liquid nitrogen vessel broke and a portion fell on the liquid oxygen pipe.

Staff proposes to address the risk management of this hazardous material by requiring a process hazard analysis and Process Safety Management Plan (PSM Plan, which includes a Hazard and Operability analysis) and a Risk Management Plan (RMP, which includes an Offsite Consequence Analysis). The applicant will also install pressure relief valves and automatic shutdown equipment for the tank and oxygen delivery system that will reduce the likelihood of an accidental release. Staff believes that these plans will identify potential system failures and additional mitigation and thus, when combined with the applicant's proposed controls, will reduce the risk of off-site consequences to the public to less than significant. And, as described above, this process hazard analysis shall include at least two different methodologies and be reviewed and approved by an independent third party professional reviewer.

Molten and Liquid Sulfur

Molten sulfur and cooled liquid sulfur would be produced as a by-product of the gasification and sulfur removal processes and shipped off-site for sale after being de-gassed. Sulfur would be in a liquid suspension and would not, in and of itself, pose a hazard to the off-site public. However, the presence on the site of an extremely high amount (as much as 1,400,000 lbs at any one time) and the fact that the air space in the on-site storage container, tank truck, or rail car can contain high levels of extremely toxic hydrogen sulfide (H_2S) and carbonyl sulfide (COS) presents the potential for very high risk to on-site works and the off-site public. Thus, although liquid sulfur is non-volatile and of low toxicity at low temperatures, it has the potential to off-gas significant quantities of H_2S and can also be a fire and explosion hazard at high temperature. In order to address this matter when shipping this product off-site, staff proposes Condition of Certification **HAZ-10** which would require continual testing of the H_2S levels in the airspace above the shipping vehicle (tanker truck or rail tank car) and prohibit the off-site transport until the levels of H_2S fell below 2 ppm. The project owner would be able to address this matter in several ways including increasing the de-gassing period or adding active vapor removal equipment.

Anhydrous Ammonia

Anhydrous ammonia would be used to control the emission of oxides of nitrogen (NO_x) from the combustion of natural gas at the HECA project and as a feedstock for the production of ammonia-based fertilizer. The accidental release of anhydrous ammonia without proper mitigation can result in significant down-wind concentrations of ammonia gas. HECA would store up to 3,800,000 gallons in two above-ground ammonia tanks with a maximum capacity each of 1,900,000 gallons (HECA 2012e, Sections 5.12.2.2). The tanks will be double-walled (primary containment) and would be surrounded by a secondary containment basin (3-foot high wall) capable of holding the full contents of the tank plus the rainfall associated with a 24-hour 25-year storm. The secondary containment would slope to a drain to allow spilled ammonia to flow into a subsurface sump. (HECA 2012e, Sections 5.12.2.2 and data responses). Both tanks with their separate secondary containments would then be surrounded with a tertiary containment basin with 4-foot high walls.

Based on staff's analysis described above and the applicant's responses to staff's data requests, anhydrous ammonia is one of the hazardous materials that may pose a significant risk of off-site impact. The use of ammonia can result in the release of ammonia vapor in the event of a spill. This is a result of its vapor pressure and the large amounts of ammonia that will be used and stored on site.

To summarize, if the applicant's and staff's proposed conditions are adopted and the project is certified, the applicant would be required to develop and implement several engineering and administrative controls in order to reduce the chances of an accidental release of anhydrous ammonia, and to reduce the impacts of a release should one occur, including the following:

1. use of two double-walled storage tanks
2. secondary containment that drains into a subsurface sump
3. another third containment system that surrounds the tanks and the pumps used to transfer anhydrous ammonia from and to process units
4. the use of strategically fixed and mobile handheld ammonia sensors
5. the preparation and implementation of Process Safety Management Plans, HazOp studies, Safety Management Plans, spill prevention and control plans, and emergency response plans
6. the use of personal protective equipment (PPE) for on-site workers
7. interaction and training with the off-site responders from the Kern County Fire Department (KCFD; see section on Worker Safety/Fire Protection in this PSA/DEIS)

To assess the potential impacts associated with an accidental release of anhydrous ammonia should one occur, staff uses four benchmark exposure levels of ammonia gas occurring off site. These include:

1. the lowest concentration posing a risk of lethality, 2,000 parts per million (ppm);
2. the concentration immediately dangerous to life and health level of 300 ppm;
3. the emergency response planning guideline level 2 of 150 ppm, which is also the RMP level 1 criterion used by U.S. Environmental Protection Agency (EPA) and California; and
4. the level considered by the Energy Commission staff to be without serious adverse effects on the public for a one-time exposure of 75 ppm.

If the potential exposure associated with a potential release exceeds 75 ppm at any public receptor, staff will also assess the probability of occurrence of the release, the severity of the consequences, and the nature of the potentially exposed population in determining whether the likelihood and extent of potential exposure are sufficient to support a finding of potentially significant impact. A detailed discussion of the exposure criteria considered by staff, as well as their applicability to different populations and exposure-specific conditions, is provided in **Hazardous Materials Appendix A**.

Section 5.12.2.3 and **Appendix K** of the AFC (HECA 2012e) describe the modeling parameters used for the worst-case and the alternative accidental releases of anhydrous ammonia in the applicant's off-site consequence analysis (OCA). The OCA was performed for the worst-case release scenario, which involved the failure and complete discharge of the storage tank. The highest average recorded temperature (115°F), a wind speed of 1.5 meters per second, and atmospheric stability class F were used for emission and dispersion calculations to present worst-case conditions. Potential off-site ammonia concentrations were estimated using the ALOHA Gaussian plume model (HECA 2012e, **Appendix K** Section 3.1.1).

Figures showing how far the predicted ammonia concentrations would extend from the anhydrous ammonia tank under different accident release scenarios were provided as confidential information to staff. The applicant's modeling results for the most likely release scenario -- an accident involving the pumps moving ammonia into or out of the tanks and forming a pool of ammonia within the secondary containment area from which a lighter-than-air dispersion of ammonia would occur -- show that ammonia concentrations exceeding 75 ppm extend a little beyond the facility fence line to the east but do not reach any residential receptor. The modeling required by U.S. EPA using the air dispersion model required and assessing the complete rupture of one tank, shows that ammonia concentrations exceeding 75 ppm could extend as far as the town of Tupman. Staff has found in the past that the modeling required by the U.S. EPA using the RMP Comp program is ultra-conservative and provides little useful information for assessing impacts under CEQA. Since this modeling is so very conservative and overestimates the airborne concentration of ammonia should an accidental release occur from the storage tanks, staff concludes that the applicant's alternative modeling of the most likely release scenario demonstrates no off-site impact. Given the number of administrative and engineering controls required by federal, state and local regulations as well as staff's proposed conditions of certification for the anhydrous ammonia tank, piping, and pumps, staff believes that the storage and use of anhydrous ammonia will not result in a significant risk to the off-site public.

Mitigation

The potential for accidents resulting in the release of hazardous materials is greatly reduced through implementation of a safety management program that would include the use of both engineering and administrative controls. Elements of both facility controls and the safety management plan are reiterated and summarized below. Staff met with several representatives of the County Environmental Health Service Department (KCEHSD) and discussed their concerns and views on impacts to the county.

Engineering Controls

Engineering controls help to prevent accidents and releases (spills) from moving off site and affecting communities by incorporating engineering safety design criteria in the design of the project. The engineered safety features proposed by the applicant for use at the HECA project include:

- Storage of containerized hazardous materials in their original containers which are designed to prevent releases and are appropriately labeled.
- Construction of secondary containment areas surrounding each of the hazardous materials storage areas designed to contain accidental releases that might happen during storage or delivery.
- Physical separation of stored chemicals in isolated containment areas in order to prevent accidental mixing of incompatible materials, which could result in the evolution and release of toxic gases or fumes.
- Installation of local level gauges and alarms to prevent overfilling of bulk chemical storage tanks.
- Construction of a containment area surrounding the anhydrous ammonia storage tanks, sodium hydroxide tanks, sulfuric acid tank, sodium hypochlorite tank, diesel fuel tank, and lubricating oil tank capable of holding the entire contents of each tank plus the volume of rainfall associated with a 24-hour 25-year storm.
- The placement of a subsurface vault into which spilled anhydrous ammonia would flow thus reducing the surface area of a spill.
- Process protective systems including continuous tank level monitors, automated leak detectors, ammonia and hydrogen sulfide detectors, temperature and pressure monitors, alarms, and isolation valves.
- Hydrogen shall be stored on site (30,000 standard cubic feet or scf) within a multi-tube trailer and shall be monitored and controlled through the use of flow meters and pressure monitors. The hydrogen system shall also be equipped with pressure relief valves and automatic shutdown.
- Not greater than 150,000 gallons of degassed molten sulfur shall be stored on site within two sulfur storage pits. Both sulfur storage pits shall be constructed of compatible material, shall be structurally sound (free of any cracks or fissures), and shall be equipped with pressure-monitoring equipment and ventilation lines. In addition, sulfur-loading equipment shall have a vapor recovery system to control fugitive emissions by returning displaced vapors to the SRU.
- Methanol in the process unit shall be stored in a single 300,000-gallon AST with secondary containment. An additional 250,000 gallons of methanol will also be contained within process vessels, equipment, and piping of the AGR unit. This process inventory shall be kept geographically remote from the 300,000-gallon AST, and a pump and isolation valve shall be placed on the piping between the storage tank and the AGR unit isolating the AST and AGR unit. The tanks shall also be equipped with leak detectors to identify the presence of any liquid accumulation below the tank bottom or in the containment area. The methanol delivery system shall be equipped with a flow meter and automatic shutdown capabilities. The

methanol transfer pump and piping shall have secondary containment to collect any potential spills.

- Sodium phosphate shall be contained in an AST located at the indoor chemical storage area. The sodium phosphate ASTs shall be equipped with secondary containment and leak detectors to detect the presence of a rupture.
- The closed-loop cooling system of the process equipment that contains propylene glycol as a heat transfer fluid shall be equipped with leak detection equipment.
- The use of an extensive buffer-zone around the actual gasification facility and production processes so as to place distance between the facility and public roads. The perimeter of the buffer zone will also contain an earthen berm on the north and east sides of the entire site fence line.

Administrative Controls

Administrative controls also help prevent accidents and releases (spills) from moving off site and affecting neighboring communities by establishing worker training programs, process safety management programs, and complying with all applicable health and safety laws, ordinances, and standards.

A worker health and safety program will be prepared by the applicant and include (but not be limited to) the following elements (see the **Worker Safety and Fire Protection** section for specific regulatory requirements):

- worker training regarding chemical hazards, health and safety issues, and hazard communication;
- procedures to ensure the proper use of PPE;
- safety operating procedures for the operation and maintenance of systems utilizing hazardous materials;
- fire safety and prevention; and
- emergency response actions including facility evacuation, hazardous material spill clean-up, and fire prevention.

At the facility, the project owner will be required to designate an individual with the responsibility and authority to ensure a safe and healthful work place. The project health and safety official will oversee the health and safety program and have the authority to halt any action or modify any work practice to protect the workers, facility, and the surrounding community in the event of a violation of the health and safety program.

The applicant will also prepare a risk management plan for anhydrous ammonia, as required by both U.S. EPA and CalARP regulations and Condition of Certification **HAZ-2**. This condition also includes the requirement for a program for the prevention of accidental releases and responses to an accidental release of anhydrous ammonia. A hazardous materials business plan will also be prepared by the applicant that would incorporate state requirements for the handling of hazardous materials (HECA 2012e, Section 5.12.2.2). Additional administrative controls are required by **HAZ-2** including preparation of a Hazardous Materials Business Plan, a Process Safety Management Plan for several processes, and a Spill Prevention, Control, and Countermeasure Plan).

Other administrative controls would be required in proposed Conditions of Certification **HAZ-1** (limitations on the use and storage of hazardous materials and their strength and volume) and **HAZ-3** (development of a safety management plan). Proposed Condition **HAZ-9** would require an independent outside professional review and agreement with all process safety management evaluations and plans before the CPM approves them and the development and implementation of a pipeline integrity management plan that is consistent with the U.S. DOT Pipeline and Hazardous Materials Safety Administration (PHMSA) Liquid Pipeline Integrity Management in High Consequence Areas for Hazardous Liquid Operators (49 CFR Parts 195.450 and .452) rule, the recommendations of the U.S. Chemical Safety and Hazard Investigation Board in its report on the August 2, 2012 Chevron Richmond Refinery Fire, and the recommendations of the independent professionals retained. Proposed Condition **HAZ-4** would require that the anhydrous ammonia storage tank be designed to certain specifications.

Proposed condition **HAZ-12** would prohibit the past practice of using natural gas to “blow” debris from piping. And finally, command and control systems in a complex facility such as that proposed here must be protected from failure or damage. Process controls and sensors, fire detection and suppression, and communications are all vital to the safe operation of an industrial facility. Towards that, redundancy is required and all redundant command and control systems that are “hard-wired” must be placed in separate wiring tracks so that if one wiring track is compromised, both command and control systems would not be lost. Therefore, staff proposes Condition of Certification **HAZ-11** that would require the project owner to ensure that all redundant command and control systems that are “hard-wired” are placed in separate wiring tracks.

On-Site Spill Response

In order to address the issue of spill response, the facility will prepare and implement an emergency response plan that includes information on hazardous materials contingency and emergency response procedures, spill containment and prevention systems, personnel training, spill notification, on-site spill containment, and prevention equipment and capabilities, as well as other elements. Emergency procedures will be established which include evacuation, spill cleanup, hazard prevention, and emergency response.

The presence of oil in a quantity greater than 1,320 gallons invokes a requirement to prepare a Spill Prevention Control and Countermeasures (SPCC) Plan. The applicant has indicated that 2000 gallons of diesel fuel will be stored on site. While there are no known waters of the United States immediate adjacent to this site, there are Waters of the State and thus a SPCC Plan is required by 40 CFR 112. State law also applies in that pursuant to California HSC Sections 25270 through 25270.13, the project will store 10,000 gallons or more of petroleum on-site (when the lube oil and the transformers oil are included). The above regulations would also require the immediate reporting of a spill or release of 42 gallons or more to the California Office of Emergency Services and the Certified Unified Program Authority (CUPA).

Designated plant personnel would be trained as first responders for hazardous materials incidents. In the event of a large spill, the Kern County Fire Department Hazmat Response Unit located in Bakersfield would respond to the project site, and contracted hazardous materials clean-up teams would also be available (HECA 2012e, Section 5.12.6.3 and 5.8.1.3). Staff finds that the available local hazmat teams and clean-up companies are capable of responding to a hazardous materials emergency call from HECA with an adequate response time.

Transportation of Hazardous Materials

Hazardous materials including large volumes of sodium hydroxide and methanol will be transported to the facility by tanker truck during operation of the facility. Diesel fuel and gasoline will also be transported to the site and stored on the site during construction. While many types of small volumes of hazardous materials will be transported to the site, based on staff's knowledge and past experience with the transportation of a wide variety of hazardous materials, staff believes that transport of these two materials would pose an insignificant risk to the off-site public should a spill occur. This is due to the low vapor pressure and low concentration of aqueous sodium hydroxide (5-50%) precluding a spill from spreading very far through the air and due to the very high vapor pressure of methanol resulting in the fast dissipation (volatilization) of methanol in the air.

There would also be large amounts of degassed liquid sulfur along with urea ammonium nitrate fertilizer transported off the site for delivery to distant purchasers. Staff believes that the UAN fertilizer poses an insignificant risk of harm to the off-site public should there be a spill because it is in solid form and is used and transported extensively without mishap in agricultural regions of California and the United States. Liquid sulfur, however, may pose a different problem and may pose an inhalation hazard to the off-site public if it is not thoroughly de-gassed of hydrogen sulfide (H_2S). Liquid sulfur will be transported in rail tank cars or tanker trucks specifically designed and permitted for this type of hazardous material and will be at a temperature of ~284° F (140° C) (HECA 2012e, section 5.12.4.2). In order to ensure that the liquid sulfur is properly degassed and residual levels of H_2S do not pose a hazard to the off-site public in the event of a transportation spill, staff proposes Condition of Certification **HAZ-10** which would require the project owner to ensure through on-site testing that no batch of degassed liquid or molten sulfur loaded into a rail tank car or tanker truck would be allowed to leave the site unless the H_2S levels have been found to be less than 2 ppm.

Staff reviewed the applicant's proposed transportation routes for hazardous materials delivery. Trucks would travel from Bakersfield using Stockdale Highway to Morris Road to Station Road to the project's gate (HECA 2012e, Section 5.12.3 and Figure 5.12-1). Alternative routes will only be used if hazardous materials are transported from non-major suppliers.

A liquid or gaseous hazardous material can be released during a transportation accident and the extent of impact in the event of such a release would depend upon the location of the accident and the rate of dispersion of ammonia vapor from the surface of the aqueous ammonia pool. The likelihood of an accidental release during transport is dependent upon three factors:

1. the skill of the tanker truck driver;
2. the type of vehicle used for transport; and
3. accident rates.

To address this concern, staff evaluated the risk of an accidental transportation release in the project area. Staff's analysis focused on the project area after the delivery vehicle leaves the main highway (Stockdale). Staff believes it is appropriate to rely upon the extensive regulatory program that applies to the shipment of hazardous materials on California highways to ensure safe handling in general transportation (see Federal Hazardous Materials Transportation Law 49 USC §5101 et seq, DOT regulations 49 CFR subpart H, §172–700, and California Department of Motor Vehicles (DMV) regulations on hazardous cargo). These regulations also address the issue of driver competence. See AFC section 5.10 for additional information on regulations governing the transport of hazardous materials.

To address the issue of tanker truck safety, all hazardous materials will be delivered to the proposed facility in DOT-certified vehicles.

To address the issue of accident rates, staff reviewed the technical and scientific literature on hazardous materials transportation (including tanker trucks) accident rates in the United States and California. Staff relied on six references and three federal government databases to assess the risk of a hazardous materials transportation accident. Staff used the data from the Davies and Lees (1992) article, which references both the 1990 Harwood et al. and 1993 Harwood studies, to determine that the frequency of release for the transportation of hazardous materials in the U.S. is between 0.06 and 0.19 releases per 1,000,000 miles traveled on well-designed roads and highways. The short distance from Interstate-5 to the facility is approximately 4 miles (one way). Even using the high number of delivery vehicles coming into the facility to deliver hazardous materials and the number of trucks leaving the site with liquid sulfur (if rail tank cars are not used), the number of miles driven by vehicles transporting hazardous materials of sufficient volume and volatility to pose a risk to the public if spilled is very small, on the order of 4000 miles (1000 trips at 4 miles per trip). Staff believes that the risk over this distance is insignificant. Data from the U.S. DOT show that the actual risk of a fatality over the past five years from <u>all</u> modes of hazardous material transportation (rail, air, boat, and truck) is approximately 0.1 in 1,000,000.

Staff therefore believes that the risk of exposure to significant concentrations of any hazardous material during transportation to the facility is insignificant because of the remote possibility that an accidental release of a sufficient quantity could be dangerous to the public. The transportation of similar volumes of hazardous materials on the nation's highways is neither unique nor infrequent. Staff's analysis of the transportation of aqueous ammonia to the proposed facility (along with data from the U.S. DOT) demonstrates that the risk of accident and exposure is less than significant.

In order to further ensure that the risk of an accident involving the transport of methanol or sodium hydroxide to the power plant or liquid sulfur from the facility are insignificant, staff proposes an additional administrative control in proposed Condition of Certification **HAZ-6** that would require the use of only one specific route to the site, that being the shortest route from and to Interstae-5 using Stockdale Highway, Morris Road, and Station Road.

Based on the environmental mobility, toxicity, the quantities at the site, and frequency of delivery, it is staff's opinion that that the risk associated with the transportation of hazardous materials to or from the proposed project (with the possible exception of liquid sulfur) is below the level of significance. Regarding liquid sulfur, as discussed above, staff believes the risk posed by an accidental release of liquid sulfur can be reduced to a level of insignificance by ensuring that the material is not allowed to leave the site until it is demonstrated that the airspace in the tanker truck or rail tank car does not have a concentration of H_2S above 2 ppm. The project owner would be able to address this matter in several ways including increasing the de-gassing period or adding active vapor removal equipment.

Seismic Issues

It is possible that an earthquake could cause the failure of a hazardous materials storage tank. An earthquake could also cause failure of the secondary containment system (berms and dikes), as well as the failure of electrically controlled valves and pumps but the presence of a back-up power supply would mitigate any loss of primary power. Nevertheless, although a remote possibility, the failure of all of these preventive control measures might then result in a vapor cloud of hazardous materials that could move off site and affect residents and workers in the surrounding community. The effects of the Loma Prieta earthquake of 1989, the Northridge earthquake of 1994, and the earthquake in Kobe, Japan, in January 1995, have all heightened concerns about earthquake safety.

Information obtained after the January 1994 Northridge earthquake showed that some damage was caused both to several large storage tanks and to smaller tanks associated with the water treatment system of a cogeneration facility. The tanks with the greatest damage, including seam leakage, were older tanks, while the newer tanks sustained displacements and failures of attached lines. Therefore, staff conducted an analysis of the codes and standards which should be followed when designing and building storage tanks and containment areas to withstand a large earthquake. Staff also reviewed the impacts of the February 2001 Nisqually earthquake near Olympia, Washington, a state with similar seismic design codes as California. No hazardous materials storage tanks failed as a result of that earthquake. Referring to the sections on **Geologic Hazards and Resources** and **Facility Safety Design** in the AFC, staff notes that the proposed facility will be designed and constructed to the standards of the 2010 California Building Code and the American Society of Civil Engineers standards (ASCE 7-05) for Seismic Zone 4 (HECA 2012e, Section 2.8.1).

Staff has also reviewed reports of the impacts of the earthquakes in Haiti (January 12, 2010; magnitude 7.0) and Chili (February 27, 2010; magnitude 8.8). The building standards in Haiti are extremely lax while those in Chile are as stringent and modern as California seismic building codes. Yet, the preliminary reports show a lack of impact on hazardous materials storage and pipelines infrastructure in both countries. For Haiti, this most likely reflects a lack of industrial storage tanks and gas pipelines; for Chili, this most likely reflects the use of strong safety codes.

Therefore, on the basis of what occurred in Northridge with older tanks and the lack of failures during the Nisqually earthquake (with newer tanks) and in the 2010 Chilean earthquake, staff determined that tank failures during seismic events are not probable and do not represent a significant risk to the public. All structures and hazardous materials storage tanks/structure at the proposed facility must be built to codes for Seismic Zone 4, the highest level possible.

Site Security

Background

The applicant proposes to use hazardous materials identified by the U.S. EPA as requiring the development and implementation of special site security measures to prevent unauthorized access. The U.S. EPA published a Chemical Accident Prevention Alert regarding site security (EPA 2000a), the U.S. Department of Justice published a special report entitled *Chemical Facility Vulnerability Assessment Methodology* (US DOJ 2002), the North American Electric Reliability Corporation published *Security Guidelines for the Electricity Sector* in 2002 (NERC 2002) as well as issued a Critical Infrastructure Protection standard for cyber security (NERC 2009), and the U.S. Department of Energy (DOE) published the draft *Vulnerability Assessment Methodology for Electric Power Infrastructure* in 2002 (DOE 2002). The energy generation sector is one of 14 areas of critical infrastructure listed by the U.S. Department of Homeland Security. On April 9, 2007, the U.S Department of Homeland Security published in the Federal Register (6 CFR Part 27) an interim final rule requiring that facilities that use or store certain hazardous materials conduct vulnerability assessments and implement certain specified security measures. This rule was implemented with the publication of Appendix A, the list of chemicals, on November 2, 2007. This proposed facility plans to store anhydrous ammonia solution in an amount that will place the facility under the requirements of the CFATS regulation.

Analysis

Staff received a needs assessment from the California Highway Patrol and the Kern County Sheriff's Department regarding security (CHP 2012a, CHP 2013a; Kern County 2013a). The CHP indicated that it would serve as a back-up to the Kern County Sheriff's Department on emergency responses to the site with a response time of 5 to 10 minutes, that response times could be effected by the increase of traffic during construction and operations, but that an increase in resources was probably not needed. The Kern County Sheriff indicated that its response time would be 10 to 15 minutes to the site, that response times could be impacted during construction but not during operation, and expressed concerned about theft during construction and possible terrorist attacks during operations, Staff also met with representatives of law enforcement including the Kern County Sheriff's Department, the California Highway Patrol, and the Joint Anti-terrorism Task Force and discussed security requirements for the proposed HECA facility. The goal of the assessments and meeting was to identify the level of security necessary for deterrence and protection from malicious mischief, vandalism, or domestic/foreign terrorist attacks. The level of infrastructure and cyber security needed for the HECA project is dependent upon the threat imposed, the likelihood of an adversarial attack, the likelihood of success in causing a catastrophic event, and the severity of the consequences of that event. The results of the off-site consequence analysis prepared as part of the RMP was used, in part, to determine the severity of consequences of a catastrophic event. Staff also met with the applicant and its consultants and reviewed the security plans proposed by the applicant.

Intentional Destructive Acts

As with any United States energy infrastructure, the proposed HECA Project facilities could potentially be the target of terrorist attacks or sabotage. However, the potential for such attacks on coal-fueled power plants has not been identified as a threat of comparable magnitude to the concerns about the vulnerability of nuclear power plants to terrorist attacks (Behrens and Holt 2005). Although risks of sabotage or terrorism cannot be quantified because the probability of an attack is not known, the potential environmental effects of an attack can be estimated. Such effects may include localized impacts from releases of harmful materials or gases at the HECA project and associated facilities, similar to those that could occur as a result of an accident or a natural disaster. To evaluate the potential impacts of sabotage or terrorism, failure scenarios are analyzed without specifically identifying the cause of failure mechanism. For example, a truck running over an injection wellhead would result in a wellhead failure, regardless of whether this was done intentionally or through mishap. Releases of harmful chemicals can occur due to failure of a component, human error, a combination of both, or from external events such as plane or rail accidents (e.g., delivery of hazardous chemicals to the site), seismic events, or other natural events such as high winds, tornadoes, floods, ice storms, and natural or human-caused fires.

Therefore, the accident analysis conducted for this PSA/DEIS evaluates the outcome of catastrophic events without determining the motivation behind the incident. The accident analyses included potential releases from accidents at the energy center, CO2 pipeline, and injection wells. These accidents could also be representative of the impacts from a sabotage or terrorism event. Release scenarios evaluated included: liquid oxygen tank leaks, pipeline rupture or puncture, and injection well failure as described previously. Evaluations of hypothetical releases indicate the following potential impacts:

- The most likely individuals to be affected by releases from the energy center equipment or tanks are on-site workers. The estimated number of workers during operations is 87 to 115 people, although not all would be present at any given time in proximity to an incident.
- A failure of the liquid oxygen tanks could cause a potential impact to workers due to fires or frostbite. The initial vapor cloud from such a release was estimated to be within the energy center property.
- CO_2 and trace gases could be dispersed into the air and migrate downwind from pipeline ruptures or punctures or injection well failures. The number of individuals from the general population potentially experiencing transient effects from a release event of CO_2 or the trace gases hydrogen sulfide, sulfur dioxide, or sulfur trioxide from the pipeline or injection wells is estimated to be one or less. Under normal operating conditions, the concentration of trace gases are expected to be lower than simulated, in which case there would be no effects from the trace gases to the general public.
- Under the highest consequence scenarios, onsite workers would be the individuals most at-risk of injury or death if near a release at the energy center, pipeline, or injection wells.

As a result of this information and discussions at meetings, staff believes that security would be addressed in a proper and appropriate manner and would be consistent with LORS. In order to ensure that site security is implemented as planned and also that a shipment of hazardous materials to or from the site is not the target of unauthorized access or attack, staff proposes Conditions of Certification **HAZ-6** and **HAZ-7**. These would address both construction security and operation security plans and would require implementation of site security measures consistent with the above-referenced documents. Staff believes that the impacts of sabotage would be similar to that of an accidental release of a hazardous material and thus many of the safety measures employed to address an accidental release would also serve to prevent, control, and mitigate a release caused by an intentional act of sabotage or terrorist attack. Furthermore, staff believes that the level of threat is low due to its remote location.

The security measures required include perimeter fencing and breach detectors, alarms, site access procedures for employees and vendors, site personnel background checks, and law enforcement contacts in the event of a security breach. Site access for vendors shall be strictly controlled. Consistent with current state and federal regulations governing the transport of hazardous materials, hazardous materials vendors will have to maintain their transport vehicle fleet and employ only properly licensed and trained drivers. The project owner will be required, through the use of contractual language with vendors, to ensure that vendors supplying hazardous materials strictly adhere to the U.S. DOT requirements for hazardous materials vendors to prepare and implement security plans (as per 49 CFR 172.802) and to ensure that all hazardous materials drivers are in compliance through personnel background security checks (as per 49 CFR Part 1572, Subparts A and B). The compliance project manager (CPM) may authorize modifications to these measures or may require additional measures in response to additional guidance provided by the U.S. Department of Homeland Security, the U.S. DOE, or the NERC, after consultation with both appropriate law enforcement agencies and the applicant.

ENHANCED OIL RECOVERY FACILITY (EOR)

The Enhanced Oil Recovery (EOR) facility at Occidental of Elk Hills, Inc. (OEHI) is located approximately four miles south of the proposed HECA project site (OXY 2012). Carbon dioxide is a byproduct at HECA and it is proposed to be compressed and delivered by pipeline to the EOR facility where it would be injected in the oil wells to help in the recovery of naturally trapped oil. It is expected to result in the sequestration of approximately three (3) million tons of CO_2 per year during the demonstration phase. This rate of sequestration would also be required for the operational life of the power plant due to the requirements of California law (SB 1368) and the value created by the use of the CO_2 for EOR. The captured CO_2 would be compressed and transported via pipeline to the Elk Hills Oil Field. An additional small amount of the CO_2 produced by the facility would be used to manufacture urea.

The EOR process involves the injection and reinjection of CO_2 to reduce the viscosity and enhance other properties of trapped oil in order to facilitate its flow through the reservoir, improving extraction. During EOR operations, the pore space left by the extracted oil is occupied by the injected CO_2, sequestering it in the geologic formation. EOR operations would be monitored to ensure that the injected CO_2 remains within the formation. (Please see the **Carbon Sequestration And Greenhouse Gas Emissions** section for a more thorough discussion).

Staff met with the environmental and security personnel for Occidental Elk Hills, Inc. and reviewed the hazardous materials that would be used and stored at the EOR site. During operations at the EOR facility, some hazardous materials would be located at the site and would include ~1000 barrels of diesel fuel for an emergency generator and small amounts of chemicals for water treatment. The area is remote with no access to the public. The site would have flow, pressure, and temperature monitoring devices, fire detection system sensing flame, leak detection sensing petroleum products, and have available a fire water supply tank of 1.5 million gallons. The CO_2 pipeline would for the most part be located underground and security at the two parts above ground where valve boxes exist would be surrounded by chain-link fence

Staff concludes that given the small number of hazardous materials and the distance to any public off-site receptor, it is extremely unlikely that any hazardous materials spill at the EOR project site would result in a significant impact to the off-site public. Therefore, staff does not propose any mitigation measures for the EOR component.

CUMULATIVE IMPACTS AND MITIGATION

Staff analyzed the potential for the existence of cumulative impacts. A significant cumulative hazardous materials impact is defined as the simultaneous uncontrolled release of hazardous materials from multiple locations in a form (gas or liquid) that could cause a significant impact where the release of one hazardous material alone would not cause a significant impact. Existing locations that use or store gaseous or liquid hazardous materials, or locations where such facilities might likely be built, were both considered. The nearby area comprises agricultural lands, which frequently use ammonia as a fertilizer and therefore may have mobile ammonia tanks at various locations. Other than these tanks, staff found no existing or proposed facilities within a distance that could possibly contribute to a cumulative impact. Staff believes that while cumulative impacts are theoretically possible, they are not probable because of the many safeguards implemented to both prevent and mitigate an uncontrolled release.

The applicant’s modeling of a worst-case release of aqueous ammonia from the proposed project site predicts that significant levels of ammonia vapors would not occur off-site and therefore no cumulative impacts would be expected even if a nearby mobile ammonia tank would experience an accidental release concurrent with that from the proposed HECA (HECA 2012e, Section 5.12.5). The applicant will develop and implement a hazardous materials handling program for HECA independent of any other projects considered for potential cumulative impacts. Staff believes that the facility, as proposed by the applicant and with the additional mitigation measures proposed by staff, poses a less than significant risk of accidental release that could result in off-site impacts. It is unlikely that an accidental release that has very low probability of occurrence (about one in one million per year) would independently occur at the HECA site and another site at the same time. Therefore, staff concludes that the facility would not contribute to a significant hazardous materials-related cumulative impact.

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Staff concludes that if all proposed conditions were adopted and implemented, the construction and operation of the HECA project would be in compliance with all applicable laws, ordinances, regulations, and standards (LORS) regarding long-term and short-term project impacts in the area of hazardous materials management.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

Comment: A member of the public, in a letter objecting to the Project on July 16, 2012 (TN #66245), included a print out of anhydrous ammonia safety and underlined information specific to health effects that can occur as a result of exposure to this substance, transport of anhydrous ammonia under pressure, and the potential for its escape from transfer hoses or valves, equipment malfunctions and during transportation. The implied question asks what is the potential of an accident occurring involving anhydrous ammonia and what would the effects be to the surrounding area?

Response: Staff examined the proposed storage and use of anhydrous ammonia and has proposed several engineering and administrative controls that, if implemented along with the applicant's proposed controls, would reduce the risk of an impact to the public to less than significant. (Note that since this comment was submitted, the applicant has dropped its plan to transport anhydrous ammonia off-site for sale.)

Comment: AIR (Association of Irritated Residents) provided a status report and data requests in a document dated November 2, 2012 (TN #68076). Residents asked about the dangers of anhydrous ammonia and if it is deadly. Several asked for more information on the possibility of accidents or releases at the project resulting in fatalities to nearby residents or workers, and accidents involving trucks transporting hazardous materials. They asked specifically how safe is it for someone to live or work nearby if there is a release of CO_2 or anhydrous ammonia, and are there other hazardous gases that might be released and cause harm. There was additional concern expressed regarding the potential for materials on-site to cause explosions and what impact that would have on the neighboring area. A question was raised as to whether the chemical factory will produce ammonium nitrate fertilizer and in what quantity and what security will HECA provide for storage and shipping of ammonium nitrate.

Response: Staff assessed these issues and its response can be seen in this section of the PSA/DEIS above.

Comment: The Kern County Public Health Services Department, Environmental Health Division, requested specific mitigation measures be instituted with regards to hazardous materials management (TN #69831, March 6, 2013). Some of the mitigation measures include:

- Crash protection around proposed secondary containment areas;
- Sensors at the site that will sound early notification of an accidental release;
- Compliance with regulations including development of Hazardous Materials Release Response Plan, Chemical Inventory, California Accidental Release Prevention Program (CalARP), underground storage tanks, aboveground petroleum storage tank spill prevention control, Hazardous Materials Business Plan;

- Development of written materials that provide information to residences and businesses within the area of the off-site consequence analysis (OCA) with the findings of the analysis and actions to follow in the event of a release;
- Complete a Process Hazard Analysis (PHA) for all applicable hazardous materials on-site with mitigation measures and issues of concern;
- Documentation of an Emergency Response Plan for accidental release of hazardous materials.

Response: Staff considered all these issues and provides information as follows:

- *Crash protection around proposed secondary containment areas is required by LORS and thus staff felt it was not necessary to include this requirement in a condition of certification;*
- *Sensors and a warning system will be placed at the site. Sensors are required by LORS and staff's proposed Condition **HAZ-3**. An early warning system of an accidental release would be installed pursuant to an agreement between the project owner and the KCFD/KCEHD and staff believes that this type of system is best designed and implemented as part of that agreement. Staff believes that a successful community warning and notification system is one that is developed and implemented as part of a "good neighbor" agreement between HECA, the KCFD, and the community;*
- *Compliance with regulations including development of Hazardous Materials Release Response Plan, Chemical Inventory, California Accidental Release Prevention Program (CalARP), underground storage tanks, aboveground petroleum storage tank spill prevention control, Hazardous Materials Business Plan is required by LORS and would also be required by Condition **HAZ-2**, **HAZ-3,** and **HAZ-9**;*
- *"Development of written materials that provide information to residences and businesses within the area of off-site consequences analysis (OCA) with the findings of the analysis and actions to follow in the event of a release" Staff has recommended preparation of these materials and information because it would not be part of a CEQA analysis and, as stated above, these programs are most successful when developed as part of a "good neighbor" agreement between HECA, the KCFD, and the community. Staff supports the voluntary implementation of such a program;*
- *Completing a Process Hazard Analysis (PHA) for all applicable hazardous materials on-site with mitigation measures and issues of concern is required by LORS for some substances (anhydrous ammonia and nitric acid) and staff proposes to require it for other processes as well in Condition **HAZ-9;***
- *Documentation of an Emergency Response Plan for accidental release of hazardous materials is required by LORS and staff proposes to require it in Conditions **HAZ-2** and **WORKER SAFETY-2**.*

Comment:
Karen Wright very recently commented on the April 17, 2013 fertilizer plant explosion in West, TX. She stated that the proposed HECA facility is planning to "produce large quantities of ammonia and ammonium nitrate" and that after the disaster at the West, TX

fertilizer plant; it would be “a bad idea to produce the same chemicals in California and endanger the citizens”. She requested that the Energy Commission give this matter serious consideration and that “no measure of safety will overcome the risks”.

Response:
It is true that large amounts of anhydrous ammonia would be produced and stored at the proposed HECA facility and that Urea Ammonium Nitrate (UAN) fertilizer would be produced, stored, and shipped off-site if the proposed facility were to be licensed by the Commission and built. However, the processes involved and the fertilizer that would be produced at the HECA facility are not similar to those involved in the accidental explosion at the West, TX fertilizer handling facility. By comparison the West TX plant stored and handled dry (often referred to as “prilled”) ammonium nitrate (AN), a form that has been responsible for nearly all documented AN accidents. At HECA AN would be produced in a process and would only exist as a aqueous solution in a process vessel. While process accidents can occur at AN production facilities as demonstrated by the accident at the TERRA industries facility that occurred in 1994 in Port Neal Iowa, such process accidents are much less frequent than events caused by handling of dry AN.

There are as many as 1,150 small fertilizer plants in Texas alone and the West Fertilizer Company consisted of several buildings and storage tanks. It stored, distributed and blended fertilizers, including large quantities of dry solid ammonium nitrate, for use by farmers around the Central Texas community. There were no sprinklers, no firewalls, no water deluge systems, and safety inspections by federal, state, or local regulatory agencies were rare. Within a four-block area were a school, an apartment complex, a nursing home, and several residential homes. All were either destroyed or severely damaged.

The maximum amount of ammonium nitrate the plant was permitted to store in one container was 90 tons (180,000 pounds) and the most it could legally have on site was 270 tons (540,000 pounds). It appears that between 28 and 34 tons of ammonium nitrate exploded (equivalent to ~20,000 pounds of TNT) and a total of 150 tons were found onsite. It was also authorized to handle and store up to 54,000 pounds of anhydrous ammonia (which did not leak).

The West Fertilizer Company appears to have a history of non-compliance with regulations. In summer 2012, the U.S. Pipeline and Hazardous Materials Safety Administration assessed a $10,000 fine against West Fertilizer for improperly labeling storage tanks and preparing to transfer chemicals without a security plan. The company paid $5,250 after reporting it had corrected the problems. The U.S. EPA also cited the plant for not having an up-to-date Risk Management Plan (RMP). That problem was also resolved, and the company submitted a new plan in 2011. That plan, however, said the company did not believe it was storing or handling any flammable substances and did not list fire or an explosion as a danger. At the time of the preparation of this PSA/DEIS, investigators still do not have a cause for the fire or the explosion but do know that the fire occurred first and suspected causes include an intentional act, an issue with the plant's electrical system, and a golf cart.

In comparison, the proposed HECA facility would also produce and store a large amount of anhydrous ammonia, up to 3.8 million gallons (at 5.15 pounds per gallon that would equate to a maximum of 19.5 million pounds of anhydrous ammonia). However, the means of storage is not similar to storage practice at the West Fertilizer facility. While the precise method of storage at the West Fertilizer site is unknown at this time, it is likely that the 54,000 pounds were stored in pressure tanks. Anhydrous ammonia stored as a liquefied *gas at elevated pressure has high internal energy. The internal energy associated with this stored form of anhydrous ammonia can act as a driving force in an accidental release, which can rapidly introduce large quantities of the material to the ambient air resulting in high down-wind concentrations. A view of the satellite photos taken the year before the blast shows tanks that are similar to the shape and size of typical anhydrous ammonia pressure vessels.*

In contrast, the HECA facility proposes to store anhydrous ammonia in two double-walled tanks (primary containment) which would be surrounded by a secondary containment basin (3-foot high wall) capable of holding the full contents of the tank plus the rainfall associated with a 24-hour 25-year storm. The secondary containment would slope to a drain to allow spilled ammonia to flow into a subsurface sump. Both tanks with their separate secondary containments would then be surrounded with a tertiary containment basin with 4-foot high walls. The anhydrous ammonia in the tanks would also be at near atmospheric pressure as a refrigerated liquid. If a leak or high internal tank pressure occurs, the anhydrous ammonia will first fill the interstitial space between the inner and outer walls of the double-walled storage tank. When the pressure builds up to a certain point, a pressure relief valve at the top of the tank will release ammonia as a vapor and not as a jet release of liquid anhydrous ammonia. Should both walls of the double-walled tank fail or should the piping fail, anhydrous ammonia will flow as a refrigerated liquid into the third line of defense, a concrete containment structure that would allow the refrigerated anhydrous ammonia to flow into a subsurface vault. This type of ammonia storage is both intrinsically much safer and a release would be much better controlled than would be the case in a release from pressurized storage.

Also, the fertilizer involved in the West, TX explosion involved solid ammonium nitrate (AN) while HECA would produce (AN) as an intermediate product used to produce urea ammonium nitrate (UAN) fertilizer. UAN in aqueous solution is intrinsically much safer to handle than dry AN.

Ammonium nitrate is a solid and a strong oxidizing agent and thus can be highly explosive when heated or contaminated. This potential for explosions is well recognized and has prompted the U.S. Department of Homeland Security to regulate ammonium nitrate under the Chemical Facility Anti-Terrorism Standard program (6 CFR Part 27 interim final rule). The West Fertilizer plant could have had as much as 270 tons (540,000 pounds) of solid ammonium nitrate on site.

The fertilizer plant at the proposed HECA project would produce AN only as an intermediate product in the ultimate production of urea ammonium nitrate fertilizer in aqueous (water) solution. Urea ammonium nitrate can also be produced in a solid form but would only exist at HECA in an aqueous solution. When in aqueous solution, UAN is stable and does not pose a high explosion risk. However, evaporating the water from a UAN solution would produce a dry solid consisting of urea and ammonium nitrate posing an explosion risk similar to AN. Thus, precautions must be taken to avoid evaporating the water from this UAN solution. During the manufacturing process, anhydrous ammonia would be combined with nitric acid to produce the intermediate chemical ammonium nitrate. The ammonium nitrate would also be in aqueous solution at a concentration of ~79%. Approximately 25.8 tons (~51,600 pounds) of ammonium nitrate would be produced every hour. A storage tank would contain ~43 tons (~8,600 pounds) which represents about a 100-minute supply at the proposed operation production rate and ~3.2 tons (~6,400 pounds) would exist in system pipes and reactor vessels. Thus, a maximum total of ~ 46.2 tons (~92,400 pounds) of ammonium nitrate would be in the system at any one time. The *entire manufacturing process would take place in a closed system with state of the art process controls. At no time would dry solid ammonium nitrate be produced. In case of a fire, suppression systems would reduce risk to process equipment. This can be contrasted to the West Fertilizer plant which could have had as much as 270 tons (540,000 pounds) of dry solid ammonium nitrate present and had no automated fire detection or suppression systems.*

The following table summarizes the differences between the West Fertilizer plant and the proposed HECA facility.

Table 1 – West Fertilizer / HECA comparison

Issue	***West Fertilizer Plant***	***HECA***
anhydrous ammonia [a] stored in pressurized liquid form	*54,000 lbs liquid*	*---*
anhydrous ammonia [a] in refrigerated liquid form at atmospheric pressure	*---*	*19,500,000 lbs liquid*
ammonia storage tank	*single walled pressure vessel*	*refrigerated double-walled vessel at ambient pressure*
ammonium nitrate in dry solid form	*540,000 lbs*	*---*
ammonium nitrate solution	*---*	*92,400 lbs, intermediate product, in aqueous solution in process vessels*
urea ammonium nitrate (UAN) solution	*---*	*63,000 tons in aqueous solution*
fire protection	*no sprinklers, no fire walls*	*state of the art modern advanced fire detection and suppression systems*
distance to nearest residence	*less than one block*	*approximately 4025 ft. (3/4 mile) from the anhydrous ammonia tank; greater from the fertilizer production facility*
distance to nearest school	*less than 4 blocks*	*1.3 miles from the project boundary; greater distance form the ammonia tank and fertilizer production facility*
distance between AN storage and anhydrous ammonia tank	*estimated at 100 ft.*	*~1025 ft.*
regulatory agency inspections	*appear to have been minimal according to press reports*	*regular inspections and/or oversight during construction, commissioning, and operation by the Energy Commission CPM, the KCFD, the Kern County Environmental Health Service Department, the air district, Cal-OSHA, and the U.S. EPA*

a. Anhydrous (e.g., without water) ammonia is gaseous at room temperature and pressure. However, it is usually stored as a liquid by increasing the pressure and/or refrigerating. Because ammonia is readily miscible in water, ammonia is often stored in aqueous solution (water / ammonia mixture) for ease of handling and storage and improved safety.

CONCLUSIONS

Staff's evaluation of the proposed project (with proposed mitigation measures) indicates that hazardous material use will pose no significant impact to the public. Staff's analysis also shows that there will be no significant cumulative impact. With adoption of the proposed conditions of certification, the proposed project will comply with all applicable LORS. In response to Health and Safety Code, section 25531 et seq., the applicant will be required to develop a Risk Management Plan (RMP). To ensure the adequacy of the RMP, staff's proposed conditions of certification require that the RMP be submitted for concurrent review by the Kern County Environmental Health Services Department (KCEHSD) and by Energy Commission staff. In addition, staff's proposed conditions of certification require the review and approval of the RMP by staff prior to the delivery of any hazardous materials to the facility. Other proposed conditions of certification address the issue of the storage and use of anhydrous ammonia, in addition to site security matters.

Staff recommends that the Energy Commission impose the proposed conditions of certification, presented herein, to ensure that the project is designed, constructed, and operated to comply with all applicable LORS and to protect the public from a significant risk of exposure to an accidental chemical release. If all mitigation proposed by the applicant and staff are required and implemented, the use, storage, and transportation of hazardous materials will not present a significant risk to the public.

Staff proposes ten conditions of certification mentioned throughout the text (above), and listed below. Condition of Certification **HAZ-1** ensures that no hazardous material would be used at the facility except as listed in **Appendix B** of the staff assessment, unless there is prior approval by the Energy Commission compliance project manager. Condition of Certification **HAZ-2** requires that a Hazardous Materials Business Plan (HMBP), a Spill Prevention, Control, and Countermeasure Plan (SPCC Plan), and a Risk Management Plan (RMP) be submitted to the KCEHSD for review and to the CPM for review and approval. Staff believes that an accidental release of hazardous material during transfer to/from a delivery tanker to/from a storage tank is the most probable accident scenario and therefore proposes Condition of Certification (**HAZ-3**) requiring the development and implementation of a safety management plan for the delivery of all liquid or gaseous hazardous materials. The development of a safety management plan addressing the delivery of all liquid or gaseous hazardous materials during construction, commissioning, and operations will further reduce the risk of any accidental release not addressed by the proposed spill-prevention mitigation measures and the required RMP. This plan would additionally prevent the mixing of incompatible materials that could result in toxic vapors. Condition of Certification **HAZ-4** requires that the anhydrous ammonia storage tank be designed to certain specifications. The transportation of hazardous materials is addressed in Conditions of Certification **HAZ-5**. Site security during both the construction and operations phases is addressed in Conditions of Certification **HAZ-6** and **HAZ-7.** The safety of stored hazardous materials on-site during construction is addressed in proposed Condition of Certification **HAZ-8**. **HAZ-9** would require the project owner to prepare and implement the recommendations of a Process Safety Management Plan (PSMP) that includes a Hazard and Operability (HAZOP) Analysis and at least one other hazard analysis plan specifically for the use and storage of anhydrous ammonia, syngas, methanol, molten or liquid sulfur, nitric acid, liquid oxygen/nitrogen storage, and the manufacture, storage, and transport of liquid UAN solution and to obtain the review and signed approval from qualified outside independent experts of all the process safety management evaluations conducted and plans prepared prior to submittal to the CPM for approval. It would also require the development and implementation of a pipeline integrity management plan that is consistent with the U.S. DOT Pipeline and Hazardous Materials Safety Administration (PHMSA) Liquid Pipeline Integrity Management in High Consequence Areas for Hazardous Liquid Operators (49 CFR Parts 195.450 and .452) rule, the recommendations of the U.S. Chemical Safety and Hazard Investigation Board in its report on the August 2, 2012 Chevron Richmond Refinery Fire, and the recommendations of the independent professionals retained. Although these plans and analyses are not necessary for staff to understand and assess the project's impacts under CEQA, staff believes that these plans will identify potential system failures before failure can occur and indicate/implement mitigation to reduce the risk of on-site and off-site consequences to less than significant.

Proposed Condition **HAZ-10** would ensure that tank trucks or rail tank cars leaving the facility with liquid sulfur for distribution and sale would not pose a significant risk to the off-site public if an accidental release occurs by prohibiting the transport vehicle from leaving the facility if the head space about the liquid sulfur contains hydrogen sulfide at a concentration of greater than 2 ppm.

Redundancy of command and control systems is required and staff proposes Condition of Certification **HAZ-11** that would require the project owner to ensure that all redundant command and control systems that are "hard-wired" are placed in separate wiring tracks. And, use of natural gas to "blow" debris from new piping would be prohibited by proposed Condition of Certification **HAZ-12.**

Staff also wishes to note the many data requests filed by the Sierra Club and the community group AIR and thanks them for their input, perspective, and contribution. Staff reviewed the requests and the applicant's responses to these data requests in great detail and although it found them to be informative and interesting, staff chose to focus on the goal of reducing impacts from the project as proposed. Thus, staff has concluded that whatever process refinements could or would be made or whatever root cause of an accidental release existed, the conditions of certification recommended by staff combined with those proposed by the applicant and the adherence to existing LORS would address known contingencies to the greatest extent possible and reduce impacts to a level of less than significance.

Furthermore, as discussed in the **Socioeconomic Resources** section of this PSA/DEIS, the minority population surrounding the project site constitutes an environmental justice population as defined by *Environmental Justice: Guidance Under the National Environmental Policy Act*. Staff has not identified any significant adverse direct or cumulative **Hazardous Materials Management** impacts resulting from the construction or operation of the proposed project, including impacts to the environmental justice population. Therefore, there are no **Hazardous Materials Management** environmental justice issues related to this project and no environmental justice populations would be significantly, adversely, or disproportionately impacted.

PROPOSED CONDITIONS OF CERTIFICATION

HAZ-1 The project owner shall not use any hazardous materials not listed in Appendix B, below, or in greater quantities or strengths than those identified by chemical name in Appendix B, below, unless approved in advance by the compliance project manager (CPM).

Verification: The project owner shall provide to the CPM, in the Annual Compliance Report, a list of hazardous materials contained at the facility, the quantities present, the strengths (concentrations) of solutions, and the locations where they will be stored and used.

HAZ-2 The project owner shall concurrently provide the following to the Kern County Environmental Health Service Department (KCEHSD) and the CPM for review:

a. a Hazardous Materials Business Plan (HMBP);

b. a Spill Prevention, Control, and Countermeasure Plan (SPCC Plan); and

c. a Risk Management Plan (RMP) specifically for the use and storage of anhydrous ammonia, methanol, and liquid oxygen/nitrogen and prepared pursuant to the California Accidental Release Program (CalARP).

After receiving comments from the KCEHSD and the CPM, the project owner shall reflect all recommendations in the final documents. Copies of the final plans shall then be provided to the KCEHSD for information and to the CPM for approval.

Verification: At least thirty (30) days prior to receiving or producing any hazardous material on the site for commissioning or operations, the project owner shall provide a copy of a final Hazardous Materials Business Plan, Spill Prevention, Control, and Countermeasure Plan, a Process Safety Management Plan, and a Risk Management Plan to the CPM for approval. At least thirty (30) days prior to delivery to or production of any hazardous material on the site, the project owner shall provide the final RMP to the CUPA (Certified Unified Program Agency which is the Kern County Environmental Health Service Department) for information and to the CPM for approval.

HAZ-3 The project owner shall develop and implement a Safety Management Plan for the on-site production of or delivery to the site of any liquid, gaseous, or cryogenic hazardous materials. The plan shall include procedures, protective equipment requirements, training, and a checklist. It shall also include a section describing all measures to be implemented to prevent mixing of incompatible hazardous materials including provisions to maintain lockout control by a power plant employee not involved in any delivery or transfer operation. It shall also describe the type, number, locations, and detection limits of hazardous gas monitors for ammonia, carbon monoxide, hydrogen sulfide, and sulfur dioxide. This plan shall be applicable during commissioning and operation of the power plant.

Verification: At least thirty (30) days prior to the production of or delivery to the site of any liquid, gaseous, or cryogenic hazardous material for purposes of commissioning or operation, the project owner shall provide the Safety Management Plan as described above to the CPM for review and approval.

HAZ-4 The two anhydrous ammonia storage tanks shall be double-walled tanks designed to API 620 Appendix R. The storage tanks shall be protected by a secondary containment basin capable of holding 125% of the storage volume and that drains to an underground vault. The final design drawings and specifications for the ammonia storage tanks and secondary containment basin and vault shall be submitted to the CPM for review and approval.

Verification: At least sixty (60) days prior to the planned start of production of anhydrous ammonia, the project owner shall submit final design drawings and specifications for the ammonia storage tanks and secondary containment basin/vault to the CPM for review and approval.

HAZ-5 At least thirty (30) days prior to site mobilization, the project owner shall direct all vendors delivering any hazardous material to the site to use only the route approved by the CPM. Trucks shall travel from Interstate-5 via Stockdale Road, to Morris Road, to Station Road, and to the plant site. The project owner shall obtain approval of the CPM if an alternate route is desired.

Verification: At least thirty (30) days prior to site mobilization, the project owner shall submit to the CPM for review and approval copies of notices to hazardous materials vendors describing the required transportation route.

HAZ-6 Prior to commencing construction, a site-specific Construction Site Security Plan for the construction phase shall be prepared and made available to the CPM for review and approval. The Construction Security Plan shall include the following:

1. perimeter security consisting of fencing enclosing the construction area;
2. security guards;
3. site access control consisting of a check-in procedure or tag system for construction personnel and visitors;
4. written standard procedures for employees, contractors and vendors when encountering suspicious objects or packages on site or off site;
5. protocol for contacting law enforcement and the CPM in the event of suspicious activity or emergency; and
6. Evacuation procedures.

Verification: At least thirty (30) days prior to commencing construction, the project owner shall notify the CPM that a site-specific Construction Security Plan is available for review and approval.

HAZ-7 The project owner shall also prepare a site-specific security plan for the commissioning and operational phases that will be available to the CPM for review and approval. The project owner shall implement site security measures that address physical site security and hazardous materials storage. The level of security to be implemented shall not be less than that described below. Under no circumstances shall chains or padlocks be used to secure any access gate.

The Operation Security Plan shall include the following:

1. permanent full perimeter fence or wall, at least 8 feet high;
2. motorized main entrance and rail car security gates;

3. evacuation procedures;

4. protocol for contacting law enforcement and the CPM in the event of suspicious activity or emergency;

5. written standard procedures for employees, contractors, and vendors when encountering suspicious objects or packages on site or off site;

6. A. a statement (refer to sample, **Attachment A**), signed by the project owner certifying that background investigations have been conducted on all project personnel. Background investigations shall be restricted to determine the accuracy of employee identity and employment history and shall be conducted in accordance with state and federal laws regarding security and privacy;

   B. a statement(s) (refer to sample, **Attachment B**), signed by the contractor(s) or authorized representative(s) for any permanent contractors or other technical contractors (as determined by the CPM after consultation with the project owner), that are present at any time on the site to repair, maintain, investigate, or conduct any other technical duties involving critical components (as determined by the CPM after consultation with the project owner) certifying that background investigations have been conducted on contractors who visit the project site;

7. site access controls for employees, contractors, vendors, and visitors;

8. a statement(s) (refer to sample, **Attachment C**), signed by the owners or authorized representative(s) of each hazardous materials transport vendor accessing the project site, certifying that they have prepared and implemented security plans in compliance with 49 CFR 172.802, and that they have conducted employee background investigations in accordance with 49 CFR Part 1572, subparts A and B;

9. closed circuit TV (CCTV) monitoring system, recordable, cameras able to pan, tilt, and zoom and have low-light capability, and viewable in the power plant control room and security station (if separate from the control room) capable of viewing, at a minimum, the main entrance gate, the rail car entrance gate, any man-gates, the anhydrous ammonia storage tank, the liquid oxygen/nitrogen storage tanks, the entrance to the control room, natural gas and CO2 metering location, 100% of the perimeter fence;

10. security guard(s) present 24 hours per day, 7 days per week; and

11. perimeter breach detectors **<u>or</u>** on-site motion detectors.

The project owner shall fully implement the security plans and obtain CPM approval of any substantive modifications to those security plans. The CPM may authorize modifications to these measures, or may require additional measures such as protective barriers for critical power plant components or cyber security measures depending upon circumstances unique to the facility or in response to industry-related standards, security concerns, or additional guidance provided by the U.S. Department of Homeland Security, the U.S. Department of Energy, or the North American Electrical Reliability Council, after consultation with both appropriate law enforcement agencies and the applicant.

Verification: At least thirty (30) days prior to the initial receipt of any hazardous material on site used for the purpose of commissioning or operations, the project owner shall notify the CPM in writing that a site-specific operations site security plan is available for review and approval. In the annual compliance report, the project owner shall include a statement that all current project employee and appropriate contractor background investigations have been performed and that updated certification statements have been appended to the operations security plan. In the annual compliance report, the project owner shall include a statement that the operations security plan includes all current hazardous materials transport vendor certifications for security plans and employee background investigations.

HAZ-8 The project owner shall prepare management plans and implement the following programs during construction:

1. On-site Vehicle Fueling Plan: The following measures shall be implemented related to fueling and maintenance of vehicles and equipment:

- No smoking, open flames, or welding shall be allowed in the fueling/services areas.
- Servicing and fueling of vehicles and equipment shall occur only in designated areas.
- Fuel storage tanks shall have secondary containment.
- Fueling service and maintenance shall be conducted only by authorized personnel.
- Refueling shall be conducted only with approved pumps, hoses, and nozzles.
- All disconnected hoses shall be handled in a manner to prevent residual fuel and fluids from being released into the environment.
- Catch-pans shall be placed under equipment/hose connections to catch potential spills during fueling and servicing.
- Service trucks shall be provided with fire extinguishers and spill containment equipment, such as absorbents, shovels, and containers.
- Service trucks shall not remain on the job site after fueling and service are complete.

2. Bulk Hazardous Materials Management Plan: Bulk hazardous materials shall be managed as described below:

- The 4,000-gallon diesel storage tank and 4,000 gal gasoline storage tank shall be equipped with secondary containment capable of holding 110 percent of the tank volume.
- The 400 gallons of lubricating oil shall be stored in a tank that shall be equipped with a secondary containment capable of holding 100 percent of the tank volume. Liquid detection equipment shall be installed to detect any potential leaks generated and collected in the secondary containment annular space.

The project owner shall provide to the CPM for review and approval a copy of the Vehicle Fueling Plan and the Bulk Hazardous Materials Management Plan.

Verification: At least thirty (30) days prior to site mobilization, the project owner shall provide the Vehicle Fueling Plan to the CPM for review and approval. At least thirty (30) days prior to the initial receipt of any hazardous material on-site for commissioning or operations, the project owner shall provide the Bulk Hazardous Materials Management Plan to the CPM for review and approval.

HAZ-9 The project owner shall:

a. Conduct process hazard analyses and prepare Process Safety Management Plans (PSM Plans) that includes hazard analyses specifically for the production, use, and storage of anhydrous ammonia, syngas, methanol, molten or liquid sulfur, liquid oxygen/nitrogen, nitric acid, and UAN solution. Such PSM Plans shall contain a hazard analysis using at least two different methodologies. One shall be a Hazard and Operability Study (HAZOP) and the other shall be chosen from the list in 8 CCR 5189 (e) (1) or one that is recognized by engineering organizations or governmental agencies and has the approval of the CPM.

b. Retain an independent outside third party group of professionals to provide peer review and approval of the process hazard analyses and the PSM plans before they are submitted to the CPM. The outside third party shall have expertise in engineering and process operations, shall include at least one member who has experience and knowledge specific to the processes being evaluated, and shall also include one member knowledgeable in the specific process hazard analysis methodologies being used.

c. Develop and implement a pipeline integrity management plan that is consistent with the U.S. DOT Pipeline and Hazardous Materials Safety Administration (PHMSA) Liquid Pipeline Integrity Management in High Consequence Areas for Hazardous Liquid Operators (49 CFR Parts 195.450 and .452) rule, the recommendations of the U.S. Chemical Safety and Hazard Investigation Board in its report on the August 2, 2012 Chevron Richmond Refinery Fire, and the recommendations of the independent professionals retained as per the requirement in section “b” above.

The final report containing the results of the hazard analysis for each process, the final PSM Plan, the pipeline integrity management plan, and the review and approval of the outside third party shall be submitted to the Kern County EHSD and Kern County Fire Department for review and to the CPM for approval.

Verification: At least thirty (30) days prior to receiving any hazardous material on the site for commissioning or operations, the project owner shall provide a copy of a final hazard analysis for each process, the final PSM Plan, the final pipeline integrity management plan, and the review, opinions, and approval of the outside third party to the Kern County EHSD and Kern County Fire Department for review and to the CPM for review and approval.

HAZ-10 The project owner shall ensure through testing that no rail tank car or tanker truck leaving the site with molten or liquid sulfur contains hydrogen sulfide (H_2S) at a concentration greater than 2.0 ppm in the truck or tanker airspace above the sulfur.

Verification: The project owner shall provide to the CPM in the Annual Compliance Report a log of each off-site shipment of molten or liquid sulfur via tanker truck or rail tanker showing the levels of Hydrogen sulfide found in the airspace in the tanker truck or rail tank car.

HAZ-11 The project owner shall make sure that all redundant command and control systems that are "hard-wired" are placed in separate wiring tracks.

Verification: At least thirty (30) days prior to receiving any hazardous material on the site for commissioning or operations, the project owner shall provide detailed plans that describe the command and control systems to the CPM for review and approval.

HAZ-12 The project owner shall not allow any fuel gas pipe cleaning activities on site, either before placing the pipe into service or at any time during the lifetime of the facility, that involve "flammable gas blows" where natural (or flammable) gas is used to blow out debris from piping and then vented to atmosphere. Instead, an inherently safer method involving a non-flammable gas (e.g. air, nitrogen, steam) or mechanical pigging shall be used. Exceptions to any of these provisions will be made only if no other satisfactory method is available, and then only with the approval of the CPM.

Verification: At least 30 days before any fuel gas pipe cleaning activities involving fuel gas pipe of four-inch or greater external diameter, the project owner shall submit a copy of the Fuel Gas Pipe Cleaning Work Plan which shall indicate the method of cleaning to be used, what gas will be used, the source of pressurization, and whether a mechanical PIG will be used, to the CBO for information and to the CPM for review and approval.

Verification: **SAMPLE CERTIFICATION (Attachment A)**

Affidavit of Compliance for Project Owners

I,

____

(Name of Person signing Affidavit)(Title)

do hereby certify that background investigations to ascertain the accuracy of the identity and employment history of all employees of

____

(Company name)

for employment at

____

(Project Name and Location)

have been conducted as required by the California Energy Commission Decision for the above-named project.

____

(Signature of Officer or Agent)

Dated this ____________________ day of ____________________, 20 _______.

THIS AFFIDAVIT OF COMPLIANCE SHALL BE APPENDED TO THE PROJECT SECURITY PLAN AND SHALL BE RETAINED AT ALL TIMES AT THE PROJECT SITE FOR REVIEW BY THE CALIFORNIA ENERGY COMMISSION COMPLIANCE PROJECT MANAGER.

SAMPLE CERTIFICATION (Attachment B)

Affidavit of Compliance for Contractors

I,

____

(Name of Person signing Affidavit)(Title)

do hereby certify that background investigations to ascertain the accuracy of the identity and employment history of all employees of

____

(Company Name)

for contract work at

____

(Project Name and Location)

have been conducted as required by the California Energy Commission Decision for the above-named project.

____

(Signature of Officer or Agent)

Dated this ___________________ day of ___________________, 20 _______.

THIS AFFIDAVIT OF COMPLIANCE SHALL BE APPENDED TO THE PROJECT SECURITY PLAN AND SHALL BE RETAINED AT ALL TIMES AT THE PROJECT SITE FOR REVIEW BY THE CALIFORNIA ENERGY COMMISSION COMPLIANCE PROJECT MANAGER.

SAMPLE CERTIFICATION (Attachment C)

Affidavit of Compliance for Hazardous Materials Transport Vendors

I,

____

(Name of Person signing Affidavit)(Title)

do hereby certify that the below-named company has prepared and implemented security plans in conformity with 49 CFR 172.880 and has conducted employee background investigations in conformity with 49 CFR 172, subparts A and B,

____

(Company Name)

for hazardous materials delivery to

____

(Project Name and Location)

as required by the California Energy Commission Decision for the above-named project.

____

(Signature of Officer or Agent)

Dated this ____________________ day of ____________________, 20 ________.

THIS AFFIDAVIT OF COMPLIANCE SHALL BE APPENDED TO THE PROJECT SECURITY PLAN AND SHALL BE RETAINED AT ALL TIMES AT THE PROJECT SITE FOR REVIEW BY THE CALIFORNIA ENERGY COMMISSION COMPLIANCE PROJECT MANAGER.

REFERENCES

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Hazardous Materials
Appendix A

Basis for Staff's Use of 75 Parts Per Million Ammonia Exposure Criteria

BASIS FOR STAFF'S USE OF 75 Parts Per Million AMMONIA EXPOSURE CRITERIA

Staff uses a health-based airborne concentration of 75 parts per million (PPM) to evaluate the significance of impacts associated with potential accidental releases of ammonia. While this level is not consistent with the 200-ppm level used by the U.S. Environmental Protection Agency and the California Environmental Protection Agency in evaluating such releases pursuant to the Federal Risk Management Program and State Accidental Release Program, it is appropriate for use in staff's analysis of the proposed project. The Federal Risk Management Program and the State Accidental Release Program are administrative programs designed to address emergency planning and ensure that appropriate safety management practices and actions are implemented in response to accidental releases. However, the regulations implementing these programs do not provide clear authority to require design changes or other major changes to a proposed facility. The preface to the Emergency Response Planning Guidelines states that "these values have been derived as planning and emergency response guidelines, **not** exposure guidelines, they do not contain the safety factors normally incorporated into exposure guidelines. Instead they are estimates, by the committee, of the thresholds above which there would be an unacceptable likelihood of observing the defined effects." It is staff's contention that these values apply to healthy adult individuals and are levels that should not be used to evaluate the acceptability of avoidable exposures for the entire population. While these guidelines are useful in decision making in the event that a release has already occurred (for example, prioritizing evacuations), they are not appropriate for and are not binding on discretionary decisions involving proposed facilities where many options for mitigation are feasible. The California Environmental Quality Act requires permitting agencies making discretionary decisions to identify and mitigate potentially significant impacts through feasible changes or alternatives to the proposed project.

Staff has chosen to use the National Research Council's 30-minute Short Term Public Emergency Limit (STPEL) for ammonia to determine the potential for significant impact. This limit is designed to apply to accidental unanticipated releases and subsequent public exposure. Exposure at this level should not result in serious effects but would result in "strong odor, lacrimation, and irritation of the upper respiratory tract (nose and throat), but no incapacitation or prevention of self-rescue." It is staff's opinion that exposures to concentrations above these levels pose significant risk of adverse health impacts on sensitive members of the general public. It is also staff's position that these exposure limits are the best available criteria to use in gauging the significance of public exposures associated with potential accidental releases. It is, further staff's opinion that these limits constitute an appropriate balance between public protection and mitigation of unlikely events and are useful in focusing mitigation efforts on those release scenarios that pose real potential for serious impacts on the public. Table 1 provides a comparison of the intended use and limitations associated with each of the various criteria that staff considered in arriving at the decision to use the 75-ppm STPEL.

Hazardous Materials Appendix A Table 1
Acute Ammonia Exposure Guidelines

Guideline	Responsible Authority	Applicable Exposed Group	Allowable Exposure Level	Allowable* Duration of Exposures	Potential Toxicity at Guideline Level/Intended Purpose of Guideline
IDLH[2]	NIOSH	Workplace standard used to identify appropriate respiratory protection.	300 ppm	30 minutes	Exposure above this level requires the use of “highly reliable” respiratory protection and poses the risk of death, serious irreversible injury, or impairment of the ability to escape.
IDLH/10[1]	EPA, NIOSH	Work place standard adjusted for general population factor of 10 for variation in sensitivity	30 ppm	30 minutes	Protects nearly all segments of general population from irreversible effects.
STEL[2]	NIOSH	Adult healthy male workers	35 ppm	15 minutes, 4 times per 8-hour day	No toxicity, including avoidance of irritation.
EEGL[3]	NRC	Adult healthy workers, military personnel	100 ppm	Generally less than 60 minutes	Significant irritation, but no impact on personnel in performance of emergency work; no irreversible health effects in healthy adults. Emergency conditions one-time exposure.
STPEL[4]	NRC	Most members of general population	50 ppm 75 ppm 100 ppm	60 minutes 30 minutes 10 minutes	Significant irritation, but protects nearly all segments of general population from irreversible acute or late effects. One-time accidental exposure.
TWA[2]	NIOSH	Adult healthy male workers	25 ppm	8 hours	No toxicity or irritation on continuous exposure for repeated 8-hour work shifts.
ERPG-2[5]	AIHA	Applicable only to emergency response planning for the general population (evacuation) (not intended as exposure criteria) (see preface attached)	200 ppm	60 minutes	Exposures above this level entail** unacceptable risk of irreversible effects in healthy adult members of the general population (no safety margin).

1) (EPA 1987) 2) (NIOSH 1994) 3) (NRC 1985) 4) (NRC 1972) 5) (AIHA 1989)

* The (NRC 1979), (WHO 1986), and (Henderson and Haggard 1943) all conclude that available data confirm the direct relationship to increases in effect with both increased exposure and increased exposure duration.

** The (NRC 1979) describes a study involving young animals, which suggests greater sensitivity to acute exposure in young animals. The WHO (1986) warned that the young, elderly, asthmatics, those with bronchitis, and those that exercise should also be considered at increased risk based on their demonstrated greater susceptibility to other non-specific irritants.

REFERENCES FOR HAZARDOUS MATERIALS APPENDIX A, TABLE 1

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ABBREVIATIONS FOR HAZARDOUS MATERIALS APPENDIX A, TABLE 1

ACGIH	American Conference of Governmental and Industrial Hygienists
AIHA	American Industrial Hygienists Association
EEGL	Emergency Exposure Guidance Level
EPA	Environmental Protection Agency
ERPG	Emergency Response Planning Guidelines
IDLH	Immediately Dangerous to Life and Health Level
NIOSH	National Institute of Occupational Safety and Health
NRC	National Research Council
STEL	Short Term Exposure Limit
STPEL	Short Term Public Emergency Limit
TLV	Threshold Limit Value
WHO	World Health Organization

Hazardous Materials
Appendix B

Hazardous Materials Proposed for Use and Storage On-site at HECA

Hazardous Materials Appendix B
Hazardous Materials Proposed for Use and Storage On-site at HECA

Material	CAS No.	Application	Hazardous Characteristics	Maximum Quantity On Site
Ammonium Nitrate Solution (75-85wt%)	6484-52-2	Intermediate, produced/used in UAN Plant	Health: irritant	54 tons
Anhydrous Ammonia (liquid)	7664-41-7	Intermediate, produced in and used in Manufacturing Complex	Health: irritation to permanent damage from inhalation, ingestion, and skin contact Physical: reactive, vapor is combustible	≈10,800 tons (≈7 day usage) (3,800,000 gals)
Boiler Feedwater Chemicals (e.g., Morpholine Cyclohexamine Sodium Sulfite)		Boiler feedwater pH/corrosion / dissolved oxygen/biocide control	Health: Physical: corrosive	< 500 gallons
Chemical Reagents (acids/bases)		Laboratory services	Health: Physical: corrosive, reactive	< 5 gallons
CTG and HRSG cleaning chemicals (e.g., HCl, citric acid, EDTA chelant, sodium nitrate)		HRSG chemical cleaning	Health: toxic Physical: reactive	Intermittent cleaning requirement, temporary storage only
Compressed Gases (Ar, He, H_2)		Laboratory services	Health: Physical: ignitable	Minimal
Degassed Liquid Sulfur		Product	Physical: ignitable, reactive	700 tons
Diesel Fuel	Mixture	Emergency generator/fire water pump fuel	Health: Low-toxicity Physical: ignitable	2,000 gallons
Flammable/Hazardous Gases (CO, H_2S), Syngas and Hydrogen-Rich Fuel		Intermediate product used for power generation and nitrogen-based product generation	Health: toxic Physical: ignitable	In process quantities only, no storage on site
Hydrogen	1333-74-0	STG & CTG generator cooling	Health: low toxicity Physical: ignitable	30,000 standard cubic feet
Methanol		AGR solvent make-up	Health: Physical: ignitable	300,000 gallons
Miscellaneous Industrial Gases – Acetylene, Oxygen, other welding gases, analyzer calibration gases		Maintenance welding/ instrumentation calibration	Health: toxic Physical: ignitable	Minimal

Material	CAS No.	Application	Hazardous Characteristics	Maximum Quantity On Site
Natural Gas	74-82-8	Provides fuel service to consumers	Health: Asphyxiant. Effects are due to lack of oxygen. Physical: ignitable	Utility supply on demand via pipeline
Nitric Acid (≈60wt%)	7697-37-2	Intermediate, produced/used in UAN Plant	Health: irritant Physical: corrosive, reactive	2,600 tons (3 days)
Paint, Thinners, Solvents, Adhesives, etc.		Shop/Warehouse	Health: toxic Physical: ignitable	<20 gallons
Sodium Hydroxide (caustic solution)	1310-73-2	Plant wastewater ZLD, sour water treatment, demineralizers, caustic scrubber, desuperheater contact condenser	Health: causes eye and skin burns, hygroscopic, may cause severe respiratory tract irritation with possible burns, hazardous if ingested Physical: corrosive	150,000 gallons (5-50% wt% NaOH)
Spent Caustic		Intermediate storage pending treatment off-site	Health: toxic Physical: corrosive	150,000 gallons
Sulfuric Acid	7664-93-9	Plant waste water treating, cooling water, BFW pH control, demineralizers	Health: irritant to eyes, poisonous if inhaled, extreme irritant, corrosive, and toxic to tissue Physical: corrosive, reactive	14,000 gallons
UAN Solution		Plant product	Physical: corrosive	63,000 tons (45 days of production)

Source: URS 2012 Table 5.12-3

LAND USE

Jonathan Fong

SUMMARY OF CONCLUSIONS

The Land Use section of the Preliminary Staff Assessment (PSA)/ Draft Environmental Impact Statement (DEIS) analyzes the potential effects that would occur by construction and operation of the proposed Hydrogen Energy California project (HECA or project) on land use and applicable laws, ordinances, regulations and standards (LORS).

Kern County has determined that the HECA project modification to restrict chemical manufacturing to fertilizer for agricultural use only addresses the zoning and general plan compatibility issues previously raised by the county (Kern County 2013a). To ensure compliance with Section 19.12.030.A of the Kern County Zoning Ordinance, Kern County requested staff propose a mitigation measure to restrict the chemical manufacturing to fertilizer for agricultural use only. To address Kern County's concerns, staff proposes Condition of Certification **LAND-6.**

The HECA project would permanently convert prime farmland and farmland of statewide importance, as classified by the California Department of Conservation. To mitigate this significant impact, staff is recommending Conditions of Certification **LAND-1** and **LAND-2.**

While the project would be a conditionally permitted use pursuant to the county zoning ordinance, one finding of approval that must be met is that "the proposed use will not be detrimental to the health, safety, and welfare of the public or to property and residents in the vicinity" (19.104.040(E)). Staff cannot determine this finding can be made until the outstanding information identified in other technical areas is provided. To determine compliance with county development standards, the applicant is required to submit a site plan demonstrating compliance with Sections 19.12.070 (setbacks) and 19.12.100 (parking) of the zoning ordinance.

Socioeconomics Table 2 in the **Socioeconomics** section shows that the population within the six-mile buffer constitutes an environmental justice population as defined by *Environmental Justice: Guidance Under the National Environmental Policy Act*. Staff has concluded that with staff's proposed conditions of certification, the project would have no significant or disproportionate land use impacts on any population, including an environmental justice population.

Staff has reviewed the Occidental of Elk Hills, Inc (OEHI) CO_2 Enhanced Oil Recovery (EOR) component for potential impacts to land use. Staff considers the OEHI component as part of the HECA project and therefore subject to review in accordance with the California Environmental Quality Act (CEQA) and the National Environmental Policy Act (NEPA). Staff concludes the OEHI EOR component would not result in significant direct, indirect, or cumulative adverse land use impacts.

OUTSTANDING ISSUES

For staff to conclude HECA complies with applicable land use LORS, the applicant is required to submit additional information.

To determine project compliance with Sections 19.12.070 and 19.12.100 of the Kern County Zoning Ordianance, staff requests the applicant provide:

- A site plan drawn to scale of all proposed structures demonstrating compliance with the sections of the zoning ordinance cited above.

The project applicant is also required to submit to Kern County an application for cancellation of Williamson Act contracts for the rail spur lands.

INTRODUCTION

This section of the PSA/DEIS focuses on two main issues with the proposed project: consistency with applicable land use LORS and reasonably foreseeable[1] potential impacts to agricultural uses. Staff has evaluated these potential impacts in accordance with the requirements of the National Environmental Policy Act (NEPA) and the California Environmental Quality Act (CEQA), Appendix G "Environmental Checklist Form." A project and related uses would be incompatible with existing and planned land uses if they are inconsistent with applicable LORS or if they cause significant and unmitigated environmental impacts.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

Land Use Table 1 lists the state and local land use LORS applicable to the proposed project and surrounding lands. There are no federal land use LORS applicable to the proposed project and surrounding lands. Compatibility with each LORS is analyzed below, under "Assessment of Impacts and Discussion of Mitigation."

Land Use Table 1
Applicable Laws, Ordinances, Regulations, and Standards (LORS)

Applicable LORS	Description
State	
California Land Conservation Act of 1965 (Gov. Code § 51200-51297.4)	Enabling statute that allows local governments and private land owners to enter into agreements to restrict land uses on specific parcels. Section 51282 addresses Williamson Act Contract cancellation procedures. In order for a contract to be cancelled, the local elected officials (e.g. a City Council or a County Board of Supervisors) need to make a series of findings and approve the cancellation.
Subdivision Map Act (Pub. Resources Code § 66410-66499.58),§ 66412.1	Subdivision Map Act exempts a project from state subdivision requirements provided that the project demonstrates compliance with local ordinances regulating design and improvements.

[1] Reasonably foreseeable" is defined in the California Environmental Quality Act (CEQA) as approved projects under construction; approved related projects not yet under construction; unapproved (planned) projects, with related impacts, currently under environmental review; and projects under review by the Lead Agency or other relevant public agencies. Planned developments, such as those identified in an airport Master Plan, may also be considered, provided there is evidence that measures are actually being taken to implement the plans. The analysis must also take into consideration the most probable development patterns and future activities that are a reasonably foreseeable consequence of the initial project.

Applicable LORS	Description
Local	
Kern County General Plan	The General Plan is a County-wide document which includes land use maps, goals and policies intended to protect resources and encourage economic development in the County.
Chapter 1- Land Use Conservation, Open Space Element, Resource Chapter 1.9 Policy 2	Provides comprehensive, long-range plans, policies, and goals to guide the physical development of the county. This element of the General Plan provides a variety of land uses for economic growth while assuring the conservation of Kern County's agricultural, natural and resource attributes.
Title 19, Kern County Zoning Ordinance, Chapter 19.12 Exclusive Agricultural (A)	This ordinance provides a framework for development by indicating allowable uses and development standards that support the General Plan. This title is adopted to promote and protect the public health, safety, and welfare through the orderly regulation of land uses throughout the unincorporated area of the County.
Title 18, Kern County Land Division Ordinance, Chapter 18.35 Lot Line Adjustments	County ordinance for implementing the California Subdivision Map Act. The purpose of the ordinance is to promote and protect the public health, safety, and welfare through the orderly regulation of land division throughout the unincorporated area of Kern County.

SETTING

PROJECT SITE

The HECA site would be composed of a 453-acre project site and a 653-acre controlled area. The project site encompasses portions of three separate legal parcels: Assessor's Parcel Number 159-040-02 (part), 159-040-16 (part) and 159-040-18 (part). The controlled area includes four separate legal parcels: 159-040-16 (part), 159-040-17, 159-040-18 (part) and 159-0190-09. The site is located in western unincorporated Kern County. Please refer to the **Project Description Section Figures 1 and 2** for a statewide and regional map of the project site. Bakersfield is the nearest incorporated city located approximately seven miles west of the site. Nearby communities include the unincorporated communities of Tupman, two miles southeast of the site, and Buttonwillow four miles northwest of the site. The project site is bounded to the north by Adohr Road and to the west by Tupman Road which provides access to the site. The site is bounded to the south by an existing irrigation canal. The site is currently in agricultural use producing alfalfa, cotton and onions. The controlled area is also currently in use producing the same crops. A portion of the controlled area southeast of the intersection of Dairy Road and Adohr Road is the site of a fertilizer manufacturing plant which is no longer in operation.

The EOR processing facility and satellites would occupy approximately 135.6 acres within the existing Elk Hills Oil Fields which is part of the Elk Hills Unit consisting of approximately 48,000 acres within Kern County. The EOR processing facility would be located approximately five miles south of the proposed HECA project site as shown in **Land Use Figure 1.** The project site is characterized by disturbed and vacant lands within an operating oil field.

LINEAR INFRASTRUCTURE/ OFF-SITE IMPROVEMENTS

In addition to the generating facilities within the project site, the HECA project would also consist of the off-site linear infrastructure. The linear infrastructure is explained and summarized in **Land Use Table 2** below.

The HECA project is proposed with two alternatives related to the transportation of coal to the project site. Alternative 1 would transport coal via a new rail spur connecting the project site to the San Joaquin Valley Railroad (SJVRR) north of the project site. Alternative 2 would transport coal from the Wasco station via truck along established trucking routes in the project vicinity. Please refer to **Project Description Figures 6 and 7** for a map of the proposed rail spur and truck coal transport route.

Land Use Table 2
Disturbed Acreage

Project Component	Approx-Linear Length (miles)	Temporary Disturbance (acres)	Permanent Disturbance (acres)	Prime Agricultural Land (acres)
Project Site	n/a	453	453	453
Controlled Area	n/a	91	0	0
Electrical Transmission	2.1	7	0.15	0.15
PG& E Switching Station	n/a	4	4	4
Natural Gas Linear	13	79	0.23 (metering station)	0.23**
BVWSD well field and process water pipeline	15	90.25	1.15 (areas around well)	0.29
Potable water pipeline	1	1.25	0	0
Railroad Spur	5.3	51.2	38.4	34.77 2.84**
CO_2Pipeline	3.4	29	0.11	0
OEHI EOR	n/a	63.79	63.79	0
Total Permanent Disturbance		Prime: 492.21 acres Statewide Importance: 3.07 acres		

**Farmland of Statewide Importance
Adapted from Revised Table 11-1 (Revised Table 2-1) Disturbed Acreage, Supplemental Responses to CEC Data Requests: Nos A56 and A211.

- **Electrical Transmission.** A new approximately two-mile transmission line would connect the HECA project to the existing Midway – Wheeler Ridge 230kV power lines via a new PG&E switching station. The new transmission line would require the installation of 15 new transmission poles off-site and would be constructed within new transmission line rights-of-way on private property. The switching station would be a four-acre site approximately two miles east of the project site on privately owned land.

- **Natural Gas.** A new approximately 13-mile natural gas interconnection would be made with existing PG&E gas lines north of the project site. The proposed gas line would follow the proposed rail spur north to Highway 58, and then continue east beyond the Highway 58/ Interstate 5 interchange, extending north to connect with existing pipelines.

- **Water Supply.** The HECA project would utilize brackish water as part of the energy generating process and potable water for personnel activities. The brackish water would be supplied via a new 15 mile long supply line and five new offsite wells and installed by the Buena Vista Water Storage District. The new waterline would extend northwest from the project site and would generally follow the existing Westside Canal. Potable water would be supplied from the Kern Water District via a new one mile supply line extending east from the project site.

- **Railroad Spur.** Alternative 1 of the HECA project would propose to deliver coal to the project site via a new five mile industrial spur which would connect the project site to the existing San Joaquin Valley Railroad (SJVRR) north of the project site along Highway 58. The proposed rail spur would be located adjacent to the East Side Canal on private property within new rights-of-way.

- **OEHI Processing Facility, Wells and Pipeline.** In addition to the CO_2 EOR processing facility, the OEHI component would involve the installation of 652 miles of new pipeline which would be installed within previously disturbed areas. Enhanced Oil Recovery would take place at 309 CO_2 injection wells and 411 oil production wells. Of the 720 required wells, 570 are already established. If approved, 150 new wells would be installed.

- **Transmission System Upgrades.** The HECA project would require electrical network modifications including substation upgrades, work at the electrical interconnection, and site and transmission line upgrades. The required modifications and network upgrades would occur within the fenced area of existing substations or on existing PG&E towers and would not result in new land disturbance or land use impacts.

GENERAL PLAN LAND USE

PROJECT SITE

The Kern County General Plan was adopted by the County Board of Supervisors on June 15, 2005 with the most recent revision adopted in September 2009. The project site is not located within any specific plan area or other project area designated by the general plan. The general plan designation on the HECA project site is Intensive Agriculture (8.1), which is defined as appropriate for areas devoted to the production of irrigated crops or other agricultural uses. Compatible uses include a variety of agricultural uses; cattle feed yards, petroleum exploration, and public utility uses. The Kern County Zoning Ordinance classifies the project site as Exclusive Agriculture (A). Permitted uses within the (A) zone include agricultural operations, breeding and raising animals, and limited residential uses. Electrical power generating plants are considered permitted uses subject to approval of a conditional use permit, but for the Energy Commission's authority.

The general plan designation on the OEHI EOR site is Mineral and Petroleum (8.4) which is defined as appropriate for areas devoted to the production of irrigated crops or other agricultural uses. The zoning ordinance classifies the project site as Exclusive Agriculture (A) and Limited Agriculture (A-1).

SURROUNDING AREA

The project site is located in a predominantly agricultural area. Crops in production located within one mile of the site include cotton, alfalfa, and pistachio. Sensitive receptors in the area include six residences located within one mile of the project site. One residence is located within the controlled area and would be vacated prior to construction and operation of the HECA project. The nearest sensitive visual resource area would be the Tule Elk State Natural Reserve which is located approximately 3,800 feet east of the project site. The natural reserve includes an interpretative center and habitat viewing areas along Station Road. South of the project site is the Kern River Flood Control Channel and the West Side Canal. Beyond the channel and canal south of the site is the Elk Hills Oil Field.

The proposed linear infrastructure would be located within an area similar to the project site. The linears would cross predominantly agricultural lands with similar production crops and scattered residences as found within one mile of the project site.

The nearest recreational use within six miles of the project site is the Tule Elk Reserve State Park which is located on Station Road approximately 2,000 feet east of the project site. The park includes a Visitor Center, picnic areas, and a public viewing area.

Lands in the vicinity of the project site are predominantly in active agricultural use. The corresponding general plan land use designations and zoning designations for the offsite linears and infrastructure are included in **Land Use Table 3**.

Land uses in the area surrounding the OEHI component are predominantly oil and gas extraction and production and agricultural uses. As shown in **Land Use Figures 4 and 5** the primary general plan land use designation is 8.4 Mineral and Petroleum and the primary zoning designation is A-1 Limited Agriculture.

Communities located within six miles of the HECA project site and EOR Processing Facility site include Buttonwillow, Tupman, Dustin Acres and Valley Acres. Tupman is located roughly 3 miles to the northeast of the Processing Facility site, while Dustin Acres and Valley Acres are located around 3 miles directly to the south. Other communities located in proximity to the Elk Hills Oil Field (EHOF) include Fellows, Ford City, Maricopa, McKittrick, Taft, Taft Heights, and South Taft. Primary access to the Processing Facility Site would be from the SR 119 and North Access Road (Gate 2) entrance, the Tupman Road and North Access Road (Gate 1) entrance, the Elk Hills Road and Skyline Road (Gates 3 and 4) entrance, and the McKittrick (Gate 5) entrance.

Lands currently irrigated and in agricultural production are found north of the project area near the California Aqueduct. Lands east, south, and west of the project site are under petroleum exploration and production. Visible elements of industry infrastructure are found in the area including rigs, pumps, pipelines and processing facilities.

Recreational areas in the project vicinity include the Tule Elk Reserve State Park to the east and the Buena Vista Park Golf Course to the south. Both recreational areas directly abut the Elk Hills Oil Field but are approximately five miles from the proposed project site.

Land Use Table 3
General Plan Land Use Designations/ Zone District

Project Component	General Plan Land Use Designation	Acreage	Zone District	Acreage
Project Site	Intensive Agriculture (8.1)	453	Exclusive Agriculture (A)	453
Controlled Area	Intensive Agriculture (8.1)	653	Exclusive Agriculture (A)	653
Electrical Transmission	Intensive Agriculture (8.1)	0.17	Exclusive Agriculture (A)	0.17
PG&E Switching Station	Intensive Agriculture (8.1)	4	Exclusive Agriculture (A)	4
Natural Gas Line* (metering station inlet)	Intensive Agriculture (8.1)	0.23	Exclusive Agriculture (A)	0.23
BVWSD well field	Intensive Agriculture (8.1)	0.29	Intensive Agriculture (8.1)	0.29
Rail spur	Intensive Agriculture (8.1) Resource Management (8.5)	33.4 (8.1) 5.2 (8.5)	Exclusive Agriculture (A)	38.6
OEHI CO_2 Pipeline and EOR processing facility	Intensive Agriculture (8.1) Extensive Agriculture (8.3) Mineral and Petroleum (8.4)	14 (8.1) 27 (8.3) 50 (8.4)	Exclusive Agriculture (A) Limited Agriculture (A-1)	36.8 (A) 55.2 (A-1)

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Staff has analyzed the information provided in the Application for Certification (AFC) and has acquired information from other sources to determine consistency of the proposed HECA project with applicable land use LORS and the proposed project's potential to have significant adverse land use-related impacts.

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

Significance criteria used in this document are based on Appendix G of the California Environmental Quality Act (CEQA) Guidelines and performance standards or thresholds identified by Energy Commission staff, as well as applicable LORS utilized by other governmental regulatory agencies. As discussed in the **Executive Summary**, this document analyzes the project's impacts pursuant to both the NEPA and CEQA. The two statutes are similar in their requirements concerning analysis of a project's impacts. Therefore, unless otherwise noted, staff's use of, and reference to, CEQA criteria and guidelines also encompasses and satisfies NEPA requirements for this environmental document.

An impact may be considered significant if the proposed project results in:

- Conversion of Farmland or Forest Land.
    - Conversion of Prime Farmland, Unique Farmland, or Farmland of Statewide or Local Importance (Farmland) as shown on the maps prepared pursuant to the Farmland Mapping and Monitoring Program of the California Resources Agency, to non-agricultural use.[2]
    - Conflict with existing zoning for agricultural use, or a Williamson Act contract.
    - Conflict with existing zoning for, or cause rezoning of, forest land [as defined in Pub. Resources Code §12220 (g)), timberland (as defined by Pub. Resources Code §4526), or timberland zoned Timberland Production (as defined by Gov. Code §51104(g)).
    - Result in the loss of forest land or conversion of forest land to non-forest use.
    - Involve other changes in the existing environment which, due to their location or nature, could result in conversion of Farmland to non-agricultural use[3] or conversion of forest land to non-forest use.
- Physical disruption or division of an established community.
- Conflict with any applicable habitat conservation plan, natural community conservation plan, or biological opinion.
- Conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction, or that would normally have jurisdiction, over the project adopted for the purpose of avoiding or mitigating environmental effects. This includes, but is not limited to, a General Plan, redevelopment plan, or zoning ordinance.
- Result in incremental impacts that, although individually limited, are cumulatively considerable when viewed in connection with other project-related effects or the

[2] FMMP defines "land committed to non-agricultural use" as land that is permanently committed by local elected officials to non-agricultural development by virtue of decisions which cannot be reversed simply by a majority vote of a city council or county board of supervisors.

[3] A non-agricultural use in this context refers to land where agriculture (the production of food and fiber) does not constitute a substantial commercial use.

effects of past projects, other current projects, and probable future projects.[4]

In general, a power plant and its related facilities may also be incompatible with existing or planned land uses, resulting in potentially significant impacts, if they create unmitigated noise, dust, or a public health or safety hazard or nuisance; result in adverse traffic or visual impacts; or preclude, interfere with, or unduly restrict existing or future uses. Staff has not identified any potentially significant umitigable impacts related to Air Quality Public Health or Worker Safety and Fire Protection that would affect land use.

Construction and operation of HECA has the potential to generate increased traffic which would affect existing agricultural land uses in the project area. Additional truck traffic in the area has the potential to affect slow moving agricultural equipment and disrupt transport of crops from agricultural fields. Staff is proposing Conditions of Certification **TRANS-1, 2, and 4** to ensure construction traffic is minimized and impacts to the roadways due to HECA construction and operation would be mitigated to less than significant. Traffic and Transportation staff is requesting additional information regarding the proposed public and private rail crossings before concluding the project would have no significant traffic impacts.

Traffic generated by HECA would result in additional noise which would impact the adjacent Tule Elk State Natural Reserve. The additional noise may impact biological resources found in the reserve as well as public visitors. Staff is recommending Condition of Condition **NOISE-9** which would require either roadway improvements, construction of sounds walls, or reduction in posted speed limits to reduce noise impacts to less than significant. To minimize the impact of steam blows, pile driving, and other loud construction activities over 60 dBA in and around Tule Elk State Natural reserve, staff has proposed Condition of Certification **BIO-6.**

At this time Biological Resources and Visual Resources staff cannot conclude that impacts in these areas have been fully mitigated. As such, Land Use staff cannot conclude that the project would be compatible with existing and planned land uses.

DIRECT/INDIRECT IMPACTS AND MITIGATION

AGRICULTURE AND FOREST

Would the project convert Farmland to non-agricultural use?

In the assessment of impacts to agricultural resources, CEQA Guidelines allow a lead agency to use the California Agricultural Land Evaluation and Site Assessment (LESA) Model. The LESA Model was development as a tool to provide lead agencies an evaluation method in addition to the Environmental Checklist in Appendix G of the CEQA Guidelines. The LESA Model was developed by the California Department of

[4] Cumulative impacts refer to two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts. The individual effects may be changes resulting from a single project or a number of separate projects and can result from individually minor, but collectively significant actions taking place over a period of time (CEQA Guidelines §15355; 40 CFR 1508.7)

Conservation (DOC) and incorporates the Farmland Mapping and Monitoring Program (FMMP) maps. The LESA Model assists lead agencies in determining that potentially significant impacts to agricultural resources can be quantified and consistently evaluated during the environmental review process (Pub. Resources Code, §21095).

The LESA Model is comprised of six factors: two Land Evaluation (LE) factors based on measures of soil resource quality; and four Site Assessment (SA) factors that provide quantitative scores based on project size, water resource availability, surrounding agricultural lands and surrounding protected resource lands. The factors are then weighted and combined resulting in a score based on a 100 point scale. The final score indicates the significance of the potential impact as follows:

- 0 to 39 points is not considered significant;
- 40 to 79 points can be significant based on final scoring threshold;
- 80 to 100 points considered significant.

Energy Commission staff applied the LESA Model to determine the impacts to agricultural resources from development of the project site and the proposed rail spur. Factual data provided by the applicant in the AFC and Kern County Geographic Information System (GIS) data was used in the assessment. The LESA score and analysis of these impacts are included below.

Project Site

Energy Commission staff used the LESA Model to determine whether the conversion of 453 acres of farmland for the project would be significant. The calculated LESA score was 79.065 (staff's LESA worksheet is included in **Land Use Appendix A**). Section IV of the LESA manual provides LESA Model Scoring Thresholds Ranges for agricultural impacts. The calculated score falls within the 60 to 79 point range which is "considered significant unless either LE or SA score is less than 20 points." Staff's Final LESA Score Sheet calculated the LE Factor score as 29.815 and the SA Factor score as 49.25, therefore the impact to agricultural resources would be considered significant and mitigation would be required.

Rail spur

Alternative 1 of the proposed coal delivery method would construct an approximately 5-mile long rail spur which would result in the permanent disturbance of 38.6 acres (HECA 2012e). The rail spur is proposed to be located adjacent to the East Side Canal on private property along existing unpaved agricultural access roads. The rail spur would require a permanent disturbance of 60-foot right of way along the entire stretch of the line from the project site to the tie in with the existing SJVRR rail spur along Highway 58. The 60-foot right of way would require the removal of existing row crops along the entirety of the rail spur. Of the disturbed acreage 2.84 acres are farmland of statewide importance and 34.77 acres would be prime farmland.

Staff used the LESA Model to determine if the conversion of farmlands for the rail spur would be significant. The calculated LESA score was 69.01 (staff's LESA worksheet is included in Appendix A). The calculated score falls within the 60 to 79 point range which is "considered significant unless either LE or SA score is less than 20 points."

Staff's Final LESA Score Sheet calculated the LE Factor score as 28.26 and the SA Factor score as 40.75, therefore the impact to farmland of statewide importance and prime farmland would be considered significant and mitigation would be required.

Offsite Linears

As shown above in **Land Use Table 2, Disturbed Acreage**, offsite infrastructure and linears would include: process and potable water wells, electrical transmission lines and natural gas lines. The permanent disturbance resulting from the construction of the linears would impact 0.23 acre of farmland of statewide importance and 0.52 acre of prime farmland. Due to the small amount of lands impacted from the offsite linears, staff did not conduct a LESA analysis for the impacts to farmland. However, because these impacts to farmlands would be permanent, these impacts are considered significant and mitigation would be required. The OEHI component would include an approximately 3.4-mile long CO_2 pipeline which after construction would not impact or disturb agricultural lands.

Construction Laydown Yard

The conversion of 91 acres of the Controlled Area for a construction laydown area was not considered when using the LESA Model to determine the significance of impacts to agricultural lands. The laydown area would be returned to pre-disturbed conditions after construction of the HECA project. Therefore the laydown area impacts to agricultural use would be temporary and not considered a long-term impact.

PG&E Switching Station

The project would require the construction of a new PG&E switching station which would be the first point of interconnect from the project site to the electrical grid. The four-acre switching station would be located on lands under Williamson Act contract and identified as Prime Farmland. Staff did not conduct a LESA analysis for the switching station due to the relatively small amount of land impacted. However, because these impacts to farmlands would be permanent, these impacts are considered significant and mitigation would be required.

OEHI EOR Processing Facility and Wells

The OEHI component and associated infrastructure would not be located on lands classified by the California Department of Conservation as being prime farmland or of local or statewide importance. The Farmland Mapping and Monitoring (FMMP) maps of the project area classified the project site as "grazing land" or "non agricultural and natural vegetation." Southern portions of the site are classified as "vacant disturbed land." There would be no impact.

Conclusion

Staff considers the conversion of prime farmland and farmland of statewide importance a significant impact. To mitigate the loss of agricultural lands, staff proposes Conditions of Certification **LAND-1** and **LAND-2**. Staff is recommending two separate conditions of certifications for agricultural land mitigation in the event the applicant does not construct the rail spur for the transportation of coal to the project site The proposed conditions of certification would require the project owner to mitigate for the loss of Prime and

Statewide Important Farmland on a 1:1 basis either through the payment of mitigation in-lieu fees to either the Kern County or the California Departrment of Conservation or through security agricultural easements. The payment of in-lieu fees would be based on the appraised value of the impacted prime agricultural lands and farmland of statewide importance. The in-lieu fees would be then used to preserve agricultural lands and contribute to preserving the agricultural character in Kern County. The option available to the applicant would be to secure agricultural easements at a 1:1 ratio for the affected agricultural lands. The lands used to mitigate this impact are to be of similar agricultural quality and located within Kern County. This condition of certification has been used on other Energy Commission siting projects (Avenal, Tesla, Salton Sea, Panoche, and Starwood) where agricultural land has been converted to non-agriculture uses. In Kern County's March 6, 2013 letter to the Energy Commission, county staff has also recommended that the Energy Commission include mitigation of impacted farmlands at a 1:1 ratio. The county further recommended that the mitigation lands be within Kern County (Kern 2013a). Staff concludes that upon implementation of Conditions of Certification **LAND-1** and **LAND-2** the impact to farmland would be less than significant. There would be no impact to farmland associated with the OEHI EOR portion of the project.

Would the project conflict with existing zoning for agricultural use?

With the exception of Sections 19.12.070 and 19.12.100 of the Zoning Ordinance, which have yet to be determined because staff needs more information from the applicant, the project would not conflict with existing zoning for agricultural use. Please refer to the discussion in the "Compliance with LORS, Kern County General Plan" and "Title 19 Kern County Zoning Ordinance" subsections below for a determination of the project consistency with the Kern County General plan and zoning.

Would the project conflict with existing Williamson Act contracts?

The California Land Conservation Act, commonly referred to as the Williamson Act, enables local governments to enter into contracts with private landowners for the purpose of restricting specific parcels of land to agricultural or related open space uses. (Chapter 7, Agricultural Land, Gov. Code § 51200-51297.4) The 453-acre project site is currently under Williamson Act contract. The applicant has agreed with concurrence from Kern County Planning and California Department of Conservation (DOC) staff to cancel the Williamson Act contracts on the project site (HECA 2012e).

Cancellation of the Williamson Act contract requires approval by the Kern County Board of Supervisors, following a public hearing and the making of certain findings discussed below. In order to grant tentative approval for cancellation of a Williamson Act contract, Government Code section 51282(a) requires the Kern County Board of Supervisors to make one of the following findings:

- The cancellation is consistent with the purposes of the Williamson Act.
- The cancellation is in the public interest.

County planning staff estimates the contract cancellation application to be scheduled for Planning Commission review on June 13, 2013 with final determination to be made by the Board of Supervisors thereafter.

The HECA project would also include offsite linears which would primarily be located on lands under Williamson Act contract. The “Agricultural Preserve Standard Uniform Rules” is a compilation of Resolutions of the Kern County Board of Supervisors adopting standards generally applicable to all Williamson Act contracts within the county. These Uniform Rules govern the administration of the Williamson Act and establish approved agricultural and compatible uses on contracted lands. The County Uniform Rules allow “[t]he erection, construction, alteration, operation and maintenance of gas, electric, water, and communication utility facilities and similar public service facilities by corporations and companies under the jurisdiction of the Public Utilities Commission of the State of California and by public agencies.” The proposed switching station and electrical, process and potable water, and gas lines would fall under the Uniform Rules as compatible uses with Williamson Act contracted lands. However, Kern County has determined that the rail spur would not be a compatible use pursuant to the Williamson Act and would require cancellation of those affected contracts. At this time, Kern County has not indicated that the applicant has submitted an application for cancellation of the rail spur lands.

The proposed construction laydown area would be located on Williamson Act contracted lands. Kern County Planning and Department of Conservation staffs have determined that construction impacts would be temporary and would not require cancellation of the existing Williamson Act contracts.

The OEHI processing facility, wells, and new pipeline would not be located on lands under Williamson Act contract; there would be no impact to Williamson Act contracts for this portion of the project.

Conclusion

Proposed Conditions of Certification **LAND-3** and **LAND-4** would require the project owner to submit proof of cancellation of the Williamson Act contracts to the Compliance Project Manager (CPM) 60 days prior to start of any construction activities for the HECA project. Upon cancellation of the Williamson Act contracts, impacts would be less than significant.

Would the project conflict with existing zoning for, or cause rezoning of, forest land (as defined in Pub. Resources Code §12220(g)), timberland (as defined by Pub. Resources Code §4526), or timberland zoned Timberland Production (as defined by Gov. Code §51104(g))?

The proposed HECA project site, laydown area and OEHI component are not zoned for forest land, timberland, or for timberland production. In addition, there is no land zoned for such purposes within one mile of the project site. Therefore, there would be no conflict with, or cause for, rezoning of forest land or timberland and as a result there would be no impact to forest land or timberland.

PHYSICAL DISRUPTION OR DIVISION OF AN ESTABLISHED COMMUNITY

Would the project divide an established community or disrupt an existing or recently approved land use?

The HECA project site and linears would be located within an active farming community. The project site as designed would not divide the existing community or disrupt access to parcels in the surrounding area. The proposed water, natural gas and CO_2 linears would be buried upon installation and would not pose a land use impact to the surrounding community.

The proposed electrical transmission line would be constructed along existing private roads and would be installed on transmission poles 90-115 feet tall. The location and design of the transmission poles would allow for unobstructed access to existing roads and would not disturb vehicular access or the movement of agricultural machinery under the transmission line.

The proposed rail spur would be located on privately owned lands and would generally follow the East Side Channel and then parallel Dairy Road to the project site. As shown in **Traffic and Transportation Figures 1-3,** the applicant has proposed two public at-grade crossings at Stockdale Highway and six private at-grade crossings. If the rail spur is constructed as proposed, the public and private at-grade crossings would allow for the movement of vehicles and agricultural machinery across the rail spur at the identified crossings, which would result in a less than significant impact to the community in the area.

The OEHI EOR component is not located within an established community. The proposed EOR processing facility, new injection wells and pipeline would all be constructed on vacant or previously disturbed lands within the Elk Hills Oil Field. There are no recently approved land uses in the area that would be disrupted by the construction or operation of the OEHI component. There would be no impact to any existing communities as a result of this part of the project.

Staff concludes that upon the construction of the public and private crossings on the proposed rail spur, the HECA project and linears would not disrupt or divide the existing community and impacts would be less than significant.

CONFLICT WITH ANY APPLICABLE LAND USE PLAN, POLICY OR REGULATION

Would the project conflict with any applicable land use plan, policy, or regulation?

Please refer to the discussion in the “Compliance with LORS, Kern County General Plan” and “Title 19 Kern County Zoning Ordinance” subsections below for a determination of the project consistency with the Kern County General Plan and Zoning Ordinance.

CONFLICT WITH ANY APPLICABLE HABITAT OR NATURAL COMMUNITY CONSERVATION PLAN

Would the project conflict with any applicable habitat conservation plan (HCP) or natural community conservation plan (NCCP)?

There are no adopted HCPs or NCCPs that would be affected by the HECA site, project linears or the OEHI component. Staff concludes there would be no impact.

COMPLIANCE WITH LORS

As required by California Code of Regulations, Title 20, section 1744, Energy Commission staff evaluates the information provided by the applicant in the form of the AFC (and any supplements). Staff reviews project design and operational components to determine if elements of the proposed project would conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the project, or that would normally have jurisdiction but for the exclusive permitting authority of the California Energy Commission (Pub. Resources Code, § 25500). As part of the licensing process, the Energy Commission must determine whether a proposed facility complies with all applicable federal, state, regional and local LORS (Pub. Resources Code,§ 25523[d][1]). The Energy Commission must either find that a project conforms to all applicable LORS, either by design or with the implementation of appropriate conditions of certification, or make specific findings that a project's approval is justified even where the project is not in conformity with all applicable LORS (Pub. Resources Code,§ 25525). When determining LORS compliance, staff is permitted to rely on a local agency's assessment of whether a proposed project would be consistent with that agency's zoning and general plan. For past projects, staff has requested that the affected local agency provide a discussion of the findings and conditions that the agency would make when determining whether a proposed project would comply with that agency's LORS, were they the permitting authority.

Kern County General Plan

The Land Use, Open Space, and Conservation (Land Use) Element of the Kern County General Plan adopts a land use map that includes land use designations for all parcels within the unincorporated portions of Kern County. The adopted land use designations establish anticipated land use policies, which are further defined and implemented by standards within the zoning ordinance. The general plan land use designations and zone districts for the project site and off-site linears are identified in **Land Use Table 3** above. The predominant land use designation for the project site and the project linears is Exclusive Agriculture (8.1).

The purpose of this chapter of the general plan is to provide policy direction to allow for future economic growth within the County while also protecting natural, agricultural and resource attributes. The General Plan Land Use Map designates the project site as Map Code 8.1 (Intensive Agriculture) which is one of five resource designations established by the General Plan. The Resource land use designation is designed to encourage safe and orderly energy development within the county, including research and demonstration projects, and to become actively involved in the decision and actions of other agencies as they affect energy development in Kern County.

The County Map Code 8.1 designation is defined as areas devoted to the production of irrigated crops or having a potential for such use. Other agricultural uses, while not directly dependent on irrigation for production, may also be consistent with the intensive agriculture designation. The minimum parcel size is 20 acres gross. In addition to agricultural land uses, allowed uses include but are not limited to: “…. public utility uses; and agricultural industries pursuant to provisions of the Kern County Zoning Ordinance, and land within development areas subject to significant physical constraints.”

General Plan Resource Policy 2 states that in areas with a resource designation on the General Plan map, only industrial activities which directly and obviously relate to the exploration, production, and transportation of the particular resource will be considered to be consistent with this General Plan. This policy is implemented in the Zoning Ordinance in Section 19.12.030(A)(2) which conditionally permits fertilizer manufacturing for agricultural uses only.

The initial AFC submitted by the applicant included a chemical manufacturing complex which would produce products for agricultural, transportation and industrial uses (HECA 2012e). Kern County provided response letters in June and July of 2012 stating that such a manufacturing complex would constitute an industrial land use and would require a General Plan Amendment to a compatible land use designation (Kern County 2012d, Kern County 2012e). To address this issue, the applicant revised the project to restrict production of "nitrogen-based products" (including urea, urea ammonium nitrate and anhydrous ammonia) to manufactured products for the purpose of "fertilizer manufacture and storage for agricultural use only." (HECA 2012jj).

The March 6, 2013 Kern County Planning Department letter stated the revised project description to restrict the chemical manufacturing and storage of fertilizers for agricultural use only, would comply with the Kern County General Plan and Zoning Ordinance (Kern 2013a). Kern County staff recommends that if approved by the Energy Commission, the project “include Mitigation Measure(s) to restrict the items produced on site and in the Manufacturing Complex to "fertilizer manufacture and storage for agricultural use only" per Section 19.12.030.A of the Kern County Zoning Ordinance.” Staff is recommending Condition of Certification **LAND-6** which would restrict the products produced from the chemical manufacturing complex to fertilizer for agricultural use only.

With implementation of Condition of Certification **LAND-6** the HECA project would be consistent with the General Plan and Section 19.12.030.A of the Kern County Zoning Ordinance.

The OEHI component would comply with the Kern County General Plan and Zoning Ordinance. The 8.4 Mineral and Petroleum land use designation establishes that oil exploration and production are compatible uses with the 8.4 land use designation. As discussed above, the OEHI component would be directly related to petroleum exploration through the EOR process.

Portions of the project site include the 2.1 (Seismic Hazard) and 2.4 (Steep Slope) overlay due to the topography of lands within the EHOF. These overlays include additional requirements by the permitting agency prior to issuing site development permits for construction of the processing facility. Please refer to the **Facility Design** section for a discussion of project conformance with these Kern County LORS. Staff is recommending Condition of Certification **GEN-1** which would require the project be designed and built to comply with county LORS.

The Kern County Zoning Ordinance includes an Oil and Gas Production Chapter (Chapter 19.98). The chapter establishes that wells for the exploration or production of oil are permitted by right within the Exclusive Agriculture (A) and Limited Agriculture (A-1) zone subject to conformance with applicable state law. The A and A-1 zones establish that uses permitted by right include oil and gas exploration and production. The proposed processing facility is considered an accessory use to a permitted use (oil and gas production) and would also be permitted within the A and A-1 zones.

As proposed, the OEHI component would not conflict with applicable LORS, therefore staff concludes impacts to land use would be less than significant.

<u>Title 18, Kern County Land Division Ordinance</u>

The purpose of the Kern County Land Division Ordinance is to promote and protect the public health, safety and welfare through the orderly regulation of land divisions in the County. The proposed lot line adjustment would be subject to approval by the Planning Director based on the required findings in Section 18.35.060(c).

The project site is comprised of portions of three separate legal parcels. Portions of Assessor's Parcel Number 159-040-16 and 159-040-18 are included in both the project site and controlled area. The proposed lot line adjustment would result in a single 453-acre parcel encompassing the entire project site area. The site area is shown as Intensive Agricultural (8.1) on the General Plan Land Use Map. The HECA project site is not located within any applicable specific plan or rural community plan areas. The project site is located within the Exclusive Agriculture (A) Zone District. The resulting parcel configuration would meet minimum lot size and setback requirements of the A zone district. Condition of Certification **LAND-5** would require the applicant submit to the CPM proof of recordation of the lot line adjustment with the County Recorder's Office.

<u>Title 19, Kern County Zoning Ordinance</u>

The project site is located within the A zone district. Section 19.12.030 of the zoning ordinance permits electrical power generating plants within the A zone subject to approval of a conditional use permit. Kern County's March 6, 2013 letter states that the revised project, which would restrict the chemical manufacturing complex to fertilizer for agricultural use only, would be compatible with uses in the A Zone District. The Kern County Zoning Ordinance (section 19.12.030.A) lists "fertilizer manufacture and storage for agricultural use only" as a conditionally permitted use in the A District. To ensure compliance with the zoning ordinance, staff proposes Condition of Certification **LAND-6** to restrict the sale of fertilizer for agricultural use only**.**

Section 19.104.040(A-E) of the zoning ordinance establishes required findings of approval for conditionally permitted uses. But for the exclusive permitting authority of the Energy Commission, the approving authority is required to find that:

A. The proposed use is consistent with the goals and policies of the applicable General or Specific Plan.

B. The proposed use is consistent with the purpose of the applicable district or districts.

C. The proposed use is listed as a use subject to a conditional use permit in the applicable zoning district or districts or a use determined to be similar to a listed conditional use in accordance with the procedures set out in Sections 19.08.030 through 19.08.080 of this title.

D. The proposed use meets the minimum requirements of this title applicable to the use.

E. The proposed use will not be materially detrimental to the health, safety, and welfare of the public or to property and residents in the vicinity.

While the project would meet zoning requirements with a conditional use permit, it is unclear whether or not the project is fundamentally compatible with existing land uses and if finding 19.104.040(E) can be met. Staff cannot reach a conclusion on this issue until the outstanding information identified in the technical areas requesting such information is provided.

The Kern County Zoning Ordinance divides the unincorporated area of the county into zone districts. The ordinance identifies permitted uses and established development standards in the districts. The adopted zoning designations for the project site and linears are included in **Land Use Table 3**. The entire project site is located in the Exclusive Agriculture (A) Zone District. Chapter 19.12 of the Zoning Ordinance establishes development standards and permitted uses. An analysis of the project's compatibility with these standards is included below:

<u>19.12.050 Minimum Lot Size:</u> The minimum lot size in the A zone is 2 1/2 acres. Following approval and recordation of the lot line adjustment, the project site parcel would be 453 acres and would be consistent with this requirement.

<u>19.12.060 Minimum Lot Area per Dwelling Unit:</u> Because the existing on-site residences would be demolished as part of the project this section of the Zoning Ordinance would not be applicable to the project.

<u>19.12.080 Height Limit:</u> Because the A Zone District does not place any height restrictions on non-residential structures the project would be consistent with this section of the Zoning Ordinance.

<u>Sections 19.12.070 and 19.12.100</u>: These sections of the zoning ordinance establish setback and parking standards for projects within the A Zone District. In order for staff to determine compliance with these LORS staff is requesting the applicant submit a site plan demonstrating compliance with these requirements.

Staff will address the project's compliance with the applicable development standards and conclude if the project meets the required conditional use permit findings of approval prior to publication of the Final Staff Assessment/Final Environmental Impact Statement (FSA/FEIS).

As shown in **Land Use Table 3**, the offsite linears would be located within the Exclusive Agriculture (A) and Limited Agriculture (A-1) Zone Districts. The offsite linears would be permitted by right within the A and A-1 zones.

The OEHI site and associated infrastructure would be located on lands in the Exclusive Agriculture (A) and Limited Agriculture (A-1) Zone District. Section 19.14.020E of the Kern County Zoning Code establishes that oil exploration and production are permitted uses with the A and A-1 zones. There would be no conflict with the existing zoning as part of the OEHI component.

Land Use Table 4
Project Compliance with Adopted and Applicable LORS

Applicable LORS	Description	Consistency Determination	Basis for Consistency
State			
California Subdivision Map Act	Governs the creation, recognition, consolidation/ reconfiguration, adjustment and elimination of parcels of land within California.	Yes, as conditioned	The project will require a Lot Line Adjustment to create a single parcel for the project site.
California Land Conservation Act (Williamson Act)	Enables local governments to enter into contracts with land owners to restrict parcels for agriculture or open space use in return for lower assessed property taxes.	Yes, as conditioned	The project will require cancellation of the existing Williamson Act contracts on the project site and related non-compatible uses.
Local			
Kern County General Plan	Provides comprehensive, long-range plans, policies and goals to guide development within the County.	Yes	Electrical generating facilities are allowed within the 8.1 General Plan Land Use Designation. The project, as revised would comply with the general plan designation.
Resource Chapter 1.9 Policy 2	Industrial uses are permitted only when directly related to the resource.	Yes	The project, as revised, would produce fertilizer for agricultural use only and is therefore consistent with this policy.
Title 18 Kern County Land Division Ordinance	Implementing County Ordinance of the California Subdivision Map Act.	Yes, as conditioned	The project will require a Lot Line Adjustment to create a single parcel for the project site.
Chapter 18.35 Lot Line Adjustments, 18.35.060(C)1	Prior to approval of a lot line adjustment the county is required to find the adjustment is consistent with the General Plan and Zoning ordinance and will not negatively affect the health, safety and welfare of the public at large.	Yes	The proposed Lot Line Adjustment will merge three existing parcels into a single parcel for the project site. This would comply with applicable General Plan policies and Zoning Ordinance requirements.
Title 19 Kern County Zoning Ordinance, Chapter 19.12 Exclusive Agriculture (A)	Implementing ordinance of the General Plan, established uses and development standards within adopted zoning districts.	Undetermined	Electrical generating facilities and fertilizer manufacturing for agricultural uses are conditionally permitted uses within the A zone.

Land Use Table 4
Project Compliance with Adopted and Applicable LORS

Applicable LORS	Description	Consistency Determination	Basis for Consistency
			Land Use staff cannot determine the required conditional use permit findings can be made until the outstanding information identified in other technical areas have been provided. Staff will make this determination prior to publishing the FSA/ FEIS.
19.12.020(D) PERMITTED USES.	UTILITY AND COMMUNICATION FACILITIES. Transmission lines and supporting towers, poles, and underground facilities for gas, water, electricity, telephone, or telegraph service owned and operated by a public utility company or other company under the jurisdiction of the California Public Utilities Commission pursuant to Section 19.08.090 of this title.	Yes	The proposed off-site linears (wells, waterlines, electrical transmission lines, switching station, and natural gas lines) would be permitted by right within the A zone district.
19.12.030 USES PERMITTED WITH A CONDITIONAL USE PERMIT.	AGRICULTURAL USES. Fertilizer manufacture and storage for agricultural use only.	Undetermined	As discussed above, outstanding information has been identified that will need to be provided prior to determining the project meets the findings of approval for conditional use permits.
	RESOURCE EXTRACTION AND ENERGY DEVELOPMENT USES. Electrical power generating plant.	Undetermined	
19.12.070 YARDS AND SETBACKS	Front Yard: 55 feet from centerline of existing or proposed street. Side: 5 feet or 10 feet on corner lots. Rear: 5 feet	Undetermined	Staff will require the applicant submit a site plan demonstrating compliance with these requirements prior to publishing the FSA/ FEIS.
19.12.100 PARKING	Parking shall be in accordance with Chapter 19.82 (Off-Street Parking) of the Zoning Ordinance	Undetermined	

Cumulative Land Use Effects

A project may result in a significant adverse cumulative impact where its effects are cumulatively considerable. "Cumulatively considerable" means that the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects. To analyze the cumulative effect of the project with reasonably foreseeable projects, section 15130(b) of the CEQA Guidelines allows a lead agency to analyze cumulative impacts by either:

(A) A list of past, present, and probable future projects producing related or cumulative impacts, including, if necessary, those projects outside the control of the agency, or

(B) A summary of projections contained in an adopted local, regional or statewide plan, or related planning document, that describes or evaluates conditions contributing to the cumulative effect.

The cumulative land use and planning analysis considers past, current and probable future projects within Kern County that would contribute to cumulative land use impacts by converting agricultural lands to non-agricultural uses. The identified projects are listed in **Land Use Table 5 Cumulative Projects** below**:**

Land Use Table 5
Cumulative Projects

Project	Project Description	Conversion of Ag Land	Mitigation of Ag Land	Status of Project
FRV Orion Solar Project	20 MW solar photovoltaic project	158 acres prime 118 acres statewide	1:1 mitigation	3/2012 DEIR
Pioneer Green Solar Project	125 MW solar photovoltaic project	234 acres important farmland	1:1 mitigation	12/2012 DEIR
FRV Valley Solar Project	115 MW solar photovoltaic project	90 prime 70 acres statewide	1:1 mitigation	11/2012 DEIR
Old River Solar Project	20 MW solar photovoltaic project	234 acres prime	1:1 mitigation	BOS Approved 11/13/2012
Kingbird Solar Photovoltaic Project	40 MW photovoltaic project	324 acres prime	Unknown	3/27/2012 NOP
Valley Solar Projects	48 MW solar photovoltaic project	40 acres prime	1:1 mitigation	Approved 2/9/2012
Willow Springs Solar Project	160 MW solar photovoltaic project	1,402 acres prime	Unknown	3/8/2010 NOP
Rosamond Solar Project	155 MW solar photovoltaic project	1,177 acres prime	Unknown	3/8/2010 NOP
RE Distributed Solar Project	174 MW solar photovoltaic project	315 acres prime	None	Withdrawn 1/24/2012
Maricopa Sun Solar Project	700 MW solar photovoltaic project	6,047 acres roll out of Williamson Act	None	BOS Approved 3/29/2011
Beech Ave Industrial Park Project	Industrial Use Specific Plan	78 acres prime agricultural land	1:1 mitigation	BOS approved 6/2010
Antelope Valley Solar	650 MW solar photovoltaic project	4,379 acres prime, 22 acres statewide	1:1 mitigation	BOS Approved 3/12/2012
Reina Ranch Project	253 single-family homes	76 acres prime	1:1 mitigation	7/2009 FEIR

MW: Megawatt
DEIR: Draft Environmental Impact Report NOP: Notice of Preparation
BOS: Kern County Board of Supervisors FEIR: Final Environmental Impact Report

Agriculture Conversion

The projects listed in **Land Use Table 5** have cumulatively converted approximately 8,700 acres of classified farmland to non-agricultural uses. Staff is proposing conditions of certification **LAND-1** and **LAND-2** to mitigate the direct impacts of HECA's conversion of about 458 acres of agricultural land. With implementation of the proposed conditions of certification, HECA would not contribute to cumulative impacts in this area.

Please note that the majority of the agricultural conversion in Kern County is due to solar photovoltaic renewable energy projects. The Kern County Board of Supervisors adopted a Renewable Energy Goal on February 22, 2011 as a means to produce 10,000 MW of renewable energy by 2015. Kern County has permitted 7,885 MW of renewable energy with an additional 3,200 MW in process (Kern 2013a). As part of the anticipated development, the Kern County General Plan EIR includes an override for the loss of agricultural lands. While the conversion of agricultural lands to non-agricultural uses in Kern County is significant, it is consistent with the 2011 Renewable Energy Goal to produce 10,000 MW of renewable energy by 2015.

Forestland Conversion

The project as proposed does not have any impacts to forest lands or conflict with any land that is zoned for forestland purposes and therefore, does not contribute to cumulative impacts related to this land use area.

Physical Disruption or Division of an Established Community

The project would not significantly disrupt the surrounding agricultural community. There would be no direct impacts, therefore the project would not contribute to cumulative impacts to this land use area.

Conflict with any Applicable Habitat or Natural Community Conservation Plan

The project would not conflict with any habitat or natural community conservation plans and would not contribute to any cumulative impacts in this land use area.

Conflict with Any Applicable Land Use Plan, Policy or Regulation

With the exception of compliance with Sections 19.12.070 and 19.12.100 of the zoning ordinance and the required findings of approval for conditional use permits, which have yet to be determined, the HECA project would not conflict with applicable LORS and would not contribute to cumulative LORS conflicts. The OEHI project would not contribute to cumulative LORS conflicts.

FACILITY CLOSURE

At some point in the future, the proposed power plant facility would permanently cease operation and close down. At that time, it would be necessary to ensure that closure is carried out in such a way that public health, safety and the environment are protected from adverse impacts.

The AFC states the planned lifetime of the plant is 25 years; however, if the plant is still economically viable, it can operate longer. It is also possible that the plant could become economically noncompetitive earlier than 25 years and be permanently closed earlier. When the plant is permanently closed, a decommissioning plan would be developed detailing the closure procedure to ensure that public health, safety and the environment are protected. At least 12 months prior to decommissioning, the applicant would prepare a Facility Closure Plan for Energy Commission review and approval. The review and approval process would be publicly noticed and allow participation by interested parties and other regulatory agencies, including Kern County. At the time of closure, all pertinent LORS would be identified and the closure plan would discuss conformance of decommissioning, restoration, and remediation activities with these LORS. All of these activities would be under the authority of the Energy Commission. There are two other circumstances in which a facility closure can occur; unplanned temporary closure or unplanned permanent closure.

An unplanned temporary closure occurs when the facility is closed suddenly and/or unexpectedly, on a short-term basis, due to unforeseen circumstances such as a natural disaster or an emergency. An unplanned permanent closure occurs if the project owner closes the facility suddenly and/or unexpectedly, on a permanent basis. An on-site contingency plan will be required (see **Compliance Conditions** section of the PSA/DEIS) to ensure that all necessary steps to mitigate public health and safety impacts and environmental impacts are taken in a timely manner for such unexpected events.

NOTEWORTHY PUBLIC BENEFITS

Staff has not identified any noteworthy public benefits related to land use.

DOE’S FINDINGS REGARDING DIRECT AND INDIRECT IMPACTS OF THE NO-ACTION ALTERNATIVE

Under the No-Action Alternative, DOE would not provide financial assistance to the Applicant for the HECA Project. The Applicant could still elect to construct and operate its project in the absence of financial assistance from DOE, but DOE believes this is unlikely. For the purposes of analysis in the PSA/DEIS, DOE assumes the project would not be constructed under the No-Action Alternative. Accordingly, the No-Action Alternative would have no impacts associated with this resource area.

RESPONSE TO PUBLIC AND AGENCY COMMENTS

Energy Commission staff has received the following comments on the HECA project related to land use:

ASSOCIATION OF IRRITATED RESIDENTS (AIR)

Thomas Frantz, President of AIR submitted a status report and data request to the Energy Commission which included data requests related to land use and agriculture (AIR 2012a). These data requests include issues related to agricultural land mitigation As discussed in this PSA/DEIS, staff is recommending Conditions of Certification **LAND-1 and LAND-2** to require 1:1 mitigation for all impacted prime and farmlands of statewide importance.

KERN COUNTY PLANNING AND COMMUNITY DEVELOPMENT DEPARTMENT
Lorelei Oviatt, Director of the Kern County Planning and Community Development Department submitted two letters dated June 11, 2012 and July 12, 2012 outlining the county's questions and concerns regarding the project's land use incompatibilities. In Kern County's March 6, 2013 letter, county staff determined that the applicant's revised project description, if conditioned to restrict the chemical manufacturing and storage of fertilizers for agricultural use only, would comply with the County General Plan and Zoning Ordinance (Kern 2013a). Kern County also stated that the revised project would be a conditionally permitted use in the A District. Kern County recommends that mitigation for conversion of agricultural lands be at a 1:1 ratio. Staff is recommending Conditions of Certification **LAND-1** and **LAND-2** requiring the project owner to mitigate the loss of affected farmland at a 1:1 ratio. Staff is also recommending Condition of Certification **LAND-6** requiring the project owner to restrict the chemical manufacturing of fertilizer for agricultural use only.

Kern County staff and residents in the area have expressed concerns regarding the use of eminent domain by the Energy Commission to obtain right-of-way for infrastructure including the rail spur for the project. The Kern County Board of Supervisors made a motion at their February 26, 2013 hearing to oppose the use of eminent domain associated with the HECA project (Kern 2013a). The Energy Commission does not have the power of eminent domain. In the event the applicant is unable to obtain from the adjacent landowners the required right-of-way for the rail spur as proposed, the applicant would have to use the proposed truck delivery route instead or propose an alternative rail spur route for Commission consideration.

KERN COUNTY FARM BUREAU
The Executive Director of the Kern County Farm Bureau, Inc. cited issues with the HECA project regarding agricultural impacts from the proposed rail spur, loss of farmland, disruption of farming activities and impacts to air quality. Staff has addressed the project's impacts to agricultural lands in this section and is recommending Conditions of Certification **LAND-1** and **LAND-2** to mitigate for the conversion of agricultural lands associated with the project site, linears and rail spur. Please refer to the **Traffic and Transportation** section for a detailed discussion of the proposed rail spur design and the **Air Quality** section for a discussion of air quality issues.

SIERRA CLUB
The Sierra Club submitted a letter dated July 27, 2012 identifying land use issues related to the HECA project (Sierra Club 2012b). The Sierra Club provided comments requesting the HECA project be required to mitigate at a 2:1 ratio for the loss of prime agricultural land. As discussed above, Energy Commission staff is recommending Conditions of Certification **LAND-1** and **LAND-2** which require the applicant to mitigate at a 1:1 ratio for impacts to prime agricultural land associated with the project. The requirement to mitigate impacted farmlands at a 1:1 ratio is consistent with Kern County's recommendation for agricultural impact mitigation and past Energy Commission projects for impacts to agricultural lands.

ENVIRONMENTAL PROTECTON AGENCY (EPA)
The EPA Environmental Review Office provided scoping comments regarding agricultural land use issues related to the HECA project. The EPA letter identified the

potential loss of prime agricultural lands associated with the project. As discussed above, Energy Commission staff is recommending Conditions of Certification **LAND-1** and **LAND-2,** which require the applicant to mitigate at a 1:1 ratio for impacts to prime agricultural land associated with the project.

CONCLUSIONS

Staff concludes the HECA project:

- Would convert Farmland (as classified by the Farmland Mapping and Monitoring Program). With implementation of Conditions of Certification **LAND-1** and **LAND-2**, the conversion of prime farmland and farmland of statewide importance would be mitigated at a 1:1 ratio.
- With implementation of Condition of Certification **LAND-6**, would not conflict with existing agricultural zoning.
- With implementation of Conditions of Certification **LAND-3** and **LAND-4** requiring the project owner to cancel affected Williamson Act contracts, would not conflict with the Williamson Act or contracted lands.
- Would not conflict with existing zoning for, or cause rezoning of, forest land, timberland, or timberland zoned Timberland Production.
- Would not result in the loss of forest land or conversion of forest land to non-forest use.
- Would not directly or indirectly disrupt or divide an existing community.
- With implementation of Condition of Certification **LAND-5**, would not conflict with the Kern County Land Division Ordinance.
- Would not conflict with any applicable habitat conservation plan or natural community conservation plan.
- With mitigation, would not result in a significant contribution to a cumulative impact resulting from conversion of farmland when viewed in connection with other past projects, current projects or other probable future projects.

Staff cannot conclude the HECA project:

- Would not conflict with applicable land use plan, policy, or regulation of an agency with jurisdiction, or that would normally have jurisdiction, over the project, adopted for the purpose of avoiding or mitigating environmental effects. For staff to determine compliance with LORS, staff is requesting the applicant submit a site plan demonstrating compliance with Sections 19.12.070 and 19.12.100 of the Zoning Ordinance. Staff cannot reach a conclusion that the required conditional use permit findings of approval can be made until the outstanding information identified in other technical areas is provided. Staff will address the project's compliance with setback and parking requirements and findings of approval prior to publication of the FSA/FEIS.

Staff concludes that the Occidental Elk Hills, Inc (OEHI) CO_2 Enhanced Oil Recovery (EOR) component would be consistent with the Kern County General Plan and Zoning

Ordinance and will not cause a significant environmental impact under CEQA with respect to land use in accordance with the CEQA Guidelines Appendix G and no mitigation measures are recommended.

PROPOSED CONDITIONS OF CERTIFICATION

LAND-1 The project owner shall mitigate at a 1:1 ratio for the conversion of 457.44 acres of prime agricultural land and 0.23 acre of farmland of statewide importance associated with HECA project site and associated off-site improvements (except for the rail road spur). The mitigation shall comply with one of the following strategies:

1. Payment of a mitigation in-lieu fee to Kern County or to the California Department of Conservation, along with a prepared Farmlands Mitigation Agreement. The payment shall be determined by contacting the Kern County Assessor's Office or a real estate appraiser selected by the project owner and approved by the CPM, to determine the current assessed value of the impacted prime agricultural farmland and farmland of statewide importance.
2. Securing the acquisition of an agricultural easement or otherwise creating or causing the creation of an agricultural easement for other farmland in the vicinity. Easements for prime farmland and farmland of statewide importance would be acquired based on the California Department of Conservation's FMMP maps, but in no case shall be less than a 1:1 ratio. The project owner shall designate preserved lands of substantially similar agricultural quality as the impacted lands and within Kern County. The project owner shall engage an established Land Trust to assist with the process of determining the location and suitability of lands to be placed in trust or under easement.

Verification: Sixty days prior to the start of construction, the project owner shall provide documentation to the CPM demonstrating compliance with one of these options. For option (1), documentation shall consist of proof of mitigation fee payment and a discussion of any land and/or easements purchased to date by the land trust with the mitigation fee money provided, and the provisions to guarantee that the land managed by the trust will be preserved for farming in perpetuity.

LAND-2 If the rail spur is constructed**,** the project owner shall mitigate at a 1:1 ratio for the conversion of 34.77 acres of prime agricultural land and 2.84 acres of farmland of statewide importance associated with the railroad spur. The mitigation shall comply with one of the following strategies:

1. Payment of a mitigation in-lieu fee to Kern County or to the California Department of Conservation, along with a prepared Farmlands Mitigation Agreement. The payment shall be determined by contacting the Kern County Assessor's Office or a real estate appraiser selected by the project owner and approved by the CPM, to determine the current assessed value of the impacted prime agricultural farmland and farmland of statewide importance.

2. Securing the acquisition of an agricultural easement or otherwise creating or causing the creation of an agricultural easement for other farmland in the vicinity. Easements for prime farmland would be acquired based on the California Department of Conservation's FMMP maps, but in no case shall be less than a 1:1 ratio. The project owner shall designate preserved lands of substantially similar agricultural quality as the impacted lands and within Kern County. The project owner shall engage an established Land Trust to assist with the process of determining the location and suitability of lands to be placed in trust or under easement.

Verification: Sixty days prior to the start of construction, the project owner shall provide documentation to the CPM demonstrating compliance with one of these options. For option (1), documentation shall consist of proof of mitigation fee payment and a discussion of any land and/or easements purchased to date by the land trust with the mitigation fee money provided, and the provisions to guarantee that the land managed by the trust will be preserved for farming in perpetuity.

LAND-3: The project owner shall provide a copy of Kern County's Final Certificate of Cancellation for Cancellation of Williamson Act contract for the project site.

Verification: At least 30 days prior to construction, the project owner shall submit to the CPM a copy of Kern County's Final Certificate of Cancellation of Contract for the Williamson Act contract.

LAND-4: If the rail spur is constructed, the project owner shall provide a copy of Kern County's Final Certificate of Cancellation of Contract for the Williamson Act contract.

Verification: At least 30 days prior to construction, the project owner shall submit to the CPM a copy of Kern County's Final Certificate of Cancellation of Contract for the Williamson Act contract.

LAND-5: The project owner shall file a Lot Line Adjustment application with the Kern County Planning and Community Development Department to merge Assessor's Parcel Numbers 159-040-02 (part), 159-040-16 (part) and 159-040-18 (part) into a single parcel. The resulting approximately 453-acre parcel shall be the location of the proposed project site.

Verification: At least 30 days prior to the start of construction, the project owner shall provide the CPM a copy of the approval letter of the Lot Line Adjustment.

LAND-6: To comply with Section 19.12.030(A)(2) of the Kern County Zoning Ordinance, the project owner shall restrict the chemical manufacturing product to fertilizers for agricultural use only.

Verification: Within sixty days of commencement of commercial operation, the project owner shall submit in the Monthly Compliance Reports documentation demonstrating compliance with this requirement. The documentation shall include an attestation that all products are to be sold for agricultural use only, a list of products produced, and bills of sale.

REFERENCES

AIR 2012a- Association of Irritated Residents (AIR), Status Report and Data Requests. tn#68076. Submitted to Dockets on 10/24/2012.

Kern County 2009b- Kern County Board of Supervisors, Agricultural Preserve Standard Uniform Rules As Adopted by Various Kern County Board of Supervisors Resolutions. Agricultural and Compatible Uses. June 2009

CDOC 1997- Department of Conservation, Division of Land Resource Protection, Land Evaluation and Site Assessment Model (LESA) Instruction Manual, 1997 http://www.conservation.ca.gov/dlrp/LESA/Documents/lesamodl.pdf

CDOC 2010a- Department of Conservation, Division of Land Resource Protection, Cancellation of Land Conservation (Williamson Act) Contract: Landowner: Clifford & Brown; Applicant Hydrogen Energy California LLC: APN 159-040-16, -18. May 27, 2010.

CDOC 2010- Department of Conservation, Division of Land Resource Protection, Farmland Mapping and Monitoring Program, Central Kern County Important Farmlands 2010.

CEQA 2012- CEQA Guidelines. California Code of Regulations, Title 14, Chapter 3 Sections 15000-15387 as amended through January 1, 2012

EPA 2012a – U.S. Environmental Protection Agency (tn 66381). US EPA Scoping Comments on Amended NOI, dated 07/26/2012. Submitted to CEC Docket Unit on 07/30/2012.

HECA 2012e – SCS Energy California/Hydrogen Energy California, LLC /J. L. Croyle (tn 65049). Amended Application for Certification, Vols. I, II, and III (08-AFC-8A), dated 05/02/12. Submitted to CEC Docket Unit on 05/02/2012.

HECA 2012k – SCS Energy California, LLC/M. Mascaro/URS/ D. Shileikis (tn 65750). Applicant's Response to CEC's Data Requests Set One; Numbers A51 - A55 and Oxy Elk Hills MRV Plan, dated 6/6/2012. Submitted to CEC Docket Unit on 06/06/2012.

HECA 2012p – SCS Energy California, LLC/M. Mascaro/URS/ D. Shileikis (tn 66876). Applicant's Reponses to CEC's Data Requests Set One, A1 through A123, dated 08/22/2012. Submitted to CEC Docket Unit on 08/22/2012.

HECA 2012q – SCS Energy California, LLC/M. Mascaro/URS/ D. Shileikis (tn 66979). Applicant's Reponses to Sierra Club's Data Requests Numbers 1 through 97, dated 08/31/2012. Submitted to CEC Docket Unit on 08/31/2012.

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HECA 2012jj – SCS Energy California, LLC/M. Mascaro/URS/ D. Shileikis (tn 68729). Applicant Responses to Sierra Club's Data Requests Numbers 98 through 131, dated 11/30/2012. Submitted to CEC Docket Unit on 11/30/2012.

HECA 2012kk - SCS Energy California, LLC/M. Mascaro/URS/ D. Shileikis (tn 68731). Applicant's Reponses to A.I.R's Data Request Numbers 12 through 42, dated, 11/30/2012. Submitted to CEC Docket Unit on 11/30/2012.

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Kern County 2013a- Kern County Planning and Community Development (tn 69831) Hydrogen Energy California- Amended Application for Certification (08-AFC-8A) Presentation of specific Kern County Comments and recommended Mitigation Measures to address potential impacts of the proposed HECA Project within Kern County dated March 6, 2013.

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Land Use

Appendix A: California Agricultural LES Worksheet

Appendix A. California Agricultural LESA Worksheet

The California Agricultural LESA Model is composed of six different factors. Two "Land Evaluation" factors are based upon measures of soil resource quality. Four "Site Assessment" factors provide measures of a given project's size, water resource availability, surrounding agricultural lands, and surrounding protected resource lands. For a given project, each of these factors is separately rated on a 100 point scale. The factors are then weighted relative to one another and combined, resulting in a single numeric score for a given project, with a maximum attainable score of 100 points. It is this project score that becomes the basis for making a determination of a project's potential significance, based upon a range of established scoring thresholds. The California Agricultural LESA Instruction Manual found at the California Department of Conservation, Division of Land Resource Protection website provides detailed instructions on how to complete the LESA worksheet.

Calculation of the Land Evaluation (LE) Score

Part 1. Land Capability Classification (LCC) Score

(1) Determine the total acreage of the project.
(2) Determine the soil types within the project area and enter them in **Column A** of the **Land Evaluation Worksheet** provided on page A-2.
(3) Calculate the total acres of each soil type and enter the amounts in **Column B**.
(4) Divide the acres of each soil type (**Column B**) by the total acreage to determine the proportion of each soil type present. Enter the proportion of each soil type in **Column C**.
(5) Determine the LCC for each soil type from the applicable Soil Survey and enter it in **Column D**
(6) From the LCC Scoring Table below, determine the point rating corresponding to the LCC for each soil type and enter it in **Column E**.

LCC Scoring Table

LCC Class	I	IIe	IIs, w	IIIe	IIIs, w	IVe	IVs, w	V	VIe, s, w	VIIe, s, w	VIII
Points	100	90	80	70	60	50	40	30	20	10	0

(7) Multiply the proportion of each soil type (**Column C**) by the point score (**Column E**) and enter the resulting scores in **Column F**.
(8) Sum the LCC scores in **Column F**.
(9) Enter the LCC score in box <1> of the Final LESA Score Sheet on page A-10.

Part 2. Storie Index Score

(1) Determine the Storie Index rating for each soil type and enter it in **Column G**.
(2) Multiply the proportion of each soil type (**Column C**) by the Storie Index rating (**Column G**) and enter the scores in **Column H**.
(3) Sum the Storie Index scores in **Column H** to gain the Storie Index Score.
(4) Enter the Storie Index Score in box <2> of the Final LESA Score Sheet on page A-10.

Land Evaluation Worksheet
Land Capability Classification (LCC) and Storie Index Scores

A	B	C	D	E	F	G	H
Soil Map Unit	Project Acres	Proportion of Project Area	LCC	LCC Rating	LCC Score	Storie Index	Storie Index Score
123	135.9	21.70%	2S	80	17.36	33	7.161
187	317.1	78.30%	2S	80	62.64	41	32.103
	453						
Totals	453	100.00		***LCC Total Score***	80.00	***Storie Index Total Score***	39.26
		(Must Sum To 1.0)					

Site Assessment Worksheet 1.
Project Size Score

	I	J	K
	LCC Class I - II	LCC Class III	LCC Class IV- VIII
	453		
Total Acres	453		
Project Size Scores	100		
Highest Project Size Score		100	

Part 1. Project Size Score

(1) Using **Site Assessment Worksheet 1** provided on page A-2, enter the acreage of each soil type from **Column B** in the **Column I, J or K** that corresponds to the LCC for that soil. (Note: While the Project Size Score is a component of the Site Assessment calculations, the score sheet is an extension of data collected in the Land Evaluation Worksheet, and is therefore displayed beside it.)

(2) Sum **Column** I to determine the total amount of class I and II soils on the project site.

(3) Sum **Column J** to determine the total amount of class III soils on the project site.

(4) Sum **Column K** to determine the total amount of class IV and lower soils on the project site.

(5) Compare the total score for each LCC group in the Project Size Scoring Table below and determine which group receives the highest score.

Project Size Scoring Table

Class I or II		Class III		Class IV or Lower	
Acreage	Points	Acreage	Points	Acreage	Points
>80	100	>160	100	>320	100
60-79	90	120-159	90	240-319	80
40-59	80	80-119	80	160-239	60
20-39	50	60-79	70	100-159	40
10-19	30	40-59	60	40-99	20
10<	0	20-39	30	40<	0
		10-19	10		
		10<	0		

(6) Enter the **Project Size Score** (the highest score from the three LCC categories) in box <3> of the Final LESA Score Sheet on page A-10.

Part 2. Water Resource Availability Score

(1) Determine the type(s) of irrigation present on the project site, including a determination of whether there is dry land agricultural activity as well.

(2) Divide the site into portions according to the type or types of irrigation or dry land cropping that is available in each portion. Enter this information in **Column B** of **Site Assessment Worksheet 2 - Water Resources Availability** provided on page A-5.

(3) Determine the proportion of the total site represented for each portion identified, and enter this information in **Column C**.

(4) Using the Water Resources Availability Scoring Table provided on page A-6, identify the option that is most applicable for each portion, based upon the feasibility of irrigation in drought and non-drought years, and whether physical or economic restrictions are likely to exist. Enter the applicable Water Resource Availability Score into **Column D**.

(5) Multiply the Water Resource Availability Score for each portion by the proportion of the project area it represents to determine the weighted score for each portion in **Column E**.

(6) Sum the scores for all portions to determine the project's total Water Resources Availability Score.

(7) Enter the Water Resource Availability Score in box <4> of the Final LESA Score Sheet on page A-10.

Site Assessment Worksheet 2.
Water Resource Availability

A Project Portion	B Water Source	C Proportion of Project Area	D Water Availability Score	E Weighted Availability Score (C x D)
1	Groundwater	1	95	95
2				
3				
4				
5				
6				
		1.00 (Must Sum to 1.0)	***Total Water Resource Score***	95.00

Water Resource Availability Scoring Table

Option	Non-Drought Years			Drought Years			WATER RESOURCE SCORE
	RESTRICTIONS			RESTRICTIONS			
	Irrigated Production Feasible?	Physical Restrictions ?	Economic Restrictions ?	Irrigated Production Feasible?	Physical Restrictions ?	Economic Restrictions?	
1	YES	NO	NO	YES	NO	NO	100
2	YES	NO	NO	YES	NO	YES	95
3	YES	NO	YES	YES	NO	YES	90
4	YES	NO	NO	YES	YES	NO	85
5	YES	NO	NO	YES	YES	YES	80
6	YES	YES	NO	YES	YES	NO	75
7	YES	YES	YES	YES	YES	YES	65
8	YES	NO	NO	NO	--	--	50
9	YES	NO	YES	NO	--	--	45
10	YES	YES	NO	NO	--	--	35
11	YES	YES	YES	NO	--	--	30
12	Irrigated production not feasible, but rainfall adequate for dry land production in both drought and non-drought years.						25
13	Irrigated production not feasible, but rainfall adequate for dry land production in non-drought years but not in drought years).						20
14	Neither irrigated nor dry land production feasible.						0

Part 3. Surrounding Agricultural Land Use Score

(1) Calculate the project's Zone of Influence (ZOI) as follows:

(a) a rectangle is drawn around the project such that the rectangle is the smallest that can completely encompass the project area.

(b) a second rectangle is then drawn which extends one quarter mile (1,320 feet) on all sides beyond the first rectangle.

(c) The ZOI includes all parcels that are contained within or are intersected by the second rectangle, less the area of the project itself.

(2) Sum the area of all parcels to determine the total acreage of the ZOI.

(3) Determine which parcels are in agricultural use and sum the areas of these parcels.

(4) Divide the area in agriculture found in step (3) by the total area of the ZOI found in step (2) to determine the percent of the ZOI that is in agricultural use.

(5) Determine the Surrounding Agricultural Land Score utilizing the Surrounding Agricultural Land Scoring Table below.

Surrounding Agricultural Land Scoring Table

Percent of ZOI in Agriculture	Surrounding Agricultural Land Score
90-100	100
80-89	95
70-79	90
65-69	85
60-64	80
55-59	70
50-54	60
45-49	50
40-44	40
35-39	30
30-34	20
20-29	10
<19	0

(6) Enter the Surrounding Agricultural Land Score in box <5> of the Final LESA Score Sheet on page A-10.

Part 4. Surrounding Protected Resource Land Score

The Surrounding Protected Resource Land scoring relies upon the same Zone of Influence information gathered in Part 3, and figures are entered in Site Assessment Worksheet 3, which combines the surrounding agricultural and protected lands calculations.

(1) Use the total area of the ZOI calculated in Part 3 for the Surrounding Agricultural Land Use score.

(2) Sum the area of those parcels within the ZOI that are protected resource lands, as defined in the LESA Instruction Manual (e.g., Williamson Act contracted lands, publicly owned lands maintained as park, forest, or watershed resources).

(3) Divide the area that is determined to be protected in step (2) by the total acreage of the ZOI to determine the percentage of the surrounding area that is under resource protection.

(4) Determine the Surrounding Protected Resource Land Score utilizing the Surrounding Protected Resource Land Scoring Table below.

Surrounding Protected Resource Land Scoring Table

Percent of ZOI Protected	Protected Resource Land Score
90-100	100
80-89	95
70-79	90
65-69	85
60-64	80
55-59	70
50-54	60
45-49	50
40-44	40
35-39	30
30-34	20
20-29	10
<20	0

(5) Enter the Surrounding Protected Resource Land score in box <6> of the Final LESA Score Sheet on page A-10.

Surrounding Agricultural Land and Surrounding Protected Resource Land

A	B	C	D	E	F	G
Zone of Influence					Surrounding Agricultural Land Score (from table on page A-7)	Surrounding Protected Resource Land Score (from table on page A-8)
Total Acres	Acres in Agriculture	Acres of Protected Resource Land	Percent in Agriculture (B/A)	Percent Protected Resource Land (C/A)		
600	100	100	100	100	100	100

Final LESA Score Sheet

Calculation of the Final LESA Score

(1) Multiply each factor score by the factor weight to determine the weighted score and enter in Weighted Factor Scores column.
(2) Sum the weighted factor scores for the LE factors to determine the total LE score for the project.
(3) Sum the weighted factor scores for the SA factors to determine the total SA score for the project.
(4) Sum the total LE and SA scores to determine the Final LESA Score for the project.

		Factor Scores	Factor Weight	Weighted Factor Scores
LE Factors				
Land Capability Classification (see page A-2)	<1>	80	0.25	20
Storie Index Rating (see page A-2)	<2>	39.26	0.25	9.815
LE Subtotal			**0.50**	**29.815**
SA Factors				
Project Size (see page A-2)	<3>	100	0.15	15
Water Resource Availability (see page A-5)	<4>	95	0.15	14.25
Surrounding Agricultural Land (see page A-9)	<5>	100	0.15	15
Surrounding Protected Resource Land (see page A-9)	<6>	100	0.05	5
SA Subtotal			**0.50**	**49.25**
			Final LESA Score	**79.065**

California Agricultural LESA Scoring Thresholds

Total LESA Score		Scoring Decision
0 to 39 points		Not Considered Significant
40 to 59 points		Considered Significant only if LE and SA subscores are each greater than or equal to 20 points
60 to 79 points		Considered Significant unless either LE or SA subscore is less than 20 points
80 to 100 points		Considered Significant

The California Agricultural LESA Model is designed to make determinations of the potential significance of a project's conversion of agricultural lands during the Initial Study phase of the CEQA review process. Scoring thresholds are based upon both the total LESA score as well the component LE and SA subscores. In this manner the scoring thresholds are dependent upon the attainment of a minimum score for the LE and SA subscores so that a single threshold is not the result of heavily skewed subscores (i.e., a site with a very high LE score, but a very low SA score, or vice versa). For additional information on the significance scoring thresholds under the California Agricultural LESA Model, consult Section 4 in the LESA Instruction Manual.

Land Use

Appendix B: California Agricultural LES Worksheet for Proposed Rail Line

Appendix B. California Agricultural LESA Worksheet for Proposed Rail Line

The California Agricultural LESA Model is composed of six different factors. Two "Land Evaluation" factors are based upon measures of soil resource quality. Four "Site Assessment" factors provide measures of a given project's size, water resource availability, surrounding agricultural lands, and surrounding protected resource lands. For a given project, each of these factors is separately rated on a 100 point scale. The factors are then weighted relative to one another and combined, resulting in a single numeric score for a given project, with a maximum attainable score of 100 points. It is this project score that becomes the basis for making a determination of a project's potential significance, based upon a range of established scoring thresholds. The California Agricultural LESA Instruction Manual found at the California Department of Conservation, Division of Land Resource Protection website provides detailed instructions on how to complete the LESA worksheet.

Calculation of the Land Evaluation (LE) Score

Part 1. Land Capability Classification (LCC) Score

(1) Determine the total acreage of the project.
(2) Determine the soil types within the project area and enter them in **Column A** of the **Land Evaluation Worksheet** provided on page A-2.
(3) Calculate the total acres of each soil type and enter the amounts in **Column B.**
(4) Divide the acres of each soil type (**Column B**) by the total acreage to determine the proportion of each soil type present. Enter the proportion of each soil type in **Column C.**
(5) Determine the LCC for each soil type from the applicable Soil Survey and enter it in **Column D**
(6) From the LCC Scoring Table below, determine the point rating corresponding to the LCC for each soil type and enter it in **Column E.**

LCC Scoring Table

LCC Class	I	IIe	IIs, w	IIIe	IIIs, w	IVe	IVs, w	V	VIe, s, w	VIIe, s, w	VIII
Points	100	90	80	70	60	50	40	30	20	10	0

(7) Multiply the proportion of each soil type (**Column C**) by the point score (**Column E**) and enter the resulting scores in **Column F.**
(8) Sum the LCC scores in **Column F.**
(9) Enter the LCC score in box <1> of the Final LESA Score Sheet on page A-10.

Part 2. Storie Index Score

(1) Determine the Storie Index rating for each soil type and enter it in **Column G.**
(2) Multiply the proportion of each soil type (**Column C**) by the Storie Index rating (**Column G**) and enter the scores in **Column H.**
(3) Sum the Storie Index scores in **Column H** to gain the Storie Index Score.
(4) Enter the Storie Index Score in box <2> of the Final LESA Score Sheet on page A-10.

Land Evaluation Worksheet
Land Capability Classification (LCC) and Storie Index Scores

A	B	C	D	E	F	G	H
Soil Map Unit	Project Acres	Proportion of Project Area	LCC	LCC Rating	LCC Score	Storie Index	Storie Index Score
123	29.34	76.00%	2s	80	60.8	33	25.08
125	0.04	0.10%	3s	60	0.06	67	0.07
156	3.47	9%	3s	60	5.4	32	2.88
174	0.39	1%	1	100	1	82	0.82
187	4.63	12.00%	2s	80	9.6	41	4.92
196	0.054	1.40%	1	100	1.4	72	1.01
Totals	38.6	100.00		***LCC Total Score***	78.26	***Storie Index Total Score***	34.78
		(Must Sum To 1.0)					

Site Assessment Worksheet 1.
Project Size Score

	I	J	K
	LCC Class I - II	LCC Class III	LCC Class IV- VIII
	29.34		
		0.04	
		3.47	
	0.39		
	4.63		
	0.054		
Total Acres	34.414	3.51	
Project Size Scores	50	0	
Highest Project Size Score		50	

Part 1. Project Size Score

(1) Using **Site Assessment Worksheet 1** provided on page A-2, enter the acreage of each soil type from **Column B** in the **Column I, J or K** that corresponds to the LCC for that soil. (Note: While the Project Size Score is a component of the Site Assessment calculations, the score sheet is an extension of data collected in the Land Evaluation Worksheet, and is therefore displayed beside it.)

(2) Sum **Column I** to determine the total amount of class I and II soils on the project site.

(3) Sum **Column J** to determine the total amount of class III soils on the project site.

(4) Sum **Column K** to determine the total amount of class IV and lower soils on the project site.

(5) Compare the total score for each LCC group in the Project Size Scoring Table below and determine which group receives the highest score.

Project Size Scoring Table

Class I or II			Class III			Class IV or Lower	
Acreage	Points		Acreage	Points		Acreage	Points
>80	100		>160	100		>320	100
60-79	90		120-159	90		240-319	80
40-59	80		80-119	80		160-239	60
20-39	50		60-79	70		100-159	40
10-19	30		40-59	60		40-99	20
10<	0		20-39	30		40<	0
			10-19	10			
			10<	0			

(6) Enter the **Project Size Score** (the highest score from the three LCC categories) in box <3> of the Final LESA Score Sheet on page A-10.

Part 2. Water Resource Availability Score

(1) Determine the type(s) of irrigation present on the project site, including a determination of whether there is dry land agricultural activity as well.

(2) Divide the site into portions according to the type or types of irrigation or dry land cropping that is available in each portion. Enter this information in **Column B of Site Assessment Worksheet 2 - Water Resources Availability** provided on page A-5.

(3) Determine the proportion of the total site represented for each portion identified, and enter this information in **Column C**.

(4) Using the Water Resources Availability Scoring Table provided on page A-6, identify the option that is most applicable for each portion, based upon the feasibility of irrigation in drought and non-drought years, and whether physical or economic restrictions are likely to exist. Enter the applicable Water Resource Availability Score into **Column D**.

(5) Multiply the Water Resource Availability Score for each portion by the proportion of the project area it represents to determine the weighted score for each portion in **Column E**.

(6) Sum the scores for all portions to determine the project's total Water Resources Availability Score.

(7) Enter the Water Resource Availability Score in box <4> of the Final LESA Score Sheet on page A-10.

Site Assessment Worksheet 2.
Water Resource Availability

A Project Portion	B Water Source	C Proportion of Project Area	D Water Availability Score	E Weighted Availability Score (C x D)
1	Groundwater	1	95	95
2				
3				
4				
5				
6				
		1.00 (Must Sum to 1.0)	***Total Water Resource Score***	95.00

Water Resource Availability Scoring Table

Option	Non-Drought Years			Drought Years			WATER RESOURCE SCORE
	RESTRICTIONS			RESTRICTIONS			
	Irrigated Production Feasible?	Physical Restrictions ?	Economic Restrictions ?	Irrigated Production Feasible?	Physical Restrictions ?	Economic Restrictions?	
1	YES	NO	NO	YES	NO	NO	100
2	YES	NO	NO	YES	NO	YES	95
3	YES	NO	YES	YES	NO	YES	90
4	YES	NO	NO	YES	YES	NO	85
5	YES	NO	NO	YES	YES	YES	80
6	YES	YES	NO	YES	YES	NO	75
7	YES	YES	YES	YES	YES	YES	65
8	YES	NO	NO	NO	--	--	50
9	YES	NO	YES	NO	--	--	45
10	YES	YES	NO	NO	--	--	35
11	YES	YES	YES	NO	--	--	30
12	Irrigated production not feasible, but rainfall adequate for dry land production in both drought and non-drought years.						25
13	Irrigated production not feasible, but rainfall adequate for dry land production in non-drought years but not in drought years).						20
14	Neither irrigated nor dry land production feasible.						0

Part 3. Surrounding Agricultural Land Use Score

(1) Calculate the project's Zone of Influence (ZOI) as follows:

(a) a rectangle is drawn around the project such that the rectangle is the smallest that can completely encompass the project area.

(b) a second rectangle is then drawn which extends one quarter mile (1,320 feet) on all sides beyond the first rectangle.

(c) The ZOI includes all parcels that are contained within or are intersected by the second rectangle, less the area of the project itself.

(2) Sum the area of all parcels to determine the total acreage of the ZOI.

(3) Determine which parcels are in agricultural use and sum the areas of these parcels.

(4) Divide the area in agriculture found in step (3) by the total area of the ZOI found in step (2) to determine the percent of the ZOI that is in agricultural use.

(5) Determine the Surrounding Agricultural Land Score utilizing the Surrounding Agricultural Land Scoring Table below.

Surrounding Agricultural Land Scoring Table

Percent of ZOI in Agriculture	Surrounding Agricultural Land Score
90-100	100
80-89	95
70-79	90
65-69	85
60-64	80
55-59	70
50-54	60
45-49	50
40-44	40
35-39	30
30-34	20
20-29	10
<19	0

(6) Enter the Surrounding Agricultural Land Score in box <5> of the Final LESA Score Sheet on page A-10.

Part 4. Surrounding Protected Resource Land Score

The Surrounding Protected Resource Land scoring relies upon the same Zone of Influence information gathered in Part 3, and figures are entered in Site Assessment Worksheet 3, which combines the surrounding agricultural and protected lands calculations.

(1) Use the total area of the ZOI calculated in Part 3 for the Surrounding Agricultural Land Use score.

(2) Sum the area of those parcels within the ZOI that are protected resource lands, as defined in the LESA Instruction Manual (e.g., Williamson Act contracted lands, publicly owned lands maintained as park, forest, or watershed resources).

(3) Divide the area that is determined to be protected in step (2) by the total acreage of the ZOI to determine the percentage of the surrounding area that is under resource protection.

(4) Determine the Surrounding Protected Resource Land Score utilizing the Surrounding Protected Resource Land Scoring Table below.

Surrounding Protected Resource Land Scoring Table

Percent of ZOI Protected	Protected Resource Land Score
90-100	100
80-89	95
70-79	90
65-69	85
60-64	80
55-59	70
50-54	60
45-49	50
40-44	40
35-39	30
30-34	20
20-29	10
<20	0

(5) Enter the Surrounding Protected Resource Land score in box <6> of the Final LESA Score Sheet on page A-10.

Surrounding Agricultural Land and Surrounding Protected Resource Land

A	B	C	D	E	F	G
Zone of Influence					Surrounding Agricultural Land Score (from table on page A-7)	Surrounding Protected Resource Land Score (from table on page A-8)
Total Acres	Acres in Agriculture	Acres of Protected Resource Land	Percent in Agriculture (B/A)	Percent Protected Resource Land (C/A)		

Final LESA Score Sheet

<u>Calculation of the Final LESA Score</u>

(1) Multiply each factor score by the factor weight to determine the weighted score and enter in Weighted Factor Scores column.

(2) Sum the weighted factor scores for the LE factors to determine the total LE score for the project.

(3) Sum the weighted factor scores for the SA factors to determine the total SA score for the project.

(4) Sum the total LE and SA scores to determine the Final LESA Score for the project.

		Factor Scores	Factor Weight	Weighted Factor Scores
LE Factors				
Land Capability Classification (see page A-2)	<1>	78.26	0.25	19.565
Storie Index Rating (see page A-2)	<2>	34.78	0.25	8.695
LE Subtotal			**0.50**	**28.26**
SA Factors				
Project Size (see page A-2)	<3>	50	0.15	7.5
Water Resource Availability (see page A-5)	<4>	95	0.15	14.25
Surrounding Agricultural Land (see page A-9)	<5>	100	0.15	15
Surrounding Protected Resource Land (see page A-9)	<6>	80	0.05	4
SA Subtotal			**0.50**	**40.75**
			Final LESA Score	**69.01**

California Agricultural LESA Scoring Thresholds

Total LESA Score		Scoring Decision
0 to 39 points		Not Considered Significant
40 to 59 points		Considered Significant only if LE and SA subscores are each greater than or equal to 20 points
60 to 79 points		Considered Significant unless either LE or SA subscore is less than 20 points
80 to 100 points		Considered Significant

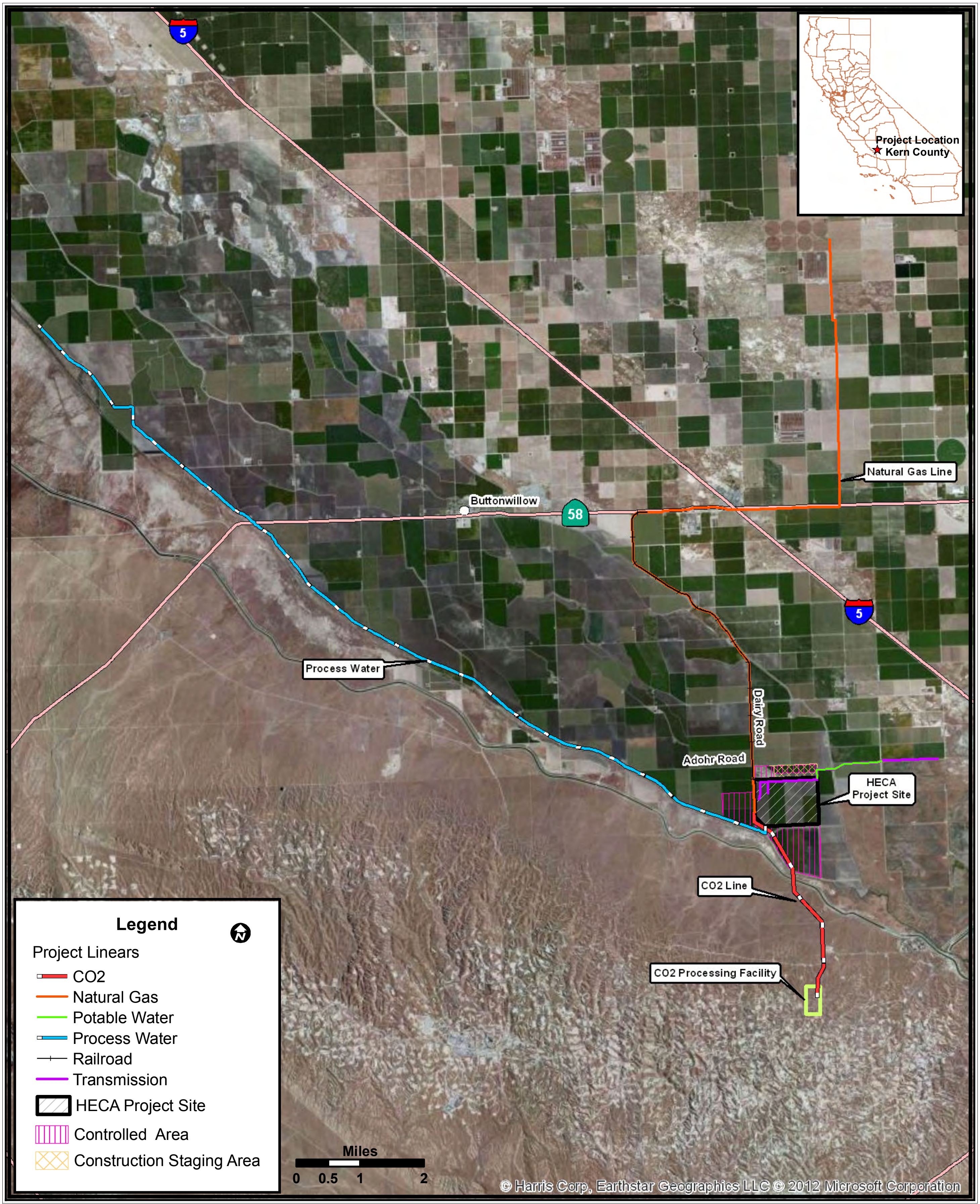
The California Agricultural LESA Model is designed to make determinations of the potential significance of a project's conversion of agricultural lands during the Initial Study phase of the CEQA review process. Scoring thresholds are based upon both the total LESA score as well the component LE and SA subscores. In this manner the scoring thresholds are dependent upon the attainment of a minimum score for the LE and SA subscores so that a single threshold is not the result of heavily skewed subscores (i.e., a site with a very high LE score, but a very low SA score, or vice versa). For additional information on the significance scoring thresholds under the California Agricultural LESA Model, consult Section 4 in the LESA Instruction Manual.

LAND USE - FIGURE 1
Hydrogen Energy California - Regional Project Location Map

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: AFC Figure 2-1

LAND USE - FIGURE 2

Hydrogen Energy California - Site Plan, including Controlled Area and Linears

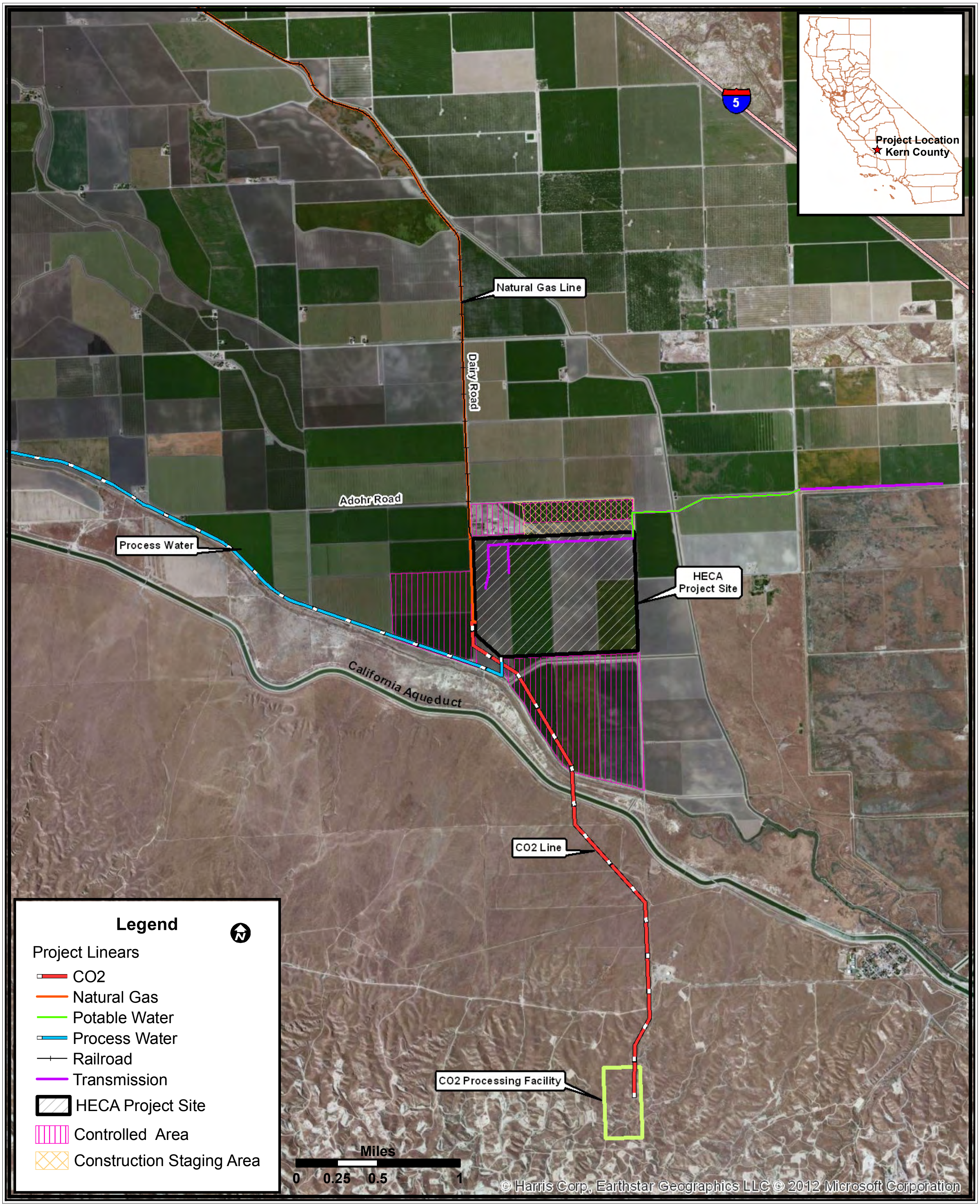


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: ESRI - URS

LAND USE - FIGURE 2a

Hydrogen Energy California - Site Plan, including Controlled Area and Linears

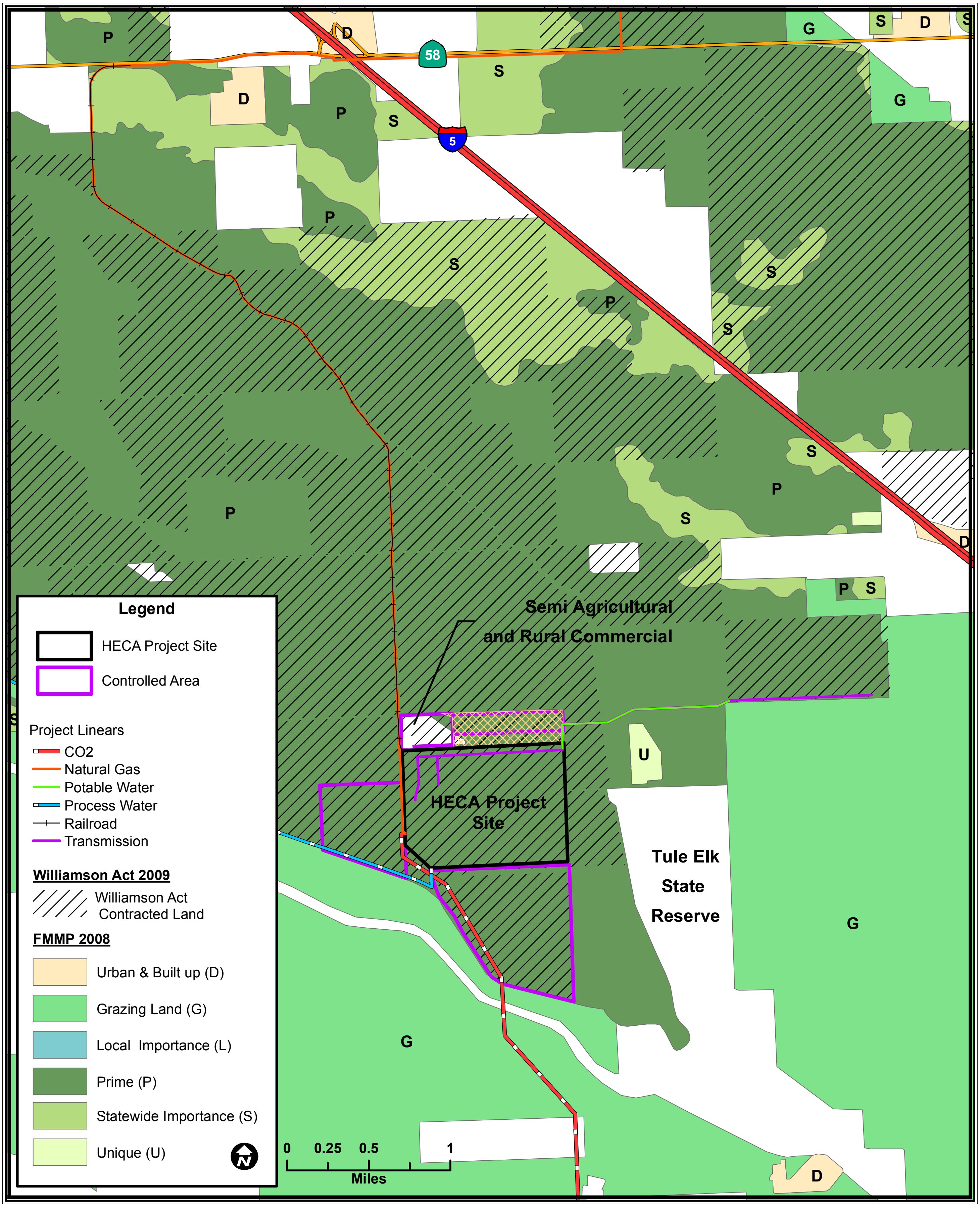


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: ESRI - URS

LAND USE - FIGURE 3

Hydrogen Energy California - Important Farmland

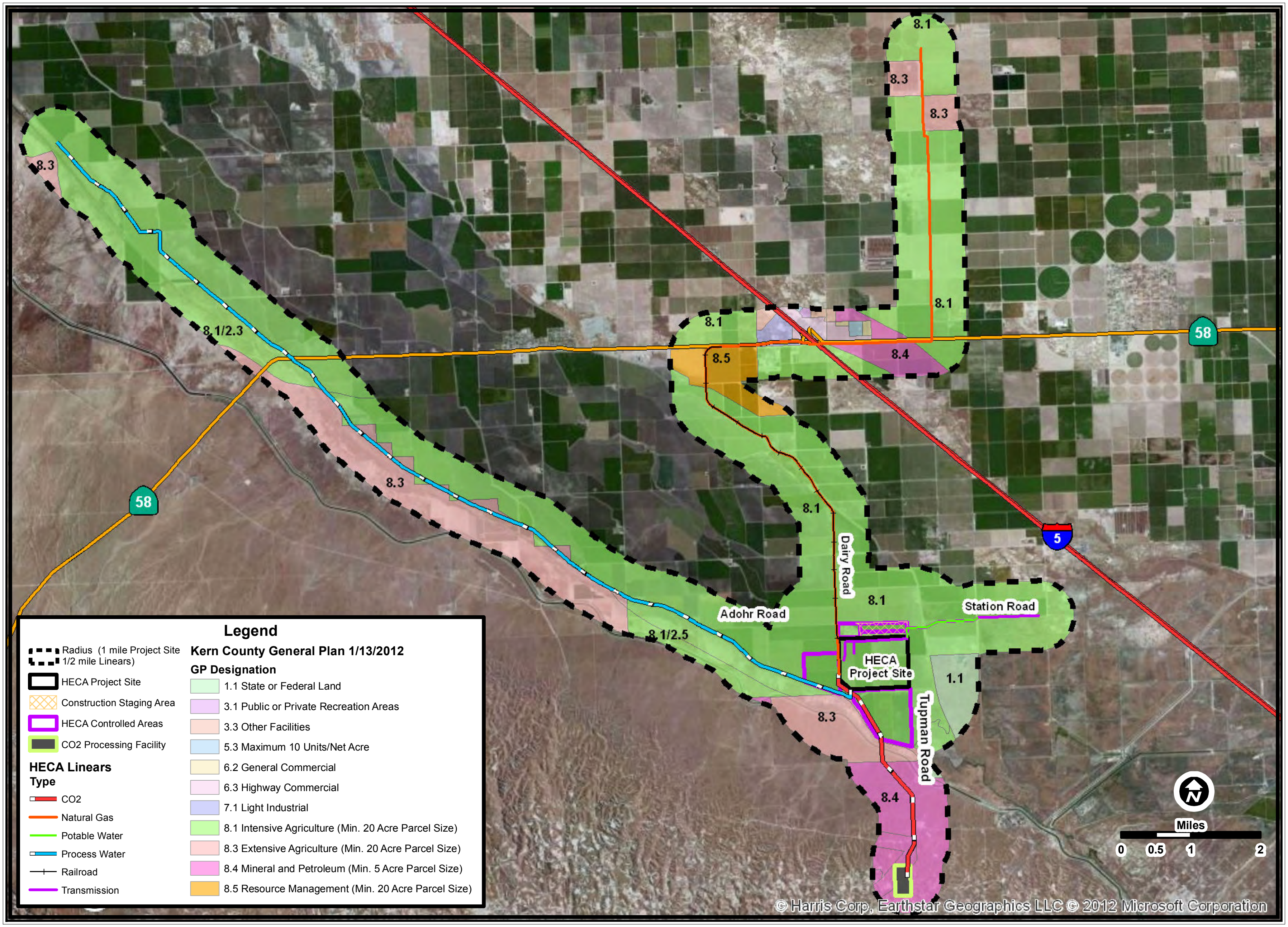


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: URS - CA Dept. of Conservation Farmland Mapping and Monitoring Program

LAND USE - FIGURE 4

Hydrogen Energy California - General Plan Land Use Designations Surrounding Project Site

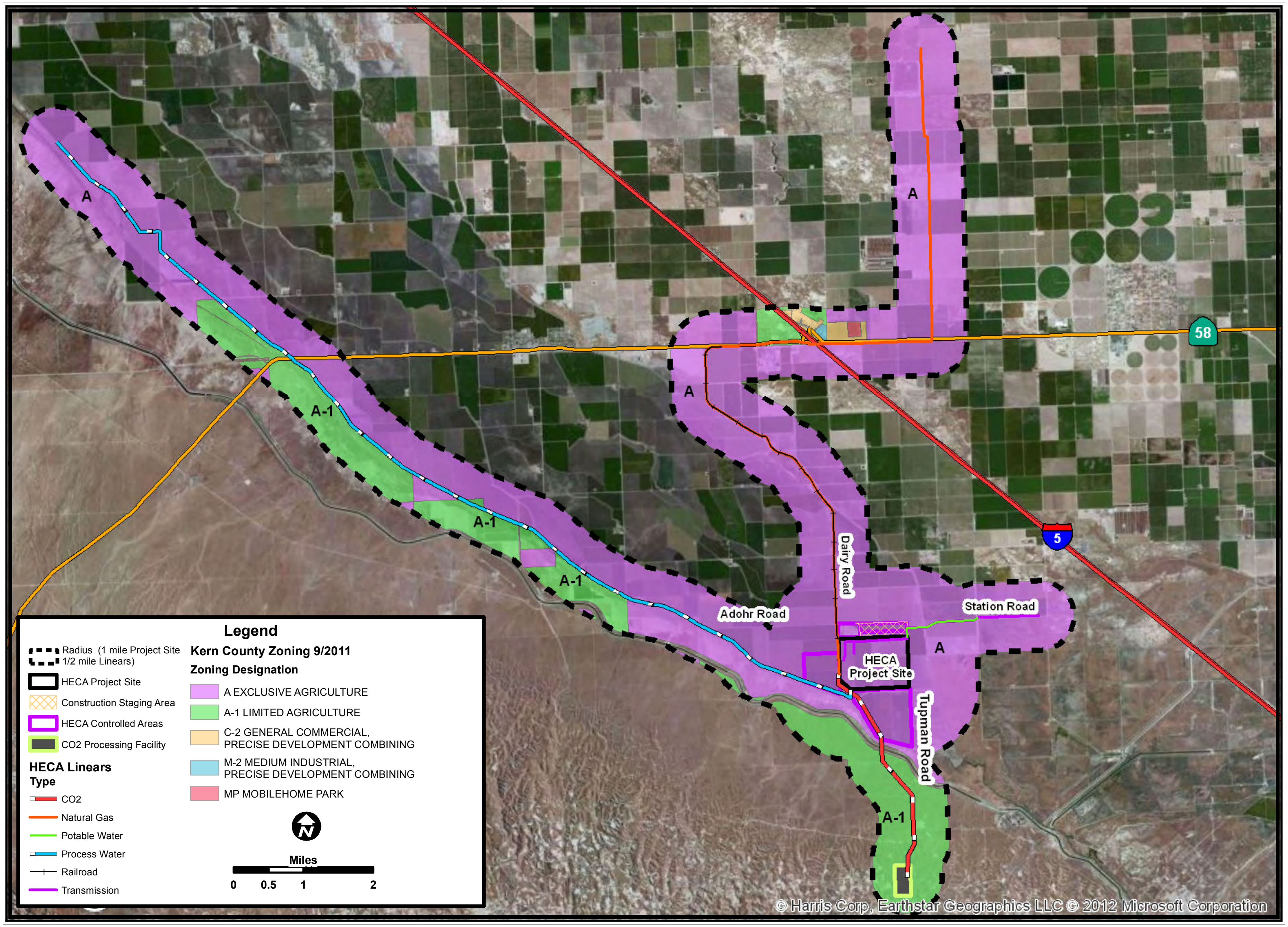


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: BING - Multinet - URS and Kern County General Plan Updated 1/13/2012

LAND USE - FIGURE 5

Hydrogen Energy California - Zoning around Project Footprint and Controlled Area



LAND USE

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: BING - Multinet - URS and Kern County General Plan Updated 1/13/2012

NOISE AND VIBRATION

Edward Brady and Shahab Khoshamshrab

SUMMARY OF CONCLUSIONS

California Energy Commission staff concludes that the Hydrogen Energy California Project (HECA) can be built and operated in compliance with all applicable noise and vibration laws, ordinances, regulations, and standards and, if built in accordance with the conditions of certification proposed below, would produce no significant adverse noise impacts on people within the affected area, either direct, indirect, or cumulative.

INTRODUCTION

The construction and operation of any large industrial facility creates noise, or unwanted sound. The character and loudness of this noise, the times of day or night that it is produced, and the proximity of the facility to sensitive receptors combine to determine whether the facility would meet applicable noise control laws and ordinances and whether it would cause significant adverse environmental impacts. In some cases, vibration may be produced as a result of project construction practices, such as blasting or pile driving. The groundborne energy of vibration has the potential to cause structural damage and annoyance.

The purpose of this analysis is to identify and examine the likely noise and vibration impacts from the construction and operation of HECA and to recommend procedures to ensure that the resulting noise and vibration impacts would be adequately mitigated to comply with applicable laws, ordinances, regulations, and standards (LORS) and to avoid creation of significant adverse noise or vibration impacts. This analysis evaluates the noise and vibration impacts of both, the HECA project and the Enhanced Oil Recovery facility (EOR). Therefore, for the purposes of this analysis, the project consists of the feedstock handling block, fuel gasification block, power generation block, ammonia production complex, air separation unit, CO_2 transmission system, and EOR. For an explanation of technical terms and acronyms employed in this section, please refer to **Noise and Vibration Appendix A** immediately following.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Noise and Vibration Table 1
Summary of Laws, Ordinances, Regulations, and Standards (LORS)

Applicable LORS	Description
Federal (OSHA): 29 U.S.C. § 651 et seq.	Protects workers from the effects of occupational noise exposure.
State (Cal/OSHA): Cal. Code Regs., tit. 8, §§ 5095–5099	Protects workers from the effects of occupational noise exposure.
Local Kern County General Plan Noise Element Policies (5)(a) and (5)(b)	Policy (5) prohibits new noise-sensitive land uses in noise-impacted areas unless effective mitigation measures are incorporated to (a) reduce noise levels in outdoor activity

Applicable LORS	Description
	areas to 65 dBA L_{dn}[1] or less, and (b) reduce interior noise levels to 45 dBA L_{dn} or less.
Kern County Code of Ordinance, Chapter 8.36 (“Noise Control”)	Subsection H limits hours of noisy construction work.

FEDERAL

Under the Occupational Safety and Health Act of 1970 (29 USC § 651 et seq.), the Department of Labor, Occupational Safety and Health Administration (OSHA) has adopted regulations designed to protect workers against the effects of occupational noise exposure (29 CFR § 1910.95). These regulations list permissible noise exposure levels as a function of the amount of time during which the worker is exposed (see **Noise and Vibration Appendix A, Table A4** immediately following this section). The regulations further specify a hearing conservation program that involves monitoring the noise to which workers are exposed, assuring that workers are made aware of overexposure to noise, and periodically testing the workers’ hearing to detect any degradation.

There are no federal laws governing off-site (community) noise.

The only guidance available for evaluation of vibration from large industrial plants is guidelines published by the Federal Transit Administration (FTA) for assessing the impacts of groundborne vibration associated with construction of rail projects. These guidelines have been applied by other jurisdictions to assess groundborne vibration of other types of projects. The FTA-recommended vibration standards are expressed in terms of the “vibration level,” which is calculated from the peak particle velocity measured from groundborne vibration. The FTA measure of the threshold of perception is 65 VdB,[2] which correlates to a peak particle velocity of about 0.002 inches per second (in/sec). The FTA measure of the threshold of architectural damage for conventional sensitive structures is 100 VdB, which correlates to a peak particle velocity of about 0.2 in/sec.

The FTA Transit Noise and Vibration Impact Assessment Manual (FTA-VA-90-1003-06) outlines key environmental impact assessment processes and procedures for mass transit projects. The methodology outlined in this document is widely used to assess potential noise impacts from railway operations and was adopted for HECA to assess potential impacts associated with the rail spur. The noise calculations and impact criteria used by the FTA are based on the change in outdoor noise exposure using a sliding scale with three receiver categories and three degrees of impact. Category 2 applies to the project’s noise-sensitive receivers[3] where people normally sleep, including homes; Outdoor L_{dn} applies to this category. Category 1 applies to Tule Elk State Natural Reserve (Tule Elk Reserve) where there is only daytime use of the facility;

[1] For definitions of the various noise measurement metrics and terminologies used in this analysis, please see **Noise and Vibration Appendix A, Table A1**.

[2] VdB is the common measure of vibration energy.

[3] A sensitive noise receptor, also referred to as a noise-sensitive receptor, is a receptor at which there is a reasonable degree of sensitivity to noise (such as residences, schools, hospitals, elder care facilities, libraries, cemeteries, and places of worship).

Outdoor hourly L_{eq} applies to this category. See the graph in Condition of Certification **NOISE-9** for a visual presentation of these criteria.

This graph presents the criteria for FTA's three degrees of impact: No Impact, Moderate Impact, and Severe Impact. As shown in this graph, the criterion for each degree of impact is on a sliding scale dependent on the existing noise exposure and the increase in noise exposure that could result from the project. NEPA considers a "severe impact" to be "significant". Staff agrees with NEPA's consideration and regards a "severe impact" to be "significant", as well.

STATE

California Government Code Section 65302(f) encourages each local governmental entity to perform noise studies and implement a noise element as part of its general plan. In addition, the California Office of Planning and Research has published guidelines for preparing noise elements, which include recommendations for evaluating the compatibility of various land uses as a function of community noise exposure.

The State of California, Office of Noise Control, prepared the Model Community Noise Control Ordinance, which provides guidance for acceptable noise levels in the absence of local noise standards. This model also defines a simple tone, or "pure tone," as one-third octave band sound pressure levels that can be used to determine whether a noise source contains annoying tonal components. The Model Community Noise Control Ordinance further recommends that, when a pure tone is present, the applicable noise standard should be lowered (made more stringent) by five A-weighted decibels (dBA).

The California Occupational Safety and Health Administration (Cal-OSHA) has promulgated occupational noise exposure regulations (Cal. Code Regs., tit. 8, §§ 5095-5099) that set employee noise exposure limits. These standards are equivalent to federal OSHA standards (see **Noise and Vibration Appendix A, Table A4**).

LOCAL

Kern County General Plan Noise Element

Two policies stated in this noise element (Kern County 2007) impact the construction and operation of a project such as HECA. Policy (5)(a) prohibits new noise-sensitive land uses in noise-impacted areas unless effective mitigation measures are incorporated into the project design to reduce noise levels in outdoor activity areas to 65 dBA L_{dn} or less. Policy (5)(b) prohibits new noise-sensitive land uses in noise impacted areas unless effective mitigation measures are incorporated into the project design to reduce interior noise levels within living spaces or other noise sensitive interior spaces to 45 dBA L_{dn} or less.

Kern County Code of Ordinance

The Noise Control Ordinance (Kern County 2009) in Chapter 8.36 of the Kern County Code states that noise from construction must be limited to the following hours when construction takes place within 1,000 feet of a sensitive receptor:

- Weekdays 6:00 a.m. to 9:00 p.m.
- Weekends 8:00 a.m. to 9:00 p.m.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

California Environmental Quality Act

The California Environmental Quality Act (CEQA) requires that significant environmental impacts be identified and that such impacts be eliminated or mitigated to the extent feasible. Section XI of Appendix G of CEQA Guidelines (Cal. Code Regs., tit. 14, App. G) sets forth some characteristics that may signify a potentially significant impact. Specifically, a significant effect from noise may exist if a project would result in:

1. exposure of persons to, or generation of, noise levels in excess of standards established in the local General Plan or noise ordinance or applicable standards of other agencies;
2. exposure of persons to or generation of excessive groundborne vibration or groundborne noise levels;
3. substantial permanent increase in ambient noise levels in the project vicinity above levels existing without the project; or
4. substantial temporary or periodic increase in ambient noise levels in the project vicinity above levels existing without the project.

The Energy Commission staff, in applying item 3 above to the analysis of this and other projects, has concluded that a potential for a significant noise impact exists where the noise of the project plus the background exceeds the background by 5 dBA or more at the nearest sensitive receptor.

Staff considers it reasonable to assume that an increase in background noise levels up to 5 dBA in a residential setting is less than significant; an increase of more than 10 dBA is considered significant. An increase between 5 and 10 dBA should be considered adverse, but may be either significant or less than significant, depending on the particular circumstances of the case.

Factors to be considered in determining the significance of an adverse impact as defined above include:

1. the resulting combined noise level;[4]
2. the duration and frequency of the noise;
3. the number of people affected; and
4. the land use designation of the affected receptor sites.

[4] For example, a noise level of 40 dBA would be considered quiet in many locations. A noise limit of 40 dBA would be consistent with the recommendations of the California Model Community Noise Control Ordinance for rural environments and with industrial noise regulations adopted by European jurisdictions. If the project would create an increase in ambient noise no greater than 10 dBA at nearby sensitive receptors, and the resulting noise level would be 40 dBA or less, the project noise level would likely be less than significant.

Noise due to construction activities is usually considered to be less than significant in terms of CEQA compliance if:

- the construction activity is temporary;
- use of heavy equipment and noisy activities are limited to daytime hours; and
- all industry-standard noise abatement measures are implemented for noise-producing equipment.

Staff uses the above method and threshold to protect the most sensitive populations, including the minority population.

SETTING

HECA would be constructed on a 453 acre site located approximately 1.5 miles northwest of the town of Tupman in western Kern County. The EOR facility would be constructed within the existing Elk Hills Oil Field at a location approximately 1.5 miles southwest of Tupman. The project site and surrounding land are agricultural and residential (HECA 2012a, AFC §§ 2.1, 5.5).

The ambient noise regime in the project vicinity consists of agriculture, wildlife, and vehicular traffic. Adjacent land uses are agricultural. The western border of the Tule Elk Reserve is located approximately 1,700 feet to the east of the project site. The nearest sensitive noise receptor is a residence located approximately 1,400 feet east of the project site (HECA 2012a, AFC § 5.5.1.3).

Ambient Noise Monitoring

In order to establish a baseline for comparison of predicted project noise to existing ambient noise, the applicant has presented the results of an ambient noise survey (HECA 2012a, AFC § 5.5.1.3; Tables 5.5-2 through 5.5-13). The survey was conducted March 2 through March 3, 2009, and again from February 28 to February 29, 2012, and monitored existing noise levels at the following locations. Locations LT-1, LT-2, ST-4 and ST-5 are shown in **Noise and Vibration Figure 1**, and locations LT-7, LT-8, MR-1 and MR-2 are shown in Data Response Figure A199-1, docketed on January 16, 2013.

1. Measuring Location LT-1: Near two residences (a single-family residence and a mobile home) located approximately 375 feet northwest of the project boundary (approximately 3,000 feet northwest of the power block at the project center). The option to purchase this 5-acre parcel adjacent to the project site was acquired subsequent to the 2009 Revised AFC. According to the applicant, these residences will not be in use during project construction and operation.
2. Measuring Location LT-2: Near two single-family residences located approximately 1,400 feet east of the eastern project boundary (approximately 4,000 feet of the project center). This represents the nearest sensitive receptor, the one most likely to be impacted by project noise. Long term monitoring showed ambient noise levels typical of a rural environment, similar to those at measuring location LT-1.
3. Measuring location ST-4: this location is approximately 3,900 feet east of the project site's nearest boundary, and 6,600 feet east of the center of the project site, at the northern extent of the Tule Elk Reserve. Short-term ambient noise-level

measurements were conducted along Station Road near the Tule Elk Reserve and were completed on March 2 and 3, 2009. Four short-term measurements were conducted with two 10-minute measurements occurring back-to-back during daytime and evening hours. An additional 1-hour-and-15-minute short-term ambient noise-level measurement was conducted during nighttime hours on April 28, 2009.

4. Measuring Location ST-5: This location is approximately 3,300 feet southeast of the project boundary and 5,900 feet southeast of the center of the project site, in the vicinity of a single-family residence. Short-term ambient noise-level measurements were completed along Tupman Road near the residence.
5. Measuring Location LT-7 (MR-1): This location is approximately 3 miles north of the project site and immediately south of an existing railroad. The primary purpose for this measurement location was to obtain ambient noise-level data near a single-family residence in close proximity to this railroad. This data is used to evaluate the impacts of the railroad spur at the point of connection to the exiting San Joaquin Valley Railroad line at the residential receptor located at MR-1, near this intersection.
6. Measuring Location LT-8 (MR-2): This location is approximately 2.5 miles northwest of the project site and approximately 3,300 feet southwest of the new railroad that would be used to transport fuel to the project site. The primary purpose for this measurement location was to obtain ambient noise-level data near a single-family residence in close proximity to this railroad. This data is used to evaluate the impacts of the new railroad spur at the nearby residential receptor located at MR-2.

Noise and Vibration Table 2 summarizes the ambient noise measurements at these sensitive receptors (HECA 2012a, AFC Tables 5.5-2 through 5.5-13):

Noise and Vibration Table 2
Summary of Measured Ambient Noise Levels

Noise-Sensitive Location	Measured Noise Levels, dBA	
	L_{eq} – Average	L_{90} – Average of the Lowest Nighttime
LT-2: East Residence	55	30
ST-4: Tule Elk Reserve	51	37
ST-5: Southeast Residence	62	33
MR-1: Near Existing Railroad	58	50
MR-2: Near New Railroad	49	30

DIRECT IMPACTS AND MITIGATION

Noise impacts associated with the project can be created by short-term construction activities and by normal long-term operation of HECA.

Please note that staff uses the same method and threshold for determining significance of an adverse noise and vibration impact on sensitive populations, including the identified environmental justice population. This method and threshold are among the most conservative and restrictive used throughout the country; they typically apply to most sensitive people.

Construction Impacts and Mitigation

Construction noise is usually considered a temporary phenomenon. Construction of HECA is expected to be typical of large scale industrial projects in terms of equipment used and other types of activities, but the construction period would extend beyond what is reasonably considered “a temporary phenomenon” (approximately 3.5 years) (HECA 2012a, AFC § 5.5.2.1, p. 5.5-31).

Compliance with LORS

There are no specific LORS limiting the loudness of construction noise in Kern County, but staff compares the projected noise levels with ambient levels (please see the following discussion under **CEQA Impacts**).

Noisy construction work within 1,000 feet of a noise-sensitive receptor would be allowed only during the daytime hours of 6:00 a.m. to 9:00 p.m. weekdays and 8:00 a.m. to 9:00 p.m. weekends in compliance with the Kern County code. To ensure that these hours are, in fact, enforced, staff proposes Condition of Certification **NOISE-8**. Therefore, the noise impacts of HECA construction activities would comply with the noise LORS.

CEQA Impacts

To evaluate construction noise impacts, staff compares the projected noise levels to the ambient. Since construction noise typically varies continually with time, it is most appropriately measured by, and compared to, the L_{eq} (energy average) metric.

The applicant has predicted the noise impacts of project construction on the nearest sensitive receptors (HECA 2012a, AFC § 5.5.2.1, Table 5.5-19). Assuming peak construction activity, a maximum noise level of 62 dBA L_{eq}, which would be due to pile installation, is projected at LT-2 (nearest receptor) in AFC Table 5.5-12. This level, combined with the average daytime ambient level of 55 dBA L_{eq}, would result in 63 dBA L_{eq}; 8 dBA above the existing ambient (please see **Noise and Vibration Table 3**). Pile driving is a subset of the foundation phase and would only be expected to last 4 to 6 months within the overall foundation construction phase. Thus, because this impact would be temporary in nature, it would be less than significant.

Again, assuming peak construction activity, a maximum noise level of 59 dBA L_{eq}, which would be due to pile installation, is projected at ST-4 (Tule Elk Reserve) in AFC Table 5.5-19. This level, combined with the average daytime ambient level of 51 dBA L_{eq}, would result in 60 dBA L_{eq}; 9 dBA above the existing ambient (please see **Noise and Vibration Table 3**). Pile installation is a subset of the foundation phase and would only be expected to last 4 to 6 months within the overall foundation construction phase. Thus, because this impact would be temporary in nature, it would be less than significant.

Similarly, assuming peak construction activity, a maximum noise level of 61 dBA L_{eq}, which would be due to pile installation, is projected at ST-5 in AFC Table 5.5-19. This level, combined with the average daytime ambient level of 62 dBA L_{eq}, would result in 65 dBA L_{eq}; 3 dBA above the existing ambient (please see **Noise and Vibration Table 3**). This is a less-than-significant impact because it's below the Energy Commission's 5 dBA threshold of potential significance.

Therefore, staff considers the noise effects of project construction at LT-2, ST-4 and ST-5 to be less than significant.

Noise and Vibration Table 3
Predicted Project Construction Noise Impacts

Receptor	Highest Construction Noise Level[1] (dBA L_{eq})	Measured Existing Ambient[2] (dBA L_{eq})	Cumulative (dBA L_{eq})	Change (dBA)
LT-2: East Residence	62	55	63	+8
ST-4: Tule Elk Reserve	59	51	60	+9
ST-5: Southeast Residence	61	62	65	+3

1 Source: HECA 2012a, AFC § 5.5.2.1, Table 5.5-19 (Pile Installation).
2 Source: Noise Table 2

To ensure the project construction would create less than significant adverse impacts at the most noise-sensitive receptors, in addition to Condition of Certification **NOISE-8**, which would restrict construction activities to the daytime hours, staff proposes Conditions of Certification **NOISE-1** and **NOISE-2**, which would establish a notification process and a noise complaint process to resolve any complaints regarding construction noise.

Linear Facilities

Linear facilities include a transmission line with approximately 15 steel poles outside of the project site, approximately 13 miles of natural gas supply pipeline, approximately 15 miles of process water supply pipeline, approximately 1 mile of potable water supply pipeline, and approximately 3 miles of pipeline transmitting carbon dioxide offsite for sequestration (HECA 2012a, AFC § 2.7.1.10). A majority of the length of these linear facilities would extend past the project site boundaries. While the construction noise levels for the linear facilities would be noticeable, construction on linears proceeds rapidly, so no particular area is exposed to noise for more than a few days.

Steam Blows

Typically, the loudest noise encountered during construction, inherent in building any project incorporating a steam turbine, is created by the steam blows. After erection and assembly of the feedwater and steam systems, the piping and tubing that comprises the steam path has accumulated dirt, rust, scale and construction debris such as weld spatter, dropped welding rods and the like. If the plant were started up without thoroughly cleaning out these systems, all this debris would find its way into the steam turbine, quickly destroying the machine.

In order to prevent this, before the steam system is connected to the turbine, the steam line is temporarily routed to the atmosphere. High pressure steam is then raised in a heat recovery steam generator (HRSG) or a boiler and allowed to escape to the atmosphere through the steam piping. This flushing action, referred to as a steam blow, is quite effective at cleaning out the steam system. A series of short steam blows, lasting two or three minutes each, is performed several times daily over a period of two or three weeks. At the end of this procedure, the steam line is connected to the steam turbine, which is then ready for operation.

These steam blows can produce noise as loud as 129 dBA at a distance of 100 feet. In order to minimize disturbance from steam blows, the applicant intends to equip steam blow piping with a silencer that will reduce noise levels by 20 to 30 dBA, or to a level of 62 to 72 dBA at the nearest residence, LT-2 (HECA 2012a, AFC § 5.5.2.1, Table 5.5-26). This is still an annoying noise level; staff proposes that, in addition to the use of a steam blow silencer, all steam blows be performed only during restricted daytime hours in order to minimize annoyance to noise-sensitive receptors (see proposed Conditions of Certification **NOISE-6** and **NOISE-7** below).

Alternatively, the applicant could elect to employ a new, quieter steam blow process, variously referred to as QuietBlow™ or Silentsteam™. This method utilizes lower pressure steam over a continuous period of approximately 36 hours. Resulting noise levels reach only about 80 dBA at 100 feet; noise levels at the nearest residence, LT-2, would thus be about 48 dBA, considerably lower than the noise level from the high pressure steam blow.

Regardless of which steam blow process the applicant chooses, staff proposes a notification process (see proposed Condition of Certification **NOISE-7** below) to make neighbors aware of impending steam blows.

Vibration

The only construction operation likely to produce vibration that could be perceived off site would be pile driving, should it be employed. Vibration attenuates rapidly; it is not likely that vibration would be perceptible at any appreciable distance from the project site. Staff therefore believes there would be no significant impacts from construction vibration.

For vibration due to the rail spur, please see the discussion in ***Vibration Due to the Rail Spur***, below.

Worker Effects

The applicant has acknowledged the need to protect construction workers from noise hazards and has recognized those applicable LORS that would protect construction workers (HECA 2012a, AFC § 5.5.2.5). To ensure that construction workers are, in fact, adequately protected, staff has proposed Condition of Certification **NOISE-3**, below, which would require a noise control program to be implemented throughout the construction period.

Operation Impacts and Mitigation

The primary noise sources of HECA include the turbine generators, cooling tower, gasification process equipment, material handling, fertilizer manufacturing complex, air separation unit, and various pumps, compressors and fans (HECA 2012a, AFC § 5.5.2.3, Appendix J-2). Staff compares the projected noise with applicable LORS. In addition, staff evaluates any increase in noise levels at sensitive receptors due to the project in order to identify any significant adverse impacts.

The applicant included the following noise mitigation measures when performing computer modeling of noise impacts from project operation (HECA 2012a, AFC § 5.5.2.3):

- Reduced-noise cooling tower cells;
- Stack silencers on HRSG exhaust;
- Noise abatement for various noise sources associated with the gasifiers;
- Low-noise procurement or shrouded or blanketed pump trains, blowers and dust handlers;
- Silencers on selected gas and steam vents to atmosphere;
- Low-noise package for the combustion turbine train; and
- Low-noise package for the steam turbine train;

The effective noise control treatments that were used in the project design modeling are a combination of vendor specification limits, acoustical designs in specific systems, and/or external treatments on selected equipment items or systems. A detailed list of noise control design features for the project is provided in the AFC (HECA 2012a, AFC Table 5.5-27).

Compliance with LORS

The applicant performed noise modeling to determine the project's noise impacts on sensitive receptors (HECA 2012a, AFC § 5.5.2.3, Tables 5.5-28 and 5.5-29). The project's operating noise levels are expected to attenuate to no more than an exterior level of 43 dBA L_{dn} and an interior level of 26 dBA L_{dn} at the nearest receptor, LT-2. This figure complies with the noise level limits specified in the Kern County General Plan Noise Element, as shown in **Noise and Vibration Table 4**.

Noise and Vibration Table 4
Project Operating Noise LORS Compliance

Receptor	Kern County General Plan Noise Element Standard, L_{dn}	Projected Noise Level, L_{dn}
LT-2 (closest residence)	65 dBA Exterior 45 dBA Interior	43 dBA Exterior 26 dBA Interior
ST-4 (Tule Elk Reserve)		37 dBA Exterior 20 dBA interior
ST-5 (second closest residence)		42 dBA Exterior 25 dBA Interior

Source: Kern County 2007 and HECA 2012a, AFC § 5.5.2.3, Tables 5.5-28 and 5.5-29.

As seen in **Noise and Vibration Table 4** above, operational noise levels would be below County standards at the project's most noise-sensitive receptors. Thus, the project would comply with the noise LORS.

CEQA Impacts

Noise from stationary industrial sources such as power plants and other systems and equipment that would be employed in HECA is unique. Essentially, such sources operate as steady, continuous, broadband noise sources, unlike the intermittent sounds that comprise the majority of the noise environment. As such, the noise from these industrial sources contributes to, and becomes part of, the background noise level, or the sound heard when most intermittent noises cease. Where this noise is audible, it will tend to define the background noise level. For this reason, staff compares the projected facility noise to the existing ambient background (L_{90}) noise levels at the affected sensitive receptors. If this comparison identifies a significant adverse impact, then feasible mitigation must be incorporated in the project to reduce or remove the impact.

For residential receptors, staff evaluates project noise emissions by comparing them with nighttime ambient background levels; this evaluation assumes that the potential for public annoyance from project noise is greatest at night when residents are trying to sleep. Nighttime ambient noise levels are typically lower than daytime levels; differences in background noise levels of 5 to 10 dBA are common. Staff believes it is prudent to average the lowest nighttime hourly background noise levels to arrive at a reasonable baseline for comparison with the project's predicted noise level.

Adverse impacts on residential receptors can be identified by comparing predicted project noise levels with the nighttime ambient background noise levels at the nearest sensitive residential receptors.

The applicant has predicted operational noise levels; they are summarized here in **Noise and Vibration Table 5**.

Noise and Vibration Table 5
Predicted Operational Noise Levels and CEQA

Receptor	Project Alone Operational Noise Level L_{90} (dBA) [1]	Measured Existing Ambient, Average Nighttime L_{90} (dBA) [2]	Project Plus Ambient L_{90} (dBA)	Change in Ambient Level
LT-2	37	30	38	+8
ST-5	36	33	38	+5

[1] Source: HECA 2012a, AFC § Table 5.5-30; staff calculations
[2] Source: **Noise and Vibration Table 2**

Combining the ambient noise level of 30 dBA L_{90} at LT-2 (**Noise and Vibration Table 5**, above) with the project noise level of 37 dBA L_{90} would result in a level of 38 dBA L_{90}, 8 dBA over the ambient. Combining the ambient noise level of 33 dBA L_{90} at ST-5 with the project noise level of 36 dBA L_{90} would result in a level of 38 dBA L_{90}, 5 dBA over ambient. As described above (in **Method and Threshold for Determining Significance**), staff regards an increase of up to 5 dBA as a less-than-significant impact and between 5 dBA and 10 dBA as a potentially significant impact. However, the California Model Community Noise Control Ordinance recommendations specify a noise level of 40 dBA to be typical for rural environments. Given that the project would create an increase in ambient noise less than 10 dBA at the nearby receptors and the cumulative noise level (project plus ambient level) would be within the recommended noise level for rural environments (40 dBA), staff considerers the project noise impact to be less-than-significant.

To ensure these noise levels are not further exceeded, staff proposes Condition of Certification **NOISE-4**, below. This condition of certification requires a noise survey when project becomes operational. If the survey shows the project to be out of compliance with these noise levels, the project owner must then implement effective mitigation measures to bring the project into compliance with these levels.

Tonal Noises

One possible source of disturbance would be strong tonal noises. Tonal noises are individual sounds (such as pure tones) that, while not louder than permissible levels, stand out in sound quality. The applicant would avoid the creation of annoying tonal (pure-tone) noises by balancing the noise emissions of various project features during project design. To ensure that tonal noises do not cause annoyance, staff proposes Condition of Certification **NOISE-4**, below.

Linear Facilities

Natural gas, water and carbon dioxide piping would lie underground and would be silent during operation. Noise effects from the electrical interconnection line typically do not extend beyond the right-of-way easement of the line and would thus be inaudible to any receptors.

Vibration

Vibration from HECA could be transmitted by two chief means; through the ground (groundborne vibration) and through the air (airborne vibration).

The individual components that would be employed in the HECA project have demonstrated a very low probability for either ground-borne or airborne-induced vibration impacts to surrounding land uses. All of these pieces of equipment are carefully balanced in order to operate; permanent vibration sensors are attached to the turbines and generators. Should an imbalance occur, the event will be detected and the equipment will automatically shut down. Also, given the distances from the actual equipment to the nearest receptor locations (on the order of at least 3,000 feet), vibration from HECA would be undetectable by any likely receptor.

Vibration Due to the Rail Spur

The FTA Criteria of Impact for Human Annoyance and Interference due to Ground-Borne Vibration is used to determine the threshold for vibration impacts due to the proposed railroad spur centerline (AFC 2012a, Table 5.5-14). MR-1 and MR-2 are noise-sensitive receptors located west of the proposed railroad spur centerline. MR-2 was not analyzed due to the presence of the canal between the source and the receiver.

Assuming a worst-case scenario for train operations, the train would arrive and leave the project site via the proposed railroad spur once a day for a total of two train events. According to FTA vibration criteria, this is considered to be “infrequent.” The receptor at MR-1 is a Category 2 receptor, and therefore the vibration impact threshold is 80 VdB (HECA 2012a, AFC Table 5.5-14). It is important to note that the threshold for human perception of vibration is 65 VdB. The vibration level at MR-1 would be 67 VdB, slightly perceived, but below the 80 VdB requirement. Thus, the vibration impact due to the rail spur would be in compliance with the applicable LORS.

Worker Effects

The applicant has acknowledged the need to protect the facility’s operating and maintenance workers from noise hazards and has committed to comply with applicable LORS (HECA 2012a, AFC § 5.5.2.5). The project would specify that nearly all components would not exceed a near-field maximum noise level of 80 dBA at 1 meter (3 feet) as the standard for equipment selection and procurement. Additionally, signs would be posted in areas of the facility with noise levels exceeding 85 dBA (the level that OSHA recognizes as a threat to workers’ hearing), and hearing protection would be required. To ensure that operation and maintenance workers are, in fact, adequately protected, Energy Commission staff has proposed Condition of Certification **NOISE-5**, below.

Traffic Noise

HECA is unique from previous power facilities that have gone through the Energy Commission’s siting process in that the need for delivery of fuel feedstock would continue for the life of the project. In addition to the normal medium and heavy truck traffic expected during construction, which would extend for approximately 3.5 years (HECA 2012a, § 2.1.7), the applicant proposes two alternative transportation schemes for delivery of feedstock to the project site: 1. Deliver coal feedstock via rail transport over a new 5-mile spur track (Alternate 1), while delivering the balance of operational materials by truck and on existing transportation routes; or 2. Deliver all project supplies, including coal feedstock from Wasco, via trucks, on existing transportation routes (Alternative 2). Please see Data Response Figure A63-1 for a map showing the routes.

The applicant has analyzed the impact of traffic noise using methods used by the FTA[5] and has analyzed the traffic impact at identified receptors from Wasco to the project site (HECA 2012a, AFC Tables 5.5-33, 5.5-35). Using a traffic density metric called Annual Average Daily Traffic (AADT or ADT), the applicant has used the 2010 ADT for the various transportation routes terminating at the project site. By assuming that the ADT increases at an annual rate of 2%, baseline traffic densities were calculated for a “2016” construction year and “2017” operational year at the intersections along the assumed routes to establish baseline ADTs (HECA 2012b, Response to Data Request A-159, Tables A159-1 through A159-3, October 2012). The project transportation requirements were added to these ADTs to calculate the project’s traffic contribution (HECA 2012a, AFC Tables 5.10-4 and 5.10-5).

Since traffic is analyzed as a 24-hour impact, the noise analysis uses the L_{dn}/CNEL metric, which applies a weighted average to the hourly L_{eq} values, accounting for community sensitivity to nighttime noise when people are trying to sleep, to determine the “without project” baseline and the “with project” construction and operational impacts. All of the sensitive receptors within proximity to the intermediary intersections are evaluated against 65 dBA L_{dn}, the threshold levels defined in the Kern County Noise Element[6] and the City of Wasco Noise Element[7]. The differential threshold of 3 dBA were also selected because it represents a change in noise level perceptible to the ear and is consistent with the FTA-defined value at 65 dBA for moderate to severe impact (HECA 2012a, Figure 5.5-2).

The results of the project impact on traffic are presented in the AFC Tables 5.5-33 “2016 Construction Traffic Noise Results, 5.5-34 “2017 Operational Traffic Noise Results” (Rail Option, or Alternative 1), and 5.5-34 “2017 Industrial Operation Traffic No Rail Scenario Noise Results” (Truck Option, or Alternative 2). Based on the 65 dBA limit and the 3 dBA differential (65/3), there were three impact locations during the construction phase of work, two during the operational/rail option phase, and six during the operational/truck option. These results are summarized in **Noise and Vibration Table 6** below.

Traffic - Project Construction

To determine noise attributable to moving traffic, typical noise levels based on ADT, mixture of vehicle type (auto, medium-duty and heavy-duty trucks) and speed are assessed in terms of the L_{dn}/CNEL metric, which is a 24-hour weighted and cumulative value. The traffic attributable to the project construction activities are added to the vehicular flow going into and out of an intersection or interchange. For this reason, the modeling at each intersection is broken down to north, south, east and west quadrants, which represent traffic density. Thus, the traditional method of identifying sound power levels and calculating the attenuated noise to a sensitive receptor does not adequately

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[5] Federal Transit Administration (FTA) Transit Noise and Vibration Impact Assessment Manual (FTA-VA-90-1003-06)

[6] Kern County General Plan, Noise Element Chapter 3, § 3.2, Policy 5, p. 148.

[7] City of Wasco General Plan, Noise Element Chapter 8, § 8.1 Project Evaluatio, Policy 1, p. 8.0-1.

represent the noise conditions. Instead, the baseline and projected L_{dn} or CNEL would have to apply at full noise levels to residences, community buildings and other building types along the path of the road.

In the case of construction traffic for HECA, the 65 dBA L_{dn} threshold and 3 dBA increment (65/3) are identified as delineated in the AFC Table 5.5-33. Where the calculated noise levels exceed the 65/3 criterion, the noise levels at any structures along the street or highway path would experience a significant increase in exposure to noise (**Noise and Vibration Table 6** below).

Noise and Vibration Table 6
"With Project" Truck Traffic Noise Levels at Intersections - Alternative 2

Mark	Intersection	Table	Orientation	Speed (mph)	Additional Vehicles	Noise Level (L_{dn}) dBA	Increment (L_{dn}) dBA
OPS-2.1 1	I-5 North/ Stockdale	5.5-35	West	55	490	70	3
OPS-2.2 2	I-5 South/ Stockdale	5.5-35	East	55	490	70	3
C-1 3	I-5 South/ Stockdale	5.5-33	West	55	2024	67	3
OPS-1.1 4	I-5 South/ Stockdale	5.5-34	West	55	457	67	3
OPS-2.3 5	I-5 South/ Stockdale	5.5-35	West	55	490	70	5
OPS-2.4 6	Stockdale/ Morris	5.5-35	South 4300'W LT-3	25	490	65	19
C-2 7	Stockdale/ Morris	5.5-33	East 4300'W LT-3	55	2022	67	3
OPS-1.2 8	Stockdale/ Morris	5.5-34	East 4300'W LT-3	55	456	67	3
OPS-2.5 9	Stockdale/ Morris	5.5-35	East 4300'W LT-3	55	490	70	5
OPS-2.6 10	Tupman/ Station	5.5-35	East 1800'E LT-2	25	490	65	18
C-3 11	Dairy/ Stockdale	5.5-33	West 3200'W LT-9	55	320	67	3

From the applicant's analysis, there are three locations where project construction would have the potential to cause a significant impact: Interstate 5 and Stockdale (C-1), Stockdale and Morris (C-2), and Dairy and Stockdale (C-3) (see **Noise and Vibration Table 6** above) (HECA 2012a, AFC § 5.5.2.8, Table 5.5-33). The west leg of the intersection of Dairy Road and Stockdale Highway would have an increase in L_{dn}/CNEL of 3 dBA with a resulting noise level of 67 dBA L_{dn}/CNEL at 50 feet due to construction traffic related to the project. There are two residences located along the north side of Stockdale Highway that would be impacted during construction. The east leg of the intersection of Stockdale Highway and Morris Road would be impacted and would see an increase in L_{dn}/CNEL of 3 dBA with resulting noise level of 67 dBA L_{dn}/CNEL at a distance of 50 feet due to construction traffic related to the project. There are no residences close enough to this intersection to be considered impacted. The west leg of the intersection of Interstate-5 SB Ramp and Stockdale Highway would be impacted and would see an increase in L_{dn}/CNEL of 3 dBA with a resulting noise level of 67 dBA

L_{dn}/CNEL at 50 feet due to construction traffic related to the project. There are no residences close enough to this leg to be considered impacted.

The applicant concluded that as long as construction traffic is limited to construction noise exempt hours, noise impacts could be considered intermittent and temporary (HECA 2012a, p. 5.5-31). However, the HECA construction period would be approximately 3.5 years long; the period of noise exposure from construction noise extends beyond the reasonable understanding of "intermittent and temporary." For this reason, staff concludes that mitigation measures must be implemented to reduce significant traffic noise at any affected noise-sensitive receptors near the construction traffic pathways. To reduce the impact on noise-sensitive receptors along the pathway to less than significant, staff proposes Condition of Certification **NOISE-9**, which would require reduced speed limits, soundwalls, and/or roadway improvements. With implementation of this Condition of Certification, construction traffic noise would comply with the LORS and would create a less-than-significant impact.

NOISE-9 would require a noise survey once construction is underway, to determine if the noise impact needs to be mitigated at any effected receptor located within 1,000 feet of the transportation route from Wasco, CA to the project site. Although, it may be somewhat premature to, prior to commencement of project-related traffic, identify the receptors where soundwalls would be installed, it would be helpful to at least have a general idea of where these soundwalls might be installed so that the other technical staff could weigh in on whether impacts from their installation could be significant. Therefore, prior to preparing the FSA/FEIS, the applicant needs to inform staff of the potential locations of the soundwalls, including their height and length.

Traffic - Project Operation

Coal by Rail (Alternative 1)

A new 5-mile rail spur would connect the HECA site with an existing San Joaquin Valley Railroad (SJVRR) spur track, which runs in a right of way along side of State Route 58 (Rosedale Highway). This rail spur would provide an average 2-unit trip per week. One train unit would comprise 111 coal cars and five locomotives. The balance of transport would be handled by trucks delivering petcoke from southern and central California, delivering at a rate of 55 trucks per day. The frequency for delivering chemicals, products and parts would vary. Modeling of truck traffic attributable to project operation utilizes the same method as the one used for construction traffic. Material load types and numbers would shift to account for operational activities (HECA 2012a, AFC Tables 5.10-4 and 5.5.34) and an increased ADT would project forward to 2017.

From the applicant's analysis of truck runs, there are two locations where the project exceeds the 65/3 criteria: Interstate 5 South and Stockdale (see OPS-1.1 in **Noise and Vibration Table 6**) and the Stockdale/Morris intersection (OPS-1.2). Both of these locations have a baseline L_{dn} of 64 dBA with a 3 dBA increment for a final L_{dn} of 67 dBA. The Interstate 5/Stockdale interchange is remote to the project. Stockdale/Morris is closer in toward the project site and has sensitive receptor LT-3/ST-3 within its sphere of influence (see **Noise and Vibration Figure 1**). Although the noise levels at the remaining intersections closer to the project site do not exceed the 65 dBA threshold, the incremental increased noise levels are notable: 13 dBA easterly at Tupman and

Station, 10 dBA at Dairy and Stockdale and 15 dBA northerly/20 dBA southerly. As seen here, the potential to create a significant noise impact at some of the receptors would exist. Thus, staff proposes Condition of Certification **NOISE-9** to reduce any significant impacts to less than significant. This condition of certification would require a noise survey at any noise-sensitive receptor within 1,000 feet of the path of travel. If the survey shows the train noise to be out of compliance with the FTA criteria for a severe impact, the project owner must then implement effective mitigation measures to bring the project into compliance with these criteria. These measures include reduced speed limits, soundwalls, and/or roadway improvements.

The applicant assessed the railroad spur using the FTA Noise Impact Assessment Spreadsheet model. The results are summarized in AFC Table 5.5-31. The baseline noise levels were measured at LT-7 at L_{dn} of 65 dBA and applied to MR-1 (see Data Response Figure A199-1, docketed on January 16, 2013). The cumulative effect of the train increased to 67 dBA. The 2 dBA differential was considered moderate impact under FTA guidelines (HECA 2012a, AFC Figure 5.5-2). The existing L_{dn} of 53 dBA was measured at LT-8, which was applied to MR-2. The cumulative L_{dn} of 53 dBA at LT-8 was unchanged from baseline conditions. The cumulative L_{dn} at MR-2 was 59 dBA, a 6 dBA difference having a moderate impact by FTA standards. The LT-9 L_{dn} remained unchanged at 67 dBA, having no impact. The cumulative L_{dn} of 67 dBA derived for MR-1 is the only location that exceeds the 65 dBA criterion. LT-9 remains unchanged at L_{dn} of 67 dBA. Among the measured and derived receptors, MR-1 is the only location to exceed 65 dBA and its differential impact is only “moderate”.

The rail spur would provide an average 2-unit trip per week. There would be 5 private crossings and 2 public crossings, at which the train would initiate a 20-second warning as it approaches a public crossing. Noise analysis for the train, including the whistle noise is covered in AFC § 5.5.2.6 and Table 5.5-31. Based on the train length of 1.3 miles and a speed of 25 mph, the train would signal a 20-second warning, followed by a three-minute travel time between Stockdale Road and Adohr Road along Dairy Road, followed by a 20-second warning as it enters the second public crossing. Based on AFC Table 5.5-31, the whistle noise would be below the existing background noise level at the nearest noise-sensitive receptor, LT-9. Additionally, while the tonal quality of the whistle may make it a distinctive sound separate from other background noise, its characteristics would be intended for the purpose of safety. Therefore, the noise impact of train horn would be less than significant.

Coal by Truck (Alternative 2)

Alternative 2 eliminates the option to construct and operate a railroad spur to deliver coal feedstock directly to HECA. The applicant’s analysis extends all the way back to the city of Wasco, where a coal terminal is located. The truck count for this operational alternative is provided in AFC Table 5.10-5 and the analysis is summarized in Table 5.5-35, using projected ADTs for 2017.

From the applicant’s analysis, the “Truck Only” option would have the potential to cause a significant impact at six locations. Three are located at the Interstate 5/Stockdale Interchange. The west leg of the intersection of the I-5 northbound ramp and Stockdale Highway would be impacted and would have both an increase in L_{dn}/CNEL of 3 dBA and a “with project” L_{dn}/CNEL of greater than 65 dBA at a distance of 50 feet from the centerline. Noise-sensitive residential homes are located as close as 60 feet to the centerline along this leg (see OPS-2.1, OPS-2.2, and OPS-2.3 in **Noise and Vibration Table 6**). Two of the remaining three are located at the intersection of Stockdale and Morris (OPS-2.4 and OPS-2.5), which is 4,300 feet from LT-3. The south orientation measures out at an initial L_{dn} of 46 dbA and a final of 65 dBA (19 dBA difference). In the easterly direction, the noise levels are an L_{dn} of 65 dBA initial, 70 dBA final for a 5 dBA difference. The final significant location is Tupman at Station (OPS-2.6) with an initial L_{db} of 47 dBA and an 18 dBA change to finish at 65 dBA. This location is 1,800 feet from LT-2. Tule Elk Reserve's visitor center is located approximately 300 feet south of Station Road and would likely experience a high level of noise from truck traffic. As seen here, the potential to create a significant noise impact at some of the receptors would exist. Thus, staff proposes Condition of Certification **NOISE-9** to reduce any significant impacts to less than significant.

The EOR Facility

Supplemental Environmental Information (SEI) prepared for the Occidental of Elk Hills, Inc. (OEHI) (SEI 2012) evaluates the noise and vibrations impacts of EOR on the nearest noise-sensitive receptors. Table 4.11-3 of the SEI lists the sensitive receptors in close proximity to EOR. The closest noise-sensitive receptor to EOR is located in the Town of Tupman, approximately 1.5 miles northeast of the EOR site. The existing average ambient noise level at this location is 61.0 dBA L_{dn} (SEI 2012, Table 4.11-7). Project construction noise level would be 61.2 dBA L_{dn} at this location, only 0.2 dBA above existing ambient. Noisy construction work within 1,000 feet of a noise-sensitive receptor would be allowed only during the daytime hours of 6:00 a.m. to 9:00 p.m. weekdays and 8:00 a.m. to 9:00 p.m. weekends in compliance with the Kern County code. Therefore, the noise impacts of EOR construction activities would comply with the noise LORS and would create a less-than-significant impact. To ensure that these hours are, in fact, enforced, staff recommends that the agency with responsibility for OEHI implement mitigation restricting construction to these specified hours (please see **Recommended Mitigation Measures** below). Staff does not know which agency would have jurisdiction over OEHI but will discover that and include it in the FSA/FEIS).

Operation of the EOR facility would have the potential to impact the nearest sensitive receptor in the Town of Tupman. Noise from this facility's operations would result in 61.2 dBA L_{dn} (SEI 2012, Table 4.11-7). This is only 0.2 dBA in excess of existing ambient and is below the county's threshold of 65 dBA L_{dn}. Thus, the noise impacts of EOR operational activities would comply with the noise LORS and would create a less-than-significant impact.

The most likely activity that could result in groundborne vibrations would be the operation of conventional construction equipment involved in installation of pipelines and the EOR processing facility. Vibration from typical earthmoving activity generally dissipates rather quickly above distances of approximately 100 feet. Given the one mile distance of the nearest construction site to a sensitive receptor, excessive groundborne vibration would be very unlikely. Project operation would not include components that have proven to cause vibrations at such a distance.

CUMULATIVE IMPACTS AND MITIGATION

Section 15130 of the CEQA Guidelines (Cal. Code Regs., tit. 14) requires a discussion of cumulative environmental impacts. Cumulative impacts are two or more individual impacts that, when considered together, are considerable or that compound or increase other environmental impacts. The CEQA Guidelines require that the discussion reflect the severity of the impacts and the likelihood of their occurrence, but need not provide as much detail as the discussion of the impacts attributable to the project alone.

There is one project in the vicinity of HECA, a proposed dairy farm and milk production facility that may occupy plots to the west, north and east of the HECA project site (HECA 2012a, AFC § 5.5.3, Appendix J). The onsite noise from the dairy farm is estimated to range from 57 to 67 dBA. Considering the fairly low onsite noise levels from the dairy facility and the relatively long distances to the nearest noise-sensitive receptors, the dairy facility is expected to contribute negligible, if any, additional noise levels to the environment around the project site. Thus, the combined noise from HECA and the farm facility would not pose a potential for significant cumulative noise impacts.

The HECA and EOR facilities would be approximately 2.5 miles apart. The noise-sensitive receptor most likely to be affected by the combined noise from these two facilities is located on the western edge of the Town of Tupman, approximately 1.5 miles northeast of the EOR site and approximately 1.5 miles southeast of the HECA site. Operation of HECA would likely generate a noise level of 25 dBA L_{eq} at this location (**Noise and Vibration Figure 1**). Operation of the EOR facility would likely generate a noise level of 62.2 dBA L_{eq} (SEI 2012, § 4.11.5). The additive noise level of these two sources is 62.2 dBA L_{eq}. This means that the addition of HECA would not increase the impact; or, HECA would not be heard at this receptor. Thus, the combined noise from HECA and EOR would not pose a potential for significant cumulative noise impacts.

FACILITY CLOSURE

In the future, upon closure of HECA, all operational noise from the project would cease, and no further adverse noise impacts from operation of HECA would be possible. The remaining potential temporary noise source would be the dismantling of the structures and equipment and any site restoration work that may be performed. Since this noise would be similar to that caused by the original construction, it can be treated similarly. That is, noisy work could be performed during daytime hours, with machinery and equipment properly equipped with mufflers. Any noise LORS that are in existence at that time would apply. Applicable conditions of certification included in the Energy Commission decision would also apply.

DOE'S FINDINGS REGARDING DIRECT AND INDIRECT IMPACTS OF THE NO-ACTION ALTERNATIVE

Under the No-Action Alternative, DOE would not provide financial assistance to the applicant for HECA. The applicant could still elect to construct and operate its project in the absence of financial assistance from DOE, but DOE believes this is unlikely. For the purposes of analysis in the PSA/DEIS, DOE assumes the project would not be constructed under the No-Action Alternative. Accordingly, the No-Action Alternative would have no impacts associated with this resource area.

CONCLUSIONS AND RECOMMENDATIONS

Staff concludes that HECA, if built and operated in conformance with the proposed conditions of certification below, would comply with all applicable noise and vibration LORS and would produce no significant adverse noise impacts on people within the project area, including the identified environmental justice population, directly, indirectly, or cumulatively.

PROPOSED CONDITIONS OF CERTIFICATION

NOISE-1 At least 15 days prior to the start of ground disturbance, the project owner shall notify all noise-sensitive receptors[8] within 1.5 miles of the HECA site boundaries, and all noise-sensitive receptors within 1,000 feet of the project-related traffic routes, including the personnel at the Tule Elk State Natural Reserve's visitor center by mail or other effective means, of the commencement of project construction. At the same time, the project owner shall establish a telephone number for use by the public to report any undesirable noise conditions associated with the construction and operation of the project and include that telephone number in the above notice. If the telephone is not staffed 24 hours per day, the project owner shall include an automatic answering feature, with date and time stamp recording, to answer calls when the phone is unattended. This telephone number shall be posted at the project site during construction in a manner visible to passersby. This telephone number shall be maintained until the project has been operational for at least one year.

<u>Verification:</u> Prior to ground disturbance, the project owner shall transmit to the compliance project manager (CPM) a statement, signed by the project owner's project manager, stating that the above notification has been performed and describing the method of that notification, verifying that the telephone number has been established and posted at the site, and giving that telephone number.

NOISE COMPLAINT PROCESS

NOISE-2 Throughout the construction and operation of HECA, the project owner shall document, investigate, evaluate, and attempt to resolve all project-related noise complaints, including complaints due to project-related traffic. The project owner or authorized agent shall:

- Use the Noise Complaint Resolution Form (below), or a functionally equivalent procedure acceptable to the CPM, to document and respond to each noise complaint;

[8] A sensitive noise receptor, also referred to as a noise-sensitive receptor, is a receptor at which there is a reasonable degree of sensitivity to noise (such as residences, schools, hospitals, elder care facilities, libraries, cemeteries, and places of worship).

- Attempt to contact the person(s) making the noise complaint within 24 hours;
- Conduct an investigation to determine the source of noise related to the complaint;
- Take all feasible measures to reduce the noise at its source if the noise is project related; and
- Submit a report documenting the complaint and the actions taken. The report shall include: a complaint summary, including final results of noise reduction efforts, and if obtainable, a signed statement by the complainant stating that the noise problem is resolved to the complainant's satisfaction.

Verification: Within five days of receiving a noise complaint, the project owner shall file a copy of the Noise Complaint Resolution Form with the CPM, documenting the resolution of the complaint. If mitigation is required to resolve a complaint, and the complaint is not resolved within a three-day period, the project owner shall submit an updated Noise Complaint Resolution Form when the mitigation is implemented.

NOISE-3 The project owner shall submit to the CPM for review and approval a noise control program and a statement, signed by the project owner's project manager, verifying that the noise control program will be implemented throughout construction of the project. The noise control program shall be used to reduce employee exposure to high noise levels during construction and also to comply with applicable OSHA and Cal/OSHA standards.

Verification: At least 30 days prior to the start of ground disturbance, the project owner shall submit to the CPM the noise control program and the project owner's project manager's signed statement. The project owner shall make the program available to Cal/OSHA upon request.

NOISE RESTRICTIONS

NOISE-4 The project design and implementation shall include appropriate noise mitigation measures adequate to ensure that the noise levels due to operation of the project alone will not exceed: an hourly average of 37 dBA L_{90}, measured at or near monitoring location LT-2 and an hourly average of 36 dBA L_{90}, measured at or near monitoring location ST-5.

No new pure-tone components shall be caused by the project. No single piece of equipment shall be allowed to stand out as a source of noise that draws legitimate complaints.

A. When the project first achieves full operation, the project owner shall conduct a 25-hour community noise survey at monitoring location LT-2, or at a closer location acceptable to the CPM. This survey shall also include measurement of one-third octave band sound pressure levels to ensure that no new pure-tone noise components have been caused by the project.

   During the period of this survey, the project owner shall conduct a short term survey of noise at monitoring location ST-5, or at closer locations acceptable to the CPM. The short-term noise measurements at this location shall be conducted during the nighttime hours of 10:00 p.m. to 7:00 a.m.

The measurement of project noise for the purposes of demonstrating compliance with this condition of certification may alternatively be made at a location, acceptable to the CPM, closer to the project (e.g., 400 feet from the project boundary) and this measured level then mathematically extrapolated to determine the project noise contribution at the affected residence. The character of the project noise shall be evaluated at the affected receptor locations to determine the presence of pure tones or other dominant sources of project noise.

B. If the results from the noise survey indicate that the power project noise at the affected receptor sites exceeds the above noise limits, mitigation measures shall be implemented to reduce noise to a level of compliance with these limits.

C. If the results from the noise survey indicate that pure tones are present, mitigation measures shall be implemented to eliminate the pure tones.

Verification: The survey shall take place within 30 days of the project first achieving full operation. Within 15 days after completing the survey, the project owner shall submit a summary report of the survey to the CPM. Included in the survey report shall be a description of any additional mitigation measures necessary to achieve compliance with the above listed noise limits, and a schedule, subject to CPM approval, for implementing these measures. When these measures are in place, the project owner shall repeat the noise survey.

NOISE-5 Following the project's first achieving full operation, the project owner shall conduct an occupational noise survey to identify the noise hazardous areas in the facility.

The survey shall be conducted by a qualified person in accordance with the provisions of Title 8, California Code of Regulations sections 5095–5099 and Title 29, Code of Federal Regulations section 1910.95. The survey results shall be used to determine the magnitude of employee noise exposure.

The project owner shall prepare a report of the survey results and, if necessary, identify proposed mitigation measures that will be employed to comply with the applicable California and federal regulations.

Verification: Within 30 days after completing the survey, the project owner shall submit the noise survey report to the CPM. The project owner shall make the report available to OSHA and Cal/OSHA upon request.

STEAM BLOW RESTRICTIONS

NOISE-6 If a traditional, high-pressure steam blow process is employed, the project owner shall perform the steam blow in such a way that noise from steam blows is no greater than 109 dBA measured at a distance of 100 feet. The project owner shall conduct steam blows only during the hours of 8 a.m. to 6 p.m., unless the CPM agrees to longer hours based on a demonstration by the project owner that offsite noise impacts will not cause annoyance. If a low-pressure continuous steam blow process is employed, the project owner shall submit a description of this process, with expected noise levels and projected hours of execution, to the CPM.

Verification: At least 15 days prior to the first high-pressure steam blow, the project owner shall submit to the CPM a projection of the noise levels expected, and a description of the steam blow schedule. At least 15 days prior to any low-pressure continuous steam blow, the project owner shall submit to the CPM drawings or other information describing the process, including the noise levels expected and the projected time schedule for execution of the process.

NOISE-7 Prior to the first steam blow(s), the project owner shall notify all residents or business owners within 1.5 miles of the project site boundaries of the planned steam blow activity, and shall make the notification available to other area residents in an appropriate manner. The notification may be in the form of letters to the area residences, telephone calls, fliers or other effective means. The notification shall include a description of the purpose and nature of the steam blow(s), the proposed schedule, the expected sound levels, and the explanation that it is a one-time operation and not a part of normal project operations.

Verification: This notification shall occur at least 15 days prior to the first steam blow(s). Within five days of notifying these entities, the project owner shall send a letter to the CPM confirming that they have been notified of the planned steam blow activities, including a description of the method(s) of that notification.

CONSTRUCTION TIME RESTRICTIONS

NOISE-8 Operation of heavy construction equipment and noisy construction work relating to any project features, including construction-related traffic, shall be restricted to the times delineated below, if the activity occurs within 1,000 feet of a noise sensitive receptor:

Weekdays:	6:00 a.m. to 9:00 p.m.
Weekends:	8:00 a.m. to 9:00 p.m.

Haul trucks and other engine-powered equipment shall be equipped with mufflers that meet all applicable regulations. Haul trucks shall be operated in accordance with posted speed limits. Truck engine exhaust brake use shall be limited to emergencies.

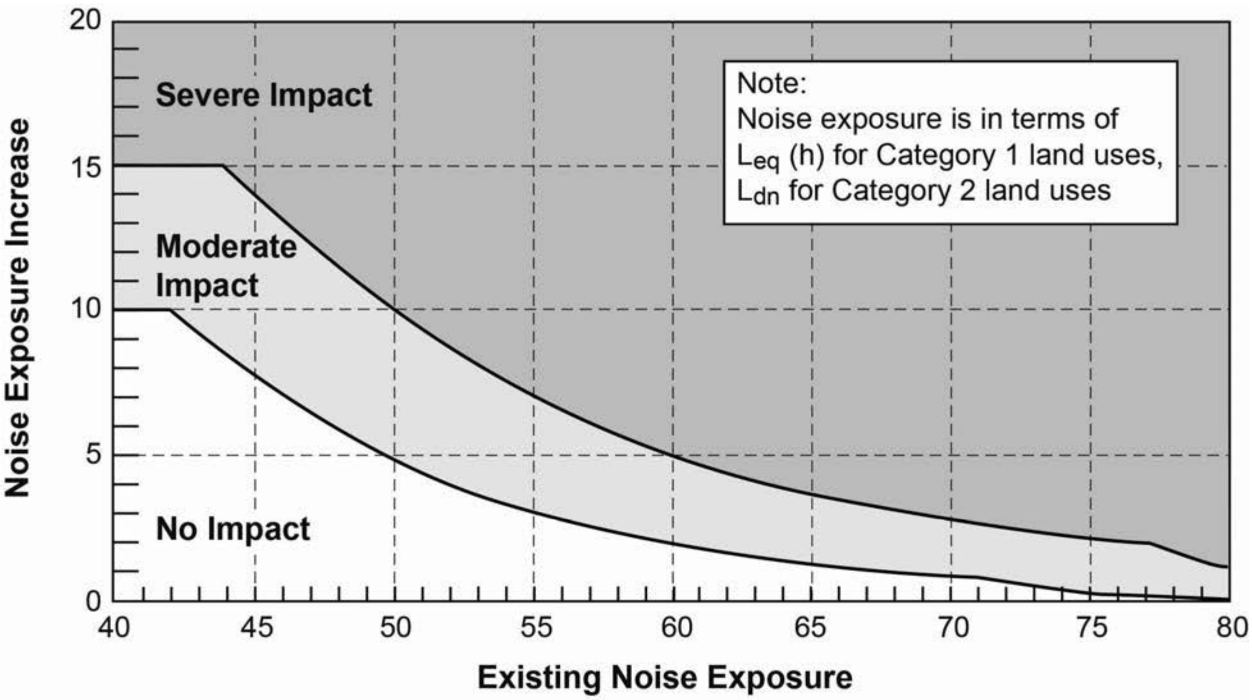
Verification: Prior to ground disturbance, the project owner shall transmit to the CPM a statement acknowledging that the above restrictions will be observed throughout the construction of the project.

TRAFFIC

NOISE-9 The project owner shall measure project-related traffic noise levels at all identified noise-sensitive receptors (or their representative location[s]) within

1,000 feet of the project's transportation routes, from Wasco, CA to the project site, including the Tule Elk State Natural Reserve's visitor center. The measurement of noise for the purposes of demonstrating compliance with this condition of certification may alternatively be made at a location, acceptable to the CPM, closer to the transportation route (e.g., 400 feet from the route) and this measured level then mathematically extrapolated to determine the noise contribution at the affected receptor(s).

If the measurements show noncompliance with the criteria outlined in the following graph, the project owner shall implement one or more of the following mitigation measures, in order to reduce the noise levels propagated by project-related construction and operation traffic at the affected receptor(s), to a level at or below the threshold for a "severe impact" as shown in the following graph.



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SOURCE: FTA Manual, Fig. 3.2 "Increase in Cumulative Noise Levels Allowed by Criteria (Land Use Categories 1 and 2)"

Category 1 shown in this graph applies to the Tule Elk State Natural Reserve and Category 2 shown in this graph applies to residences and buildings where people normally sleep, including homes, hospitals and hotels.

Mitigation Measures:

a. The project owner shall request that Kern County reduce posted traffic speeds on the portion of the project's transportation route near the affected receptor. While it is the intent to reduce the noise from project-related traffic, the reduced posted speed limit shall be a part of traffic and congestion management and not create any unsafe conditions on the portions of the roadway that have reduced speeds and the newly created speed limit transitions portions of the roadway. The project owner shall make all reasonable efforts to provide the county the information needed, and to assist the county in evaluating and implementing a reduced speed. The reduced speed limit is intended for the duration of the construction and operation period.

b. The project owner shall construct a soundwall along the portion of the project's transportation route near the affected receptor. The wall shall be of adequate construction and materials to be safe and effective for the duration of project construction and operation.

c. The project owner shall pay for roadway improvements, along the portion of the project's transportation route near the affected receptor. Examples of such improvements include repaving the road, and changing out traffic lights to smooth out the flow of traffic and to eliminate the need for frequent stops and starts.

   After implementing the mitigation measure(s), the project owner shall perform a noise survey at the affected receptor(s) to ensure compliance with the appropriate noise level requirement as determined from the above graph.

Verification: If mitigation measure a. is to be implemented, the project owner shall notify the CPM of a formal request to Kern County to reduce posted speed limits, and provide a copy of the request to the CPM. This notification shall describe the expected noise level reduction at the affected receptor location, resulting from the implementation of this mitigation measure.

If mitigation measure b. is to be implemented, 15 days prior to construction of the soundwall, the project owner shall submit to the CPM for review and approval a portfolio of the soundwall design specifying the expected reduction in noise level at the affected receptor location, resulting from the implementation of this mitigation measure.

If mitigation measure c. is to be implemented, 15 days prior to start of roadway improvements, the project owner shall submit to the CPM a letter specifying the expected reduction in noise level at the affected receptor location, resulting from the implementation of this mitigation measure.

Within 15 days after completing the post-mitigation survey, the project owner shall submit a summary report of the survey to the CPM.

RECOMMENDED MITIGATION MEASURES

Operation of heavy construction equipment and noisy construction work relating to EOR shall be restricted to the times delineated below, if the activity occurs within 1,000 feet of a noise sensitive receptor:

Weekdays:	6:00 a.m. to 9:00 p.m.
Weekends:	8:00 a.m. to 9:00 p.m.

Haul trucks and other engine-powered equipment shall be equipped with mufflers that meet all applicable regulations. Haul trucks shall be operated in accordance with posted speed limits. Truck engine exhaust brake use shall be limited to emergencies.

EXHIBIT 1 - NOISE COMPLAINT RESOLUTION FORM

Hydrogen Energy California Project
(08-AFC-8A)

NOISE COMPLAINT LOG NUMBER ________________________

Complainant's name and address:

Phone number: ________________________

Date complaint received: ________________________
Time complaint received: ________________________

Nature of noise complaint:

Definition of problem after investigation by project personnel:

Date complainant first contacted: ________________________

Initial noise levels at 3 feet from noise source _________ dBA Date: _____________
Initial noise levels at complainant's property: __________ dBA Date: ____________

Final noise levels at 3 feet from noise source: ________ dBA Date: _____________
Final noise levels at complainant's property: __________ dBA Date: ____________

Description of corrective measures taken:

Complainant's signature: ________________________ Date: ____________

Approximate installed cost of corrective measures: $ ____________
Date installation completed: ____________
Date first letter sent to complainant: ____________ (copy attached)
Date final letter sent to complainant: ____________ (copy attached)

This information is certified to be correct:

Facility Manager's Signature: ________________________

(Attach additional pages and supporting documentation, as required).

REFERENCES

Kern County 2007 – Kern County General Plan, Noise Element. March 13, 2007.

Kern County 2009 – Kern County Code of Ordinance, Title 8, Chapter 8.36: Noise Control. Effective November 3, 2009.

HECA 2012a – Hydrogen California LLC, 08-AFC-8A. Amended Application for Certification, Volumes 1, 2, and 3 dated May 02, 2012. Submitted to CEC/Docket Unit on 05/02/2012.

HECA 2012b – Response to Data Request A-159, Tables A159-1 through A159-3, dated October 2012

SEI 2012 – Supplemental Environmental Information (SEI) prepared for the Occidental of Elk Hills, Inc. for the CO_2 Enhanced Oil recovery Project dated April 2012.

Noise and Vibration Appendix A
Fundamental Concepts of Community Noise

To describe noise environments and to assess impacts on noise sensitive area, a frequency weighting measure, which simulates human perception, is customarily used. It has been found that "A-weighting" of sound intensities best reflects the human ear's reduced sensitivity to low frequencies and correlates well with human perceptions of the annoying aspects of noise. The A-weighted decibel scale (dBA) is cited in most noise criteria. Decibels are logarithmic units that conveniently compare the wide range of sound intensities to which the human ear is sensitive. **Noise and Vibration Table A1** provides a description of technical terms related to noise.

Noise environments and consequences of human activities are usually well represented by an equivalent A-weighted sound level over a given time period (L_{eq}), or by average day and night A-weighted sound levels with a nighttime weighting of 10 dBA (L_{dn}). Noise levels are generally considered low when ambient levels are below 45 dBA, moderate in the 45 to 60 dBA range, and high above 60 dBA. Outdoor day-night sound levels vary over 50 dBA depending on the specific type of land use. Typical L_{dn} values might be 35 dBA for a wilderness area, 50 dBA for a small town or wooded residential area, 65 to 75 dBA for a major metropolis downtown (e.g., San Francisco), and 80 to 85 dBA near a freeway or airport. Although people often accept the higher levels associated with very noisy urban residential and residential-commercial zones, those higher levels nevertheless are considered to be levels of noise adverse to public health.

Various environments can be characterized by noise levels that are generally considered acceptable or unacceptable. Lower levels are expected in rural or suburban areas than would be expected for commercial or industrial zones. Nighttime ambient levels in urban environments are about seven decibels lower than the corresponding average daytime levels. The day-to-night difference in rural areas away from roads and other human activity can be considerably less. Areas with full-time human occupation that are subject to nighttime noise, which does not decrease relative to daytime levels, are often considered objectionable. Noise levels above 45 dBA at night can result in the onset of sleep interference effects. At 70 dBA, sleep interference effects become considerable (U.S. Environmental Protection Agency, Effects of Noise on People, December 31, 1971).

To help the reader understand the concept of noise in decibels (dBA), **Noise and Vibration Table A2** illustrates common noises and their associated sound levels, in dBA.

Noise and Vibration Table A1
Definition of Some Technical Terms Related to Noise

Terms	Definitions
Decibel, dB	A unit describing the amplitude of sound, equal to 20 times the logarithm to the base 10 of the ratio of the pressure of the sound measured to the reference pressure, which is 20 micropascals (20 micronewtons per square meter).
Frequency, Hz	The number of complete pressure fluctuations per second above and below atmospheric pressure.
A-Weighted Sound Level, dBA	The sound pressure level in decibels as measured on a sound level meter using the A-weighting filter network. The A-weighting filter de-emphasizes the very low and very high frequency components of the sound in a manner similar to the frequency response of the human ear and correlates well with subjective reactions to noise. All sound levels in this testimony are A-weighted.
L_{10}, L_{50}, & L_{90}	The A-weighted noise levels that are exceeded 10%, 50%, and 90% of the time, respectively, during the measurement period. L_{90} is generally taken as the background noise level.
Equivalent Noise Level, L_{eq}	The energy average A-weighted noise level during the noise level measurement period.
Community Noise Equivalent Level, CNEL	The average A-weighted noise level during a 24-hour day, obtained after addition of 4.8 decibels to levels in the evening from 7 p.m. to 10 p.m., and after addition of 10 decibels to sound levels in the night between 10 p.m. and 7 a.m.
Day-Night Level, L_{dn} or DNL	The Average A-weighted noise level during a 24-hour day, obtained after addition of 10 decibels to levels measured in the night between 10 p.m. and 7 a.m.
Ambient Noise Level	The composite of noise from all sources, near and far. The normal or existing level of environmental noise at a given location.
Intrusive Noise	That noise that intrudes over and above the existing ambient noise at a given location. The relative intrusiveness of a sound depends upon its amplitude, duration, frequency, and time of occurrence and tonal or informational content as well as the prevailing ambient noise level.
Pure Tone	A pure tone is defined by the Model Community Noise Control Ordinance as existing if the one-third octave band sound pressure level in the band with the tone exceeds the arithmetic average of the two contiguous bands by 5 decibels (dB) for center frequencies of 500 Hz and above, or by 8 dB for center frequencies between 160 Hz and 400 Hz, or by 15 dB for center frequencies less than or equal to 125 Hz.

Source: Guidelines for the Preparation and Content of Noise Elements of the General Plan, Model Community Noise Control Ordinance, California Department of Health Services 1976, 1977.

Noise and Vibration Table A2
Typical Environmental and Industry Sound Levels

Noise Source (at distance)	A-Weighted Sound Level in Decibels (dBA)	Noise Environment	Subjective Impression
Civil Defense Siren (100')	140-130		Pain Threshold
Jet Takeoff (200')	120		Very Loud
Very Loud Music	110	Rock Music Concert	
Pile Driver (50')	100		
Ambulance Siren (100')	90	Boiler Room	
Freight Cars (50')	85		
Pneumatic Drill (50')	80	Printing Press Kitchen with Garbage Disposal Running	Loud
Freeway (100')	70		Moderately Loud
Vacuum Cleaner (100')	60	Data Processing Center Department Store/Office	
Light Traffic (100')	50	Private Business Office	
Large Transformer (200')	40		Quiet
Soft Whisper (5')	30	Quiet Bedroom	
	20	Recording Studio	
	10		Threshold of Hearing

Source: Handbook of Noise Measurement, Arnold P.G. Peterson, 1980

Subjective Response to Noise

The adverse effects of noise on people can be classified into three general categories:

- Subjective effects of annoyance, nuisance, dissatisfaction.
- Interference with activities such as speech, sleep, and learning.
- Physiological effects such as anxiety or hearing loss.

The sound levels associated with environmental noise, in almost every case, produce effects only in the first two categories. Workers in industrial plants can experience noise effects in the last category. There is no completely satisfactory way to measure the subjective effects of noise or of the corresponding reactions of annoyance and dissatisfaction, primarily because of the wide variation in individual tolerance of noise.

One way to determine a person's subjective reaction to a new noise is to compare the level of the existing (background) noise, to which one has become accustomed, with the level of the new noise. In general, the more the level or the tonal variations of a new noise exceed the previously existing ambient noise level or tonal quality, the less acceptable the new noise will be, as judged by the exposed individual.

With regard to increases in A-weighted noise levels, knowledge of the following relationships can be helpful in understanding the significance of human exposure to noise.

1. Except under special conditions, a change in sound level of 1 dB cannot be perceived.

2. Outside of the laboratory, a 3-dB change is considered a barely noticeable difference.

3. A change in level of at least 5 dB is required before any noticeable change in community response would be expected.

4. A 10-dB change is subjectively heard as an approximate doubling in loudness and almost always causes an adverse community response (Kryter, Karl D., The Effects of Noise on Man, 1970).

Combination of Sound Levels

People perceive both the level and frequency of sound in a non-linear way. A doubling of sound energy (for instance, from two identical automobiles passing simultaneously) creates a 3-dB increase (i.e., the resultant sound level is the sound level from a single passing automobile plus 3 dB). **Noise and Vibration Table A3** indicates the rules for decibel addition used in community noise prediction.

Noise and Vibration Table A3
Addition of Decibel Values

When two decibel values differ by:	Add the following amount to the larger value
0 to 1 dB	3 dB
2 to 3 dB	2 dB
4 to 9 dB	1 dB
10 dB or more	0
Figures in this table are accurate to ± 1 dB.	

Source: Architectural Acoustics, M. David Egan, 1988.

Sound and Distance

Doubling the distance from a noise source reduces the sound pressure level by 6 dB.

Increasing the distance from a noise source 10 times reduces the sound pressure level by 20 dB.

Worker Protection

OSHA noise regulations are designed to protect workers against the effects of noise exposure and list permissible noise level exposure as a function of the amount of time to which the worker is exposed, as shown in **Noise and Vibration Table A4**.

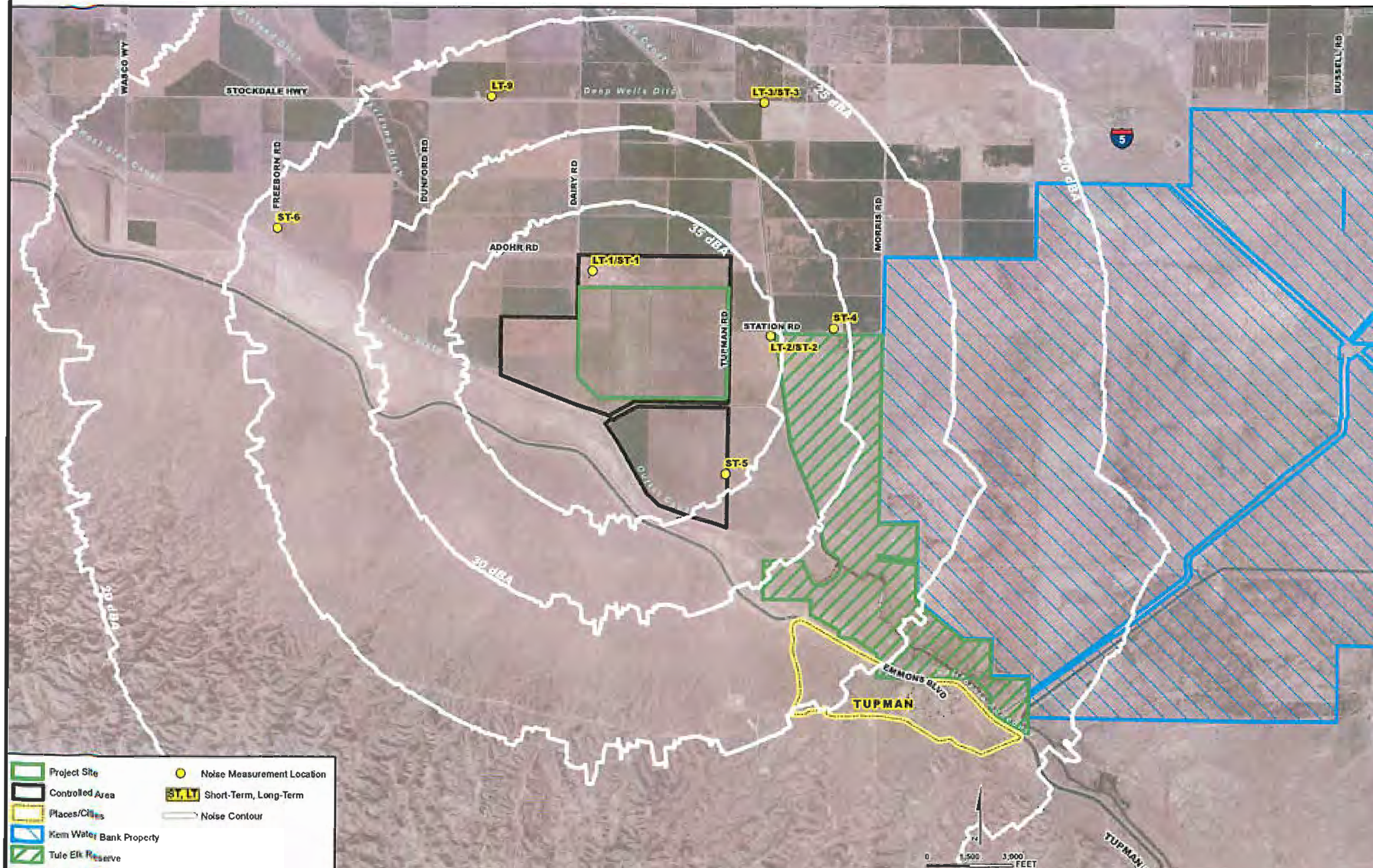
Noise and Vibration Table A4
OSHA Worker Noise Exposure Standards

Duration of Noise (Hrs/day)	A-Weighted Noise Level (dBA)
8.0	90
6.0	92
4.0	95
3.0	97
2.0	100
1.5	102
1.0	105
0.5	110
0.25	115

Source: 29 CFR § 1910.95.

NOISE AND VIBRATION - FIGURE 1

Hydrogen Energy California - Noise Contours at Project Site



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SOURCE: AFC Figure 5.5-4

PUBLIC HEALTH

Alvin Greenberg, Ph.D.

SUMMARY OF CONCLUSIONS

Staff has analyzed potential public health risks associated with construction and operation of the Hydrogen Energy California (HECA) project and does not expect a significant risk of cancer or any adverse short- or long-term noncancer health effects from project toxic emissions. Staff's analysis of potential health impacts from the proposed HECA project was based on a conservative health protective methodology that accounts for impacts to the most sensitive individuals in a given population, including newborns and infants. According to the results of both the applicant's and staff's health risk assessments, emissions of TACs (Toxic Air Contaminants) -- under both the construction periods and routine long-term operations -- from the HECA facility as proposed by the applicant would not contribute significantly to morbidity or mortality in any age or ethnic group residing in the project area. Staff has also considered the potential for adverse air quality impacts to the minority population surrounding the site. With the adoption of the recommended conditions of certification, the project's direct and cumulative air quality impacts would be reduced to less than significant. Therefore, the project will not result in a significant or adverse impact to an identified environmental justice population.

Staff wishes to note that the proposed HECA project is a complex industrial facility similar in scope to a small refinery. The presence of numerous chemical processes -- specifically the larger gasification process and sulfur recovery process that will require the use of large amounts of hazardous materials in closed tanks and piping at elevated temperature and pressure -- pose significant risks of fugitive emissions and accidental releases of toxic air contaminants if not managed properly. Staff has not encountered such a complex power generation facility in the history of the Energy Commission. In order to properly review the expected – and unexpected – emissions from this project, staff spent considerable time evaluating the entire process and even visited a similar gasification facility in Polk County, Florida. As a result of staff's efforts to understand the process and the risks involved, staff determined that in order to keep source, fugitive, and accidental emissions to a level that would not present a significant risk to public health, several processes must be managed in greater detail than usual, regardless of whether the quantities of hazardous materials present would be below the federal or state thresholds that would trigger a need for this increased level of management. Please refer to the analysis in the **Hazardous Materials Management** section of this PSA for further details.

Staff notes that a similar facility precisely the same as the proposed facility has never been built and operated before in any location in the United States. Thus, the routine and fugitive emissions of TACs (Hazardous Air Pollutants or HAPs in U.S. EPA terms) are necessarily based upon measured emissions at similar – but not exactly the same - facilities. Additionally, the applicant and staff were not able to quantitatively describe and assess the short-term fluctuations of emissions of TACs under start-up, commissioning, or upset operating conditions. Staff notes, however, that short-term fluctuations in TAC emissions are not expected to have long-term (chronic) impacts on public health; only acute (short-term) impacts on public health could be impacted. Yet, the potential for short-term impacts due to start-up or upset conditions will be reduced to below a level of significance by the immediate identification and control of these releases. Modeling and measurements of “indicator” emissions (the criteria pollutants) and other operations by continuous emission monitoring (CEM), on-site measurements of accidental chemical releases, and the monitoring of process efficiency parameters (temperature, feed rates, pressure, flow, etc) will enable the facility to ensure that short-term releases of higher amounts than routine, which will invariably occur, will be kept to a minimum and not result in a significant impact on the nearby public or on-site workers. In order to ensure that long-term routine operating emissions will not, as estimated, pose a significant risk to the off-site public, staff proposes that the testing of certain TACs that pose the greatest potential risk and hazard to the public be required and that a health risk assessment be conducted, as per the requirements and schedule of Conditions of Certification **PUBLIC HEALTH-1** and **2**. If the results of any health risk assessment exceeded the regulatory threshold, the project owner would be required to either refine the risk assessment or reduce emissions for TACs. To protect the public from Legionella bacteria, staff proposes a cooling tower water management plan as specified in Condition of Certification **PUBLIC HEALTH-4**.

Also, as discussed in the **Introduction** section of the PSA, this document analyzes the project’s impacts pursuant to both the National Environmental Policy Act (NEPA) and California Environmental Quality Act (CEQA). The two statutes are similar in their requirements concerning analysis of a project’s impacts. Therefore, unless otherwise noted, staff’s use of, and reference to, CEQA criteria and guidelines also encompasses and satisfies NEPA requirements for this environmental document.

INTRODUCTION

The purpose of this Preliminary Staff Assessment/Draft Environmental Impact Statement (PSA/DEIS) is to determine if emissions of toxic air contaminants (TACs) from the proposed HECA would have the potential to cause significant adverse public health impacts or to violate standards for public health protection. If potentially significant health impacts are identified, staff will evaluate mitigation measures to reduce such impacts to less than significant levels.

California Energy Commission (Energy Commission) staff addresses potential impacts of regulated or criteria air pollutants in the **Air Quality** section of this PSA, and impacts on public and worker health from accidental releases of hazardous materials are examined in the **Hazardous Materials Management** section. Health effects from electromagnetic fields are discussed in the **Transmission Line Safety and Nuisance** section. Pollutants released from the project in wastewater streams to the public sewer system are discussed in the **Soil and Surface Water Resources** section. Plant releases in the form of hazardous and nonhazardous wastes are described in the **Waste Management** section.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Public Health Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	
Clean Air Act section 112 (Title 42, U.S. Code section 7412)	This act requires new sources that emit more than 10 tons per year of any specified Hazardous Air Pollutant (HAP) or more than 25 tons per year of any combination of HAPs to apply Maximum Achievable Control Technology (MACT).
State	
California Health and Safety Code section 25249.5 et seq. (Proposition 65)	These sections establish thresholds of exposure to carcinogenic substances above which Prop 65 exposure warnings are required.
California Health and Safety Code section 41700	This section states that “no person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause injury or damage to business or property.”
California Public Resource Code section 25523(a); Title 20 California Code of Regulations (CCR) section 1752.5, 2300–2309 and Division 2 Chapter 5, Article 1, Appendix B, Part (1); California Clean Air Act, Health and Safety Code section 39650, et seq.	These regulations require a quantitative health risk assessment for new or modified sources, including power plants that emit one or more toxic air contaminants (TACs).
California Health and Safety Code, Sections 44360 to 44366 (Air Toxic Hot Spots Information and Assessment Act)	Establishes acceptable levels for toxic contaminants based on the results of an HRA.
Local	
San Joaquin Valley Air Pollution Control District (SJVAPCD) Rule 2520, Section 2.1	This rule requires Federally Mandated Operating Permits for major sources of air toxics.
SJVAPCD Rule 2550	This rule requires the use of Toxics Best Available Control Technology for major sources of hazardous air pollutants in order to achieve MACT.
SJVAPCD Rule 4102, Section 4.1 and Policy APR 1905	This rule requires the preparation of an HRA and prohibits sources from discharging air toxics that are detrimental to public health.

SETTING

This section describes the environment in the vicinity of the proposed project site from the public health perspective. Characteristics of the natural environment, such as meteorology and terrain, affect the project’s potential for causing impacts on public health. An emissions plume from a facility may affect elevated areas before lower terrain areas due to a reduced opportunity for atmospheric mixing. Also, the types of land use near a site influence the surrounding population distribution and density, which, in turn, affect public exposure to project emissions. Additional factors affecting potential public health impacts include existing air quality, existing public health concerns, and environmental site contamination.

SITE AND VICINITY DESCRIPTION

The project site is located in a rural area that is sparsely populated and primarily dedicated to agricultural uses. Land in the general vicinity of the proposed project is designated for agricultural uses as well as some commercial and residential uses. Sensitive receptors in the project vicinity are shown in Figure 5.6-1 of the AFC. The nearest sensitive receptor is the Tule Elk State Natural Reserve[1], located about 1,700 feet east of the project site. The only other sensitive receptor within a 6-mile radius of the project site is the Elk Hills Elementary School, located approximately 1.3 miles southeast of the site boundary. Nearby residences are located approximately 1,400 feet to the east and 3,300 feet to the southeast of the project site. The unincorporated community of Tupman is about 2 miles southeast of the project site (HECA 2012e, Section 5.6.1, Table 5.6-5).

The location of elevated terrain (above the stack height) is important in assessing potential exposure, as an emission plume may impact high elevations before impacting lower elevations. The topography of the site and the surrounding area is essentially flat, about 288.5 feet above mean sea level. The HRSG exhaust stack height would be 213 feet (HECA 2012e, Figure 2-6). Terrain above stack height begins approximately 2 miles south and southwest of the project site where hills begin to rise (HECA 2012e, Figure 2-7).

METEOROLOGY

Meteorological conditions, including wind speed, wind direction, and atmospheric stability, affect the extent to which pollutants are dispersed into ambient air as well as the direction of pollutant transport. This, in turn, affects the level of public exposure to emitted pollutants and associated health risks. When wind speeds are low and the atmosphere is stable, for example, dispersion is reduced, and localized exposure may be increased.

The project region is characterized by a Mediterranean climate; summers are warm and dry and winters are cool with mild precipitation. The average annual rainfall is six inches and 80 percent of it occurs between November and March. Winds flow predominantly from the northwest and north, but some variations occur during fall and winter (HECA 2012e, Section 5.1.1.1).

Atmospheric stability is a measure related to turbulence, or the ability of the atmosphere to disperse pollutants due to convective air movement. Mixing heights (the height above ground level through which the air is well mixed and in which pollutants can be

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[1] Staff defines sensitive receptors any locations where children or the elderly congregate in large numbers such as schools, day care centers, nursing homes, long-term care facilities, hospitals, parks, and playgrounds. Staff considers this location to be a park.

dispersed) are lower during mornings due to temperature inversions and increase during the warmer afternoons. Staff's **Air Quality** section presents more detailed meteorological data.

EXISTING AIR QUALITY

The proposed site is within the jurisdiction of the San Joaquin Valley Air Pollution Control District (SJVAPCD). By examining average toxic concentration levels from representative air monitoring sites with cancer risk factors specific to each contaminant, lifetime cancer risk can be calculated to provide a background risk level for inhalation of ambient air. For comparison purposes, it should be noted that the overall lifetime cancer risk for the average individual in the United States is about 1 in 3, or 333,000 in 1 million.

The nearest monitoring station that measures PM10 and PM 2.5 is the Bakersfield 5558 California Avenue station located about 20 miles east of the project site. The annual arithmetic mean for PM10 measured at this monitoring station ranged between 53.6 and 32.3 micrograms per cubic meter ($\mu g/m^3$) during the years 2008 to 2010. The annual arithmetic mean for PM2.5 ranged between 21.9 and 14.1 during the same period (HECA 2012e, Section 5.1.1.2 and Tables 5.1-3 - 5.1-4).

The nearest California Air Resources Board (CARB) air toxics monitoring station that actively reports values is located on California Avenue in Bakersfield, approximately 20 miles east of the project site. In 2011, the background cancer risk calculated by CARB for the Bakersfield California Ave monitoring station was 116 in one million (CARB 2012). The pollutants 1,3-butadiene and benzene, emitted primarily from mobile sources, accounted together for almost 40 percent of the total risk. The risk from 1,3-butadiene was about 18 in one million, while the risk from benzene was about 26 in one million. Formaldehyde accounts for about 17 percent of the 2011 average calculated cancer risk based on air toxics monitoring results, with a risk of about 20 in one million. Formaldehyde is emitted directly from vehicles and other combustion sources, such as the proposed facility. Risk due to carbon tetrachloride in air represented a risk of about 24 in one million or 21 percent of the total risk. The risk from hexavalent chromium was about 5 in one million, or ~4 percent of the total risk.

The use of reformulated gasoline, beginning in the second quarter of 1996, as well as other toxics reduction measures, have led to a decrease of ambient levels of toxics and associated cancer risk during the past few years in all areas of the state and the nation. For example, in the San Francisco Bay Area, cancer risk was 342 in 1 million based on 1992 data, 315 in 1 million based on 1994 data, and 303 in 1 million based on 1995 data. In 2002, the most recent year for which data is available, the average inhalation cancer risk decreased to 162 in 1 million (BAAQMD 2004, p. 12).

EXISTING PUBLIC HEALTH CONCERNS

When evaluating a new project, staff sometimes conducts a detailed study and analysis of existing public health issues in the project vicinity. This analysis is prepared in order to identify the current status of respiratory diseases (including asthma and Valley Fever), cancer, and cancer rates in the population located near the proposed project. Assessing existing health concerns in the project area will provide staff with a basis on which to evaluate the significance of any additional health impacts from the proposed HECA project and evaluate any proposed mitigation.

In this case, the applicant has stated that no existing health issues have been reported within a 6-mile radius of the project (HECA 2012e, Section 5.6.1). The average cancer mortality rate in Kern County is 183 per 100,000 people, which is just slightly below the state average. Mortality rates from coronary heart disease in Kern County, however, are nearly 20 percent higher than the California statewide average rate (HECA 2012e, Section 5.6.1). Therefore, given this information and in considering the complexity of the proposed project with multiple sources of multiple pollutants, staff conducted an in-depth analysis of existing health issues in the area of Kern County including asthma, Chronic Obstructive Pulmonary Disease (COPD), Valley Fever, and cancer. This analysis is summarized here and presented in full in **Appendix C** below.

Staff reviewed the available information on the current status of respiratory disease and cancer in Kern County, California with particular attention to the region near the proposed Hydrogen Energy California project. Kern County is ranked one of the lowest of the California counties for overall health outcomes. The city of Bakersfield in Kern County is the most polluted city in the nation for annual and 24-hour particulates in the air (PM2.5) and the third most polluted city for ozone. The asthma mortality rate in Kern County is higher than the rate reported for the State of California in general. Likewise, asthma prevalence in Kern County is higher than the prevalence observed in the State of California. Previously, asthma hospitalization and emergency department visit rates in 2008 were reported to be lower in Kern County than in California but that trend was reversed by data reported for 2009 and 2010. Further, the 2008 data shows that the asthma hospitalization and emergency department visit rates for children and adults under age 64 are less than the target rates recommended by the Healthy People (HP) 2020 objectives. Kern County rates for the elderly, however, exceed the HP 2020 level for asthma hospitalizations by a slight margin and are more than double the HP 2020 level for asthma emergency department visits.

Staff also reviewed the latest information about the recent increase in the incidence of Valley Fever in the San Joaquin Valley and nearby San Luis Obispo County. A February 2013 outbreak of Valley Fever affecting at least 28 workers at a photovoltaic solar plant in eastern San Luis Obispo County, along with an increase in inmates at two San Joaquin Valley prisons coming down with the disease, has sparked renewed interest and concern. (The California Department of Public Health, Cal-OSHA, and San Luis Obispo County are investigating the outbreaks). The Centers for Disease Control and Prevention says the total number of Valley Fever cases nationwide rose by nearly 900 percent from 1998 to 2011. Researchers don't have a good explanation for the dramatic increase even when accounting for growing populations throughout the Southwest, although when soil is dry and it is windy, more spores are likely to become airborne in endemic areas, according to Dr. Gil Chavez, Deputy Director of the Center for Infectious Diseases at the California Department of Public Health. Staff addresses this matter in the section on **Worker Safety and Fire Protection**.

The incidence of adult cancer in Kern County is higher for some cancer sites and lower for others compared to the rates in the State of California. Cancer mortality rates of all cancer sites combined are higher in Kern County than in the State of California. Cancer is the leading cause of death by disease in children in California and the United States, with the most common cancers being leukemia and brain and other central nervous system tumors. Within the past 30 years or so, the incidence of childhood cancer has been rising slightly while the mortality rate is declining. In the 1980s two childhood cancer clusters were identified in Kern County but nothing remarkable has been reported since.

Studies reviewed by staff have shown that Kern County is ranked one of the lowest counties in California for overall health outcomes, with Bakersfield being the most polluted city in the nation for particulates and the third most polluted city in the nation for ozone. The mortality rate for asthmatics in Kern County is higher than the rate in the State of California and the city of Bakersfield was found to have the highest asthma hospitalization and emergency department visit rates of Kern County, with hospitalization of African American asthmatics 2.3 times higher than the rate of hospitalization of whites and 3.6 times greater than the hospitalization rate of Hispanics in Kern County.

Staff has considered this information when assessing the incremental and cumulative risk and hazard posed by emissions from the proposed project and when recommending conditions of certification. Staff found that although the risks and hazard would be less than significant, the existing public health concerns and the level of uncertainty about emissions served as a basis for staff's recommendation of conditions **PUBLIC HEALTH-1, 2,** and **3**.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

The **Public Health** section of this staff assessment discusses toxic emissions to which the public could be exposed during project construction and routine operation. Following the release of toxic contaminants into the air or water, people may come into contact with them through inhalation, dermal contact, or ingestion via contaminated food, soil or water.

Air pollutants for which no ambient air quality standards have been established are called noncriteria pollutants. Unlike criteria pollutants such as ozone, carbon monoxide, sulfur dioxide, or nitrogen dioxide, noncriteria pollutants have no ambient (outdoor) air quality standards that specify levels considered safe for everyone.

Since noncriteria pollutants do not have such standards, a health risk assessment is used to determine if people might be exposed to those types of pollutants at unhealthy levels. The risk assessment consists of the following steps:

- identify the types and amounts of hazardous substances that HECA could emit to the environment;
- estimate worst-case concentrations of project emissions in the environment using dispersion modeling;

- estimate amounts of pollutants that people could be exposed to through inhalation, ingestion, and dermal contact; and
- characterize potential health risks by comparing worst-case exposure to safe standards based on known health effects.

Staff relies upon the expertise of the California Environmental Protection Agency (Cal/EPA) Office of Environmental Health Hazard Assessment (OEHHA) to identify contaminants that are known to the state to cause cancer or other noncancer toxicological endpoints and to calculate the toxicity and cancer potency factors of these contaminants. Staff also relies upon the expertise of the California Air Resources Board and the local air districts to conduct ambient air monitoring of toxic air contaminants and the state Department of Public Health to conduct epidemiological investigations into the impacts of pollutants on communities. It is not within the purview or the expertise of the Energy Commission staff to duplicate the expertise and statutory responsibility of these agencies.

Initially, a screening level risk assessment is performed using simplified assumptions that are intentionally biased toward protection of public health. That is, an analysis is designed that overestimates public health impacts from exposure to project emissions. In reality, it is likely that the actual risks from the proposed facility would be much lower than the risks as estimated by the screening level assessment. The risks for screening purposes are based on examining conditions that would lead to the highest, or worst-case, risks and then using those conditions in the study. Such conditions include:

- using the highest levels of pollutants that could be emitted from the plant;
- assuming weather conditions that would lead to the maximum ambient concentration of pollutants;
- using the type of air quality computer model which predicts the greatest plausible impacts;
- calculating health risks at the location where the pollutant concentrations are estimated to be the highest;
- assuming that an individual's exposure to cancer-causing agents occurs continuously for 70 years; and
- using health-based standards designed to protect the most sensitive members of the population (i.e., the young, elderly, and those with respiratory illnesses).

A screening level risk assessment will, at a minimum, include the potential health effects from inhaling hazardous substances. Some facilities may also emit certain substances that could present a health hazard from noninhalation pathways of exposure (OEHHA 2012, Table E2). When these substances are present in facility emissions, the screening level analysis includes the following additional exposure pathways: soil ingestion, dermal exposure, and mother's milk (OEHHA 2012, p. 1-3).

The risk assessment process addresses three categories of health impacts: acute (short-term) health effects, chronic (long-term) noncancer effects, and cancer risk (also long-term). Acute health effects result from short-term (one-hour) exposure to relatively high concentrations of pollutants. Acute effects are temporary in nature and include symptoms such as irritation of the eyes, skin, and respiratory tract.

Chronic health effects are those that arise as a result of long-term exposure to lower concentrations of pollutants. The exposure period is considered to be approximately from 12 percent to 100 percent of a lifetime, or from 9 to 70 years (OEHHA 2012, p. 1-6). Chronic health effects include diseases such as reduced lung function and heart disease.

The analysis for noncancer health effects compares the maximum project contaminant levels to safe levels called *Reference Exposure Levels*, or RELs. These are amounts of toxic substances to which even sensitive people can be exposed and suffer no adverse health effects (OEHHA 2012). These exposure levels are designed to protect the most sensitive individuals in the population, such as infants, the aged, and people suffering from illness or disease which makes them more sensitive to the effects of toxic substance exposure. The Reference Exposure Levels are based on the most sensitive adverse health effect reported in the medical and toxicological literature and include margins of safety. The margin of safety addresses uncertainties associated with inconclusive scientific and technical information available at the time of standard setting and is meant to provide a reasonable degree of protection against hazards that research has not yet identified. The margin of safety is designed to prevent pollution levels that have been demonstrated to be harmful, as well as to prevent lower pollutant levels that may pose an unacceptable risk of harm, even if the risk is not precisely identified as to nature or degree. Health protection is achieved if the estimated worst-case exposure is below the relevant reference exposure level. In such a case, an adequate margin of safety exists between the predicted exposure and the estimated threshold dose for toxicity.

Exposure to multiple toxic substances may result in health effects that are equal to, less than, or greater than effects resulting from exposure to the individual chemicals. Only a small fraction of the thousands of potential combinations of chemicals have been tested for the health effects of combined exposures. In conformity with the California Air Pollution Control Officers Association (CAPCOA) guidelines, the health risk assessment assumes that the effects of each substance are additive for a given organ system (OEHHA 2012, pp. 1-12). Other possible mechanisms due to multiple exposures include those cases where the actions may be synergistic or antagonistic (where the effects are greater or less than the sum, respectively). For these types of substances, the health risk assessment could underestimate or overestimate the risks.

For carcinogenic substances, the health assessment considers the risk of developing cancer and assumes that continuous exposure to the cancer-causing substance occurs over a 70-year lifetime. The risk that is calculated is not meant to project the actual expected incidence of cancer, but rather a theoretical upper-bound number based on worst-case assumptions.

Cancer risk is expressed in chances per million and is a function of the maximum expected pollutant concentration, the probability that a particular pollutant will cause cancer (called *potency factors* and established by OEHHA), and the length of the exposure period. Cancer risks for each carcinogen are added to yield total cancer risk.

The conservative nature of the screening assumptions used means that actual cancer risks due to project emissions are likely to be considerably lower than those estimated.

The screening analysis is performed to assess worst-case risks to public health associated with the proposed project. If the screening analysis predicts no significant risks, then no further analysis is required. However, if risks are above the significance level, then further analysis, using more realistic site-specific assumptions, would be performed to obtain a more accurate assessment of potential public health risks.

Significance Criteria

Energy Commission staff determines the health effects of exposure to toxic emissions based on impacts to the maximum exposed individual. This is a person hypothetically exposed to project emissions at a location where the highest ambient impacts were calculated using worst-case assumptions, as described above.

As described earlier, noncriteria pollutants are evaluated for short-term (acute) and long-term (chronic) noncancer health effects, as well as cancer (long-term) health effects. The significance of project health impacts is determined separately for each of the three categories.

Acute and Chronic Noncancer Health Effects

Staff assesses the significance of noncancer health effects by calculating a *hazard index*. A hazard index is a ratio comparing exposure from facility emissions to the reference (safe) exposure level. A ratio of less than 1.0 signifies that the worst-case exposure is below the safe level. The hazard index for every toxic substance that has the same type of health effect is added to yield a Total Hazard Index. The Total Hazard Index is calculated separately for acute and chronic effects. A Total Hazard Index of less than 1.0 indicates that cumulative worst-case exposures are less than the reference exposure levels. Under these conditions, health protection from the project is likely to be achieved, even for sensitive members of the population. In such a case, staff presumes that there would be no significant noncancer project-related public health impacts.

Cancer Risk

Staff relied upon regulations implementing the provisions of Proposition 65, the Safe Drinking Water and Toxic Enforcement Act of 1986, (Health & Safety Code, §§25249.5 et seq.) for guidance to determine a cancer risk significance level. Title 22, California Code of Regulations section 12703(b) states that “the risk level which represents no significant risk shall be one which is calculated to result in one excess case of cancer in an exposed population of 100,000, assuming lifetime exposure.” This level of risk is equivalent to a cancer risk of 10 in 1 million, which is also written as 10×10^{-6}. An important distinction is that the Proposition 65 significance level applies separately to each cancer-causing substance, whereas staff determines significance based on the cumulative total risk from all cancer-causing chemicals. Thus, the manner in which the significance level is applied by staff is more conservative (health-protective) than that applied by Proposition 65. The significant risk level of 10 in 1 million is consistent with the level of significance adopted by many air districts. In general, these air districts would not approve a project with a cancer risk exceeding 10 in 1 million. The SJVAPCD also uses 10 in 1 million as the level of “Significant Health Risk” (SJVAPCD 2006).

As noted earlier, the initial risk analysis for a project is typically performed at a screening level, which is designed to overstate actual risks, so that health protection can be ensured. Staff’s analysis also addresses potential impacts on all members of the population including the young, the elderly, people with existing medical conditions that may make them more sensitive to the adverse effects of toxic air contaminants, and any minority or low-income populations that are likely to be disproportionately affected by impacts. To accomplish this goal, staff uses the most current acceptable public health exposure levels (both acute and chronic) set to protect the public from the effects of airborne toxics. When a screening analysis shows cancer risks to be above the significance level, refined assumptions would likely result in a lower, more realistic risk estimate. Based on refined assumptions, if risk posed by the facility exceeds the significance level of 10 in 1 million, staff would require appropriate measures to reduce the risk to less than significant. If, after all risk reduction measures have been considered, a refined analysis identifies a cancer risk greater than 10 in 1 million, staff would deem such risk to be significant and would not recommend project approval.

DIRECT/INDIRECT IMPACTS AND MITIGATION

CONSTRUCTION IMPACTS AND MITIGATION

Potential risks to public health during construction may be associated with exposure to toxic substances in contaminated soil disturbed during site preparation, as well as diesel exhaust from heavy equipment operation. Criteria pollutant impacts from the operation of heavy equipment and particulate matter from earth moving are examined in staff’s **Air Quality** analysis.

Site disturbances occur during facility construction from excavation, grading, and earth moving. Such activities have the potential to adversely affect public health through various mechanisms, such as the creation of airborne dust, material being carried off site through soil erosion, and uncovering buried hazardous substances. The Phase I Environmental Site Assessment conducted for this site in 2009 found several environmental conditions that may have potentially impacted the soil at the project site. Most of the potential contamination at the site is due to underground storage tanks and the historical use of the site for fertilizer manufacturing. The Phase I ESA identified two RECs (Recognized Environmental Conditions) for the project: elevated concentrations of petroleum hydrocarbons and other contaminants found immediately north of the property and stained soils observed during the property visit. Two potential environmental issues were also noted in the ESA: sampling of surficial soils showed the presence of low concentrations of pesticides, consistent with the historical agricultural use at the site, and the possibility that five former underground storage tanks (USTs) may have historically been located on or adjacent to the site according to an agency database (HECA 2012e, Appendix L).

In the event that any contamination is encountered during construction, proposed Conditions of Certification **WASTE-1** and **WASTE-2** (which require a registered professional engineer or geologist to be available during soil excavation and grading to ensure proper handling and disposal of contaminated soil) would ensure that contaminated soil does not affect the public. See the staff assessment section on **Waste Management** for a more detailed analysis of this topic.

The operation of construction equipment would result in air emissions from diesel-fueled engines. Diesel emissions are generated from sources such as trucks, graders, cranes, welding machines, electric generators, air compressors, and water pumps. Although diesel exhaust contains criteria pollutants such as nitrogen oxides, carbon monoxide, and sulfur oxides, it also includes a complex mixture of thousands of gases and fine particles. These particles are primarily composed of aggregates of spherical carbon particles coated with organic and inorganic substances. Diesel exhaust contains over 40 substances that are listed by the U.S. Environmental Protection Agency (U.S. EPA) as hazardous air pollutants and by the California Air Resources Board (ARB) as toxic air contaminants.

Exposure to diesel exhaust may cause both short- and long-term adverse health effects. Short-term effects can include increased coughing, labored breathing, chest tightness, wheezing, and eye and nasal irritation. Long-term effects can include increased coughing, chronic bronchitis, reductions in lung function, and inflammation of the lung. Epidemiological studies also strongly suggest a causal relationship between occupational diesel exhaust exposure and lung cancer.

Based on a number of health effects studies, the Air Resources Board’s Scientific Review Panel on Toxic Air Contaminants recommended a chronic reference exposure level (see discussion of reference exposure levels in Method of Analysis section above) for diesel exhaust particulate matter of 5 micrograms of diesel particulate matter per cubic meter of air ($\mu g/m^3$) and a cancer unit risk factor of $3x10^{-4}$ $(\mu g/m^3)^{-1}$ (SRP 1998, p. 6). The Scientific Review Panel did not recommend a value for an acute Reference Exposure Level since available data in support of a value was deemed insufficient. On August 27, 1998, ARB listed particulate emissions from diesel-fueled engines as a toxic air contaminant and approved the panel’s recommendations regarding health effect levels.

Construction of the HECA project is anticipated to take place over a period of 42 months. Appendix E of the Amended AFC presents monthly and annual maximum construction emissions from construction equipment diesel exhaust. The applicant conducted a health risk assessment for diesel particulate matter from construction activities using the annual emissions associated with the peak construction period to estimate PM10 concentrations and adjusted the exposure period to reflect the 4.1-year duration. As noted earlier, assessment of chronic (long-term) health effects assumes continuous exposure to toxic substances over a significantly longer time period, typically from 9 to 70 years. The applicant’s HRA calculations resulted in a cancer risk of 5.5 in 1,000,000 and a chronic hazard index of 0.046 at the point of maximum impact, both below the level of significance. Health risks calculated at the locations of the nearest worker, nearest residence, and nearest sensitive receptor were all significantly lower (HECA 2012e, Table 5.6-4).

Mitigation measures are proposed by both the applicant and Energy Commission staff to reduce the maximum calculated PM10 emissions. These include the use of extensive fugitive dust control measures. The fugitive dust control measures are assumed to result in 90 percent reductions of emissions. In order to further mitigate potential impacts from particulate emissions during the operation of diesel-powered construction equipment, the use of ultra-low sulfur diesel fuel and the highest Tier level available from the California Emission Standards for Off-Road Compression-Ignition Engines requirements or installation of an oxidation catalyst and soot filters on diesel equipment are required to bring Lower Tiered engines up to emissions equivalent to current Off Road engine requirements. The catalyzed diesel particulate filters are passive, self-regenerating filters that reduce particulate matter, carbon monoxide, and hydrocarbon emissions through catalytic oxidation and filtration. The degree of particulate matter reduction is comparable for both mitigation measures in the range of approximately 85–92 percent. Such filters will reduce diesel emissions during construction and reduce any potential for significant health impacts.

Valley Fever

Coccidioidomycosis or "Valley Fever" (VF) is a disease caused by inhaling spores of the fungus Coccidioides immitis, which is present in the soil of the San Joaquin Valley and other regions of Southern California and Arizona. Kern County, located at the southern end of San Joaquin valley, is where Valley Fever occurs most frequently. The disease usually affects the lungs and can have potentially severe consequences, especially in at-risk individuals such as the elderly, pregnant women, and people with compromised immune systems. Staff has addressed this issue in-depth for onsite workers in the **Worker Safety and Fire Protection** section of this PSA/DEIS. Staff believes that the persons who would have the greatest exposure and thus who would be most at risk are the workers involved in soil disturbance activities or those on the site when soil is moved during grading and excavation. Staff contends that if the workers are protected to the greatest extent possible from contracting Valley Fever, then the off-site public would also be protected. Furthermore, in the Air Quality section, staff proposes several mitigation measures intended to keep fugitive dust emissions from leaving the project site.

OPERATION IMPACTS AND MITIGATION

Emissions Sources

The emissions sources at the proposed HECA are many and include the HRSG combustion turbine, power block cooling towers, gasifier refractory heaters, auxiliary boiler, gasification flare, SRU flare, rectisol flare, tail gas thermal oxidizer, carbon dioxide vent, diesel emergency generator, a diesel fire pump engine, rail delivery and/or heavy truck traffic associated with petcoke, coal, and gasifier solids handling, and fugitive emissions from various plant components (HECA 2012e, Section 5.1.2.3). As noted earlier, the first step in a health risk assessment is to identify potentially toxic compounds that may be emitted from these sources.

Appendix M of the Amended AFC (HECA 2012e, Appendix M), on page 1 of 26, lists noncriteria pollutants that may be emitted from all sources at HECA, along with their anticipated amounts (emission factors). Subsequent to the submittal of the Amended Application for Certification (AFC), revised emission factors were provided by the applicant in January 2013, in documents titled: "Appendix M Public Health 2012-12-28" and "Emission Source Modification List." Emissions from some sources were changed due to project refinements and in response to data requests. These revised emission factors were used in this assessment.

Toxic Air Contaminant emission factors were obtained from the Environmental Protection Agency (EPA) AP-42 database of emission factors and from other sources as noted in the respective table for each project component. Appendix M also provides estimates of fugitive emissions from various plant components such as methanol, propylene, acid gas, and ammonia-laden gas from pumps, valves, and connectors. The applicant will implement a leak detection and repair (LDAR) program to identify and repair leaking equipment and thereby reduce fugitive emissions. The applicant's HRA included total TAC emissions estimated for all sources listed above (including fugitive emissions) as listed on page 1 of 26 in Appendix M Public Health 20121228 (confidential filing).

During the environmental review of the original project in 2008, staff requested that the then-applicant identify and quantify any radioisotopes potentially released from pet coke and coal during gasification. The applicant at that time responded that based on information provided in a National Institute of Occupational Safety and Health (NIOSH) document, coal is typically radioactive to the same extent as sedimentary rock. That is, coal is expected to have only trace amounts of radioisotopes and no significant radiological exposure is expected from coal gasification (URS 2010b, Data Response 150).

Table 5.6-2 of the Amended AFC (2012) lists toxicity values used to characterize cancer and noncancer health impacts from project pollutants. The toxicity values include Reference Exposure Levels, which are used to calculate short-term and long-term noncancer health effects, and cancer unit risks, which are used to calculate the lifetime risk of developing cancer, as published in the OEHHA Guidelines (OEHHA 2012). **Public Health Table 2** lists 36 toxic emissions which would be potentially emitted from 294 sources within the HECA facility and shows how each contributes to the health risk analysis.

Public Health Table 2
Health Impacts and Exposure Routes Attributed to Toxic Emissions from the Proposed Facility

Substance	Oral Cancer	Oral Noncancer	Inhalation Cancer	Noncancer (Chronic)	Noncancer (Acute)
3-Methylcholanthrene	✔		✔		
7,12- Dimethyl benz(a)anthracene	✔		✔		
Acetaldehyde			✔	✔	✔
Ammonia				✔	✔
Arsenic	✔	✔	✔	✔	✔
Benzene			✔	✔	✔

Substance	Oral Cancer	Oral Noncancer	Inhalation Cancer	Noncancer (Chronic)	Noncancer (Acute)
Beryllium		✔	✔	✔	
Cadmium		✔	✔	✔	
Carbon Disulfide				✔	✔
Chromium (VI)		✔	✔	✔	
Copper					✔
Cyanides				✔	✔
Dichlorobenzene			✔	✔	
Diesel Particulate			✔	✔	
Fluoride		✔		✔	✔
Formaldehyde			✔	✔	✔
Hexane				✔	
HCl				✔	✔
Hydrogen Fluoride		✔		✔	✔
Hydrogen Sulfide				✔	✔
Lead	✔		✔		
Manganese				✔	
Mercury		✔		✔	✔
Methanol				✔	✔
Methyl Bromide				✔	✔
Methylene Chloride			✔	✔	✔
Naphthalene			✔	✔	
Nickel		✔	✔	✔	✔
Nitric Acid					✔
Phenol				✔	✔
PAHs	✔	✔	✔		
Propylene				✔	
Selenium				✔	
Sulfuric Acid and Sulfates				✔	✔
Toluene				✔	✔
Vanadium					✔

Source: OEHHA 2012, Appendix E and HECA 2012e, Table 5.6-2.

Emissions Levels

Once potential emissions are identified, the next step is to quantify them by conducting a “worst case” analysis. Maximum hourly emissions are required to calculate acute (one-hour) noncancer health effects, while estimates of maximum emissions on an annual basis are required to calculate cancer and chronic (long-term) noncancer health effects.

The next step in the health risk assessment process is to estimate the ambient concentrations of toxic substances. This is accomplished by using a screening air dispersion model and assuming conditions that result in maximum impacts. The applicant's screening analysis was performed using the ARB/OEHHA Hotspots Analysis and Reporting Program (HARP). Ambient concentrations were used in conjunction with Reference Exposure Levels and cancer unit risk factors to estimate health effects that might occur from exposure to facility emissions. Exposure pathways, or ways in which people might come into contact with toxic substances, include inhalation, dermal (through the skin) absorption, soil ingestion, consumption of locally grown plant foods, and mother's milk. As an ancillary issue, staff is aware of the concerns expressed by neighbors in the area that persons consuming crops grown in the area, specifically pistachios, might be adversely impacted. While staff did not conduct a risk assessment to determine the precise risk posed to people consuming pistachios, the results of staff's human health risk assessment show that the ground level concentrations of TACs over the area and any uptake into crops in general would be very low and would not result in a significant risk to public health. It is highly likely that the consumption of pistachios would be included in this finding and not pose a significant risk.

The above method of assessing health effects is consistent with OEHHA's Air Toxics Hot Spots Program Risk Assessment Guidelines (OEHHA 2012) referred to earlier and results in the following health risk estimates.

Impacts

The applicant's screening health risk assessment for the project including emissions from all sources as presented in the Amended AFC (HECA 2012e, Section 5.6.2.7 and Table 5.6-5) resulted in a maximum acute Hazard Index (HI) of 0.88 and a maximum chronic HI of 0.42 at the point of maximum impact (PMI). The total worst-case individual cancer risk was calculated by the applicant to be 8.97 in 1 million at the PMI. Calculated health risks at the location of the maximum exposed worker, maximum exposed residence, and nearest sensitive receptor were all significantly lower (HECA 2012e, Table 5.6-5). As **Public Health Table 3** shows, both acute and chronic hazard indices are less than 1.0, and cancer risk is less than 10 in 1 million, indicating that no short- or long-term adverse health effects are expected.

Public Health Table 3
Operation Hazard/Risk at Point of Maximum Impact: Applicant Assessment

Type of Hazard/Risk	Hazard Index/Risk	Significance Level	Significant?
Acute Noncancer	0.88	1.0	No
Chronic Noncancer	0.42	1.0	No
Individual Cancer	8.97 in a million	10.0 in a million	No

Source HECA 2012e, Table 5.6-5

Staff conducted a quantitative evaluation of the risk assessment results presented in the Hydrogen Energy California (HECA) Amended AFC (08-AFC-8A). Modeling files provided by the applicant, dated May, August and November 2012, were also evaluated. Emission factors from the Emission Source Modification List were used in this analysis.

The risk assessment appears to be complete, transparent, and the results were verified in staff's analysis. This health risk assessment can be used to support staff's opinion that the proposed project will not result in a significant risk to public health.

Staff has determined that the most significant emission source of the proposed project is the CTG/HRSG train. According to Section 5.6.2.3 of the Amended AFC, emission rates of toxic air contaminants (TACs) from the CTG were determined based on firing of hydrogen-rich fuel under operating conditions determined in Section 5.1, Air Quality, to result in the highest off-site ground-level impacts. It should be noted that Section 5.6.2.3 indicates that emission rates are taken from "Wabash River test data and the National Energy Technology Laboratory, U.S. Dept of Energy, Major Environmental Aspects of Gasification-based Power Generation Technologies, Final Report, December 2002." Staff is not familiar with this facility but queried the applicant about the comparability of the processes and TAC emissions and staff is satisfied that a report prepared by the US Dept. of Energy could serve as the basis for emission factors. Staff has no evidence to refute the validity and appropriateness of this data.

Construction Phase Analysis

For the construction phase analysis, atmospheric dispersion modeling of diesel particulate matter (DPM) emissions from construction equipment and vehicles was conducted by the applicant using AERMOD. The maximum predicted offsite concentration of diesel particulate matter, on a 70-year basis, was reported by the applicant to be 0.228 ug/m^3 (HECA 2012e, Table 5.6-4). Cancer risk and chronic hazard index values obtained by staff are compared to results reported by the applicant in the January 2010 modeling files in **Public Health Table 4**. Cancer risk due to diesel exhaust emissions was determined by multiplying the DPM concentration by the diesel cancer inhalation unit risk of 0.0003 (ug/m^3)$^{-1}$ and adjusting by the estimated construction period of 4.1 years over a 70 year lifetime for residential receptors. The difference between the applicant's assessment and staff's are minor and can be attributed to using slightly different input values. All results are below the level of significance.

Public Health Table 4
Results of Staff's Analysis and the Applicant's Analysis for Cancer Risk and Chronic Hazard during Construction Phase

		Staff's Analysis		Applicant's Analysis	
	Annual PM10 Concentration (ug/m^3)	Cancer Risk (per million)	Chronic HI	Cancer Risk (per million)	Chronic HI
PMI	0.228	4.0	0.046	5.5	0.046
MEIW	0.0244	0.43	0.0049	0.16	0.0049

		Staff's Analysis		Applicant's Analysis	
	Annual PM10 Concentration (ug/m^3)	Cancer Risk (per million)	Chronic HI	Cancer Risk (per million)	Chronic HI
MEIR-1	0.0499	0.88	0.010	1.21	0.010
Nearest school	0.0051	0.089	0.002	0.12	0.001

Note:
PMI = point of maximum impact (or maximally impacted receptor, MIR); the PMI for cancer risk and chronic hazard index is located southeast of the property, Receptor #135 (UTM coordinates 283960E, 3911650N)
MEIW = maximally exposed individual, worker is located east of the property at the Tule Elk State Reserve Ranger Station, Receptor #5495 (UTM coordinates 285170E, 3912389N); evaluated under the worker exposure scenario (10 hours/day, 250 days/year, 35 years)
MEIR-1 = maximally exposed individual, residential is located at the northwest corner of the property, Receptor #5496 (UTM coordinates 282408E, 3913181N)
Nearest school = located at Elk Hills School in Tupman, Rec #5494 (UTM coordinates 285878E, 3908605N)

Operations Phase Analysis

For the operations phase analysis, atmospheric dispersion modeling of facility emissions was conducted by the applicant using AERMOD. Local meteorological data were used, building downwash effects were included for 61 buildings, and 5,047 receptors were modeled.

The 294 emitting units modeled by the applicant include:

Routine Emissions:

- 1 Combustion turbine generator with associated heat steam generator (CTG/HRSG)
- 1 Coal dryer
- 1 Tail gas thermal oxidizer (TGTO) stack
- 1 Auxiliary boiler
- 1 CO_2 vent
- 2 Emergency diesel generators
- 1 Emergency firewater pump diesel engine
- 1 Ammonia heater
- 1 Urea pastillation stack
- 2 Urea plant absorbers
- 1 Nitric acid plant stack
- 4 ASU (air separation unit) cooling tower stacks
- 12 Power block cooling tower stacks
- 13 Process cooling tower stacks

Flares:

- 1 Rectisol flare
- 1 Gasification flare
- 1 SRU (sulfur recovery unit) flare

Transportation:

- 2 Idling incoming coal/coke delivery trucks
- 7 Idling product trucks
- 73 Product trucks
- 34 Coal/coke delivery trucks
- 5 Miscellaneous HHDT diesel trucks
- 10 Onsite diesel operations and maintenance trucks
- 104 Rail

Fugitives:

- 3 Gasification area fugitives
- 2 Shift area fugitives (Shift)
- 1 AGR (acid gas removal) fugitives
- 2 SRU (sulfur recovery unit) fugitives
- 1 UAN fugitives
- 2 Ammonia unit fugitives
- 2 Urea unit fugitives
- 1 SWS (sour water stripper) fugitives

Feedstocks expected to be used in the proposed facility include petroleum coke, western bituminous coal, and natural gas. The modified emission factors provided in January 2013 were used in this analysis and are listed in **Public Health Tables 5** and **6** below.

Staff conducted independent AERMOD modeling and a limited focused risk analysis for the eight specific stationary sources and six receptors listed below. Staff conducted a limited assessment due to the complexity of the facility, the number of TACs, the high number of emission sources, and the complexity of combining stationary source and the high number of mobile sources. Staff's analysis serves as a "spot check" on the applicant's analysis and assesses the TACs that, in staff's opinion, would contribute the most to public health impacts.

Emissions Sources: HRSG, Coal Dryer, CO_2 Vent, Gasification fugitives, Shift area fugitives, AGR fugitives, SRU fugitives, SWS fugitives.

Receptors:

- Point of maximum impact (PMI) for cancer risk, located towards the southeast corner of the proposed project at Tupman Road
- PMI for noncancer chronic hazard, located towards the southeast corner of the proposed project at Tupman Road (close to the cancer PMI)
- PMI for noncancer acute hazard, located northwest of the proposed project

- Maximally exposed individual receptor (MEIR) for cancer risk and noncancer hazard, located at a residence along the southeastern side of the property line on Tupman Road
- MEIR for acute hazard, located at a residence on Tule Park Road near Station Road
- Nearest sensitive receptor, Elk Hills School in Tupman

Air dispersion modeling was conducted by air quality staff using AERMOD with default regulatory settings over five years of meteorological data. The air dispersion modeling results provided ground level airborne concentrations of contaminants normalized to a unit value emission rate (expressed as Chi/Q values (in units of ug/m^3 per g/sec) for each source at each receptor (see **Public Health Table 7**). These values were used with the emission factors listed in **Public Health Tables 5** and **6** (converted to units of g/sec) to determine average annual and 1-hour ground level concentrations of each emitted substance at each receptor. These values were then used in a human health risk assessment (using the most current Cal-EPA OEHHA guidelines published in August 2012) to estimate cancer risk and noncancer hazard at each receptor for emissions from the eight sources evaluated and results are listed in **Public Health Tables 8** and **9**. Only the substances that are emitted from the sources evaluated by staff are included in the tables that accompany this analysis. Modified emission factors were not provided in the Emission Source Modification List (January 2013) for four of the fugitive sources (Shift, AGR, SRU and SWS; see above for definitions). Emissions from these fugitives were combined and presented as a single value whereas fugitive emissions were delineated by source in the Amended AFC. In staff's analysis, the proportionate contribution of each of the four fugitive sources to the total amount of each substance emitted in the Amended AFC was applied to the combined fugitive emissions amount presented in the Emission Source Modification List to estimate the modified emissions from the Shift, AGR, SRU and SWS fugitive sources.

A health risk assessment (HRA) evaluates exposure due to all complete exposure pathways (the exposure assessment component of a HRA), followed by the dose-response assessment component in which dose is quantified, and then cancer risk and noncancer health impacts are assessed in the risk characterization component of the HRA (OEHHA 2012). The most recent exposure methodology developed by Cal-EPA OEHHA and recommended for human health risk assessment was used in this assessment (OEHHA August 2012).

Off-site residents are assumed to be potentially exposed to airborne emissions from the proposed facility as well as emitted particulates that are deposited off-site through the following exposure pathways:

- Inhalation
- Ingestion of soil upon which chemical-containing particulates from the project have been deposited
- Dermal contact with soil upon which chemical-containing particulates from the project have been deposited

This assessment assumes that 100 percent of the soils ingested and 100 percent of the soil available for dermal contact would be impacted by chemical-containing particulates from the project. Although these exposure assumptions are physically impossible – soils carried off-site would undoubtedly mix with existing off-site soils and thus be diluted to some extent - they are used in this assessment to ensure that “conservative health protective” methods are used to calculate the theoretical upper-bound risk and hazard levels, thus also ensuring that the true risks are not underestimated. Also, additivity of risk is assumed throughout this assessment, a health protective method that is required by both Cal EPA and U.S. EPA guidelines.

Exposure parameters and toxicity values are presented in **Public Health Tables 10** and **11**, respectively. Algorithms used in the exposure and risk analysis are presented in **Public Health Appendix A**.

Cancer risk and chronic and acute hazard index values obtained by staff are compared to results reported by the applicant in the May 2012 modeling files in **Public Health Table 12**. Risk and hazard were determined at the point of maximum impact (PMI) for cancer risk, chronic noncancer hazard and acute hazard. Additionally, risk and hazard were determined at the location of the maximally exposed individual resident (MEIR) and at the nearest sensitive receptor, Elk Hills School in Tupman. The analyses for each receptor are included as tables in Appendix B.

The inhalation pathway contributes 43 percent of risk to the total cancer risk estimated by staff for the cancer PMI (Public Health Table B.1-2). Soil ingestion accounts for 54 percent of total risk and dermal contact is 3.5 percent. **Public Health Table 13** presents the contribution to total risk and hazard by individual substances that are emitted from the eight sources that were evaluated in staff’s analysis. Analysis of this table indicates that 62 percent of the cancer risk at the PMI is attributed to arsenic, 24 percent to cadmium, and 13 percent to hexavalent chromium. For chronic hazard, 89 percent is attributed to arsenic with cadmium and manganese at 4 percent and 5 percent, respectively. For acute hazard, the majority of the hazard index is due to hydrogen sulfide (78 percent) and carbonyl sulfide (18 percent). Note that the applicant did not include carbonyl sulfide in its health risk assessment because there are no toxicity values (RfCs or RELs) available to calculate risk or hazard. However, the applicant did provide an emission factor and Cal-EPA and US EPA both state that it is proper risk assessment procedure to use toxicity values of a “surrogate” similar chemical that has toxicity values available for use. Thus, staff included carbonyl sulfide in its HRA by assuming it to have the same toxicity as hydrogen sulfide. Hydrogen sulfide is not carcinogenic and staff has seen no evidence that carbonyl sulfide would be carcinogenic and thus only a non-hazard Hazard Index was calculated for carbonyl sulfide.

A review of staff’s analysis shown in **Public Health Table 12** raises a question about the levels of the Hazard Indices for non-cancer acute and chronic impacts. Both values (0.95 and 0.97 at the location (point) of the chronic maximum impact; PMIc) are very close to the value of 1.0, a level that does not necessarily mean that adverse impacts are expected but rather that further analysis and refinement of the exposure assessment is warranted. Staff, however, believes that based on assessment of the top TACs in toxicity and contribution to potential public health impacts, combined with the results shown in **Public Health Table 13**, if all the remainder TACs were added to the assessment, no significant incremental increase in the Hazard Index would occur. That is, the percent contributions to the HI from all other TACs would be far less than 1 percent and thus the HI might increase from 0.97 in tenths or hundredths of a percent increments.

The differences seen in **Public Health Table 12** between the applicant's results and staff's results are due to several differences in approach. First, staff conducted a focused limited assessment of the stationary sources and TACs it believed would contribute the most to risk or hazard. Mobile (train and truck) sources were not included in staff's assessment. The applicant's assessment included all stationary and mobile sources and thus the cancer risk predicted by the applicant was greater (8.97 in one million at the PMI) than that predicted by staff (3.1 in one million at the PMI). Staff's use of a more sophisticated and recent risk assessment methodology, slight differences in air dispersion modeling inputs, and the inclusion of carbonyl sulfide in staff's assessment also contributed to the differences found for chronic hazard (staff: 0.97; applicant: 0.42) and acute hazard (staff:0.96; applicant: 0.88). However, although values derived by staff differ from those of the applicant, all are below respective significance levels.

An area of uncertainty also exists in the emissions and hence risk/hazard posed by the use of groundwater in the cooling towers. The identity and concentration of chemicals in the groundwater can change and a survey of other wells in the area (internal staff investigation) shows that in addition to the chemicals found in the groundwater proposed to be used for cooling and thus included in the applicant's and staff's risk assessment (see **Public Health Table 5**), chromium+6, mercury, magnesium, and zinc have been found. If these chemicals ultimately prove to be present in the groundwater used for cooling at the HECA facility, the risk/hazard from cooling tower emissions could be higher than both staff and applicant have calculated. However, because the contribution to risk/hazard due to cooling tower emissions has been found by staff to be low at all power plant sites assessed by staff in the past, it is extremely doubtful that even if these additional contaminants were present (with the exception of hexavalent chromium due to its very high cancer potency via the inhalation route of exposure), the risk/hazard would not be significantly greater than already estimated.

Public Health Table 5
Operation Phase Annual Emission Rates (lb/yr)

Substance	CTG/HRSG	Coal Dryer	ASU Cooling Tower (each of 4 units)	Power Block Cooling Tower (each of 12 units)	Process Cooling Tower (each of 13 units)
Annual Emissions (lb/yr)					
Acetaldehyde	3.62E+01	6.38E+00			
Antimony	2.21E+01	3.90E+00			
Arsenic	4.82E+01	8.51E+00	2.40E-02	5.33E-02	8.70E-02
B[a]anthracene	4.62E-02	8.16E-03			
Benzene	4.82E+01	8.51E+00			
Beryllium	5.22E+00	9.22E-01			

Substance	CTG/HRSG	Coal Dryer	ASU Cooling Tower (each of 4 units)	Power Block Cooling Tower (each of 12 units)	Process Cooling Tower (each of 13 units)
Annual Emissions (lb/yr)					
Cadmium	1.93E+02	3.40E+01			
Chromium	1.02E+01	1.81E+00			
Cobalt	5.22E+00	9.22E-01			
Copper			4.66E-03	1.03E-02	1.69E-02
Cr(VI)	3.07E+00	5.43E-01			
CS2	9.24E+02	1.63E+02			
Cyanide cmpds	1.15E+02	2.02E+01			
Fluorides & cmpds			4.20E-01	9.31E-01	1.52E+00
Formaldehyde	3.42E+02	6.03E+01			
HCl	2.61E+02	4.61E+01			
HF	1.00E+03	1.77E+02			
Lead	1.13E+01	1.99E+00			
Manganese	2.09E+01	3.69E+00	1.20E+00	2.66E+00	4.35E+00
Mercury	4.09E+00	4.18E+00			
Methyl Bromide	9.59E+02	1.69E+02			
Methylene Chloride	4.42E+01	7.80E+00			
Naphthalene	5.02E+01	8.87E+00			
NH3	1.54E+05	2.72E+04			
Nickel	7.84E+00	1.38E+00			
Phenol	7.40E+02	1.31E+02			
Selenium	1.13E+01	1.99E+00	2.00E-02	4.43E-02	7.23E-02
Sulfuric Acid	1.91E+03	3.37E+02			
Toluene	6.63E-01	1.17E-01			

Source: Applicant's Emission Source Modification List, Jan. 2013
Values are expressed in scientific notation where 1E+01 = 10, 1E+2 = 100, etc.

Public Health Table 5 (continued)
Operation Phase Annual Emission Rates (lb/yr)

Substance	Auxiliary Boiler	Tail Gas Thermal Oxidizer	Ammonia Heater	CO2 Vent
Annual Emissions (lb/yr)				
2MeNaphthalene	1.07E-02	2.56E-03	1.76E-04	
3-MeCholanthren	8.00E-04	1.92E-04	1.32E-05	
7,12-DB[a]anthr	7.11E-03	1.71E-03	1.17E-04	
Acenaphthene	8.00E-04	1.92E-04	1.32E-05	
Acenaphthylene	8.00E-04	1.92E-04	1.32E-05	
Anthracene	1.07E-03	2.56E-04	1.76E-05	
Arsenic	8.89E-02	2.13E-02	1.47E-03	
B[a]anthracene	8.00E-04	1.92E-04	1.32E-05	
B[a]P	5.33E-04	1.28E-04	8.80E-06	
B[b]fluoranthen	8.00E-04	1.92E-04	1.32E-05	
B[g,h,i]perylen	5.33E-04	1.28E-04	8.80E-06	
B[k]fluoranthen	8.00E-04	1.92E-04	1.32E-05	
Benzene	9.33E-01	2.24E-01	1.54E-02	
Beryllium	5.33E-03	1.28E-03	8.80E-05	
Cadmium	4.89E-01	1.17E-01	8.07E-03	
Carbonyl sulfide				5.32E+03
Chromium	6.22E-01	1.49E-01	1.03E-02	
Chrysene	8.00E-04	1.92E-04	1.32E-05	
Cobalt	3.73E-02	8.95E-03	6.16E-04	
Copper	3.78E-01	9.06E-02	6.23E-03	
D[a,h]anthracen	5.33E-04	1.28E-04	8.80E-06	
Fluoranthene	1.33E-03	3.20E-04	2.20E-05	
Fluorene	1.24E-03	2.98E-04	2.05E-05	
Formaldehyde	3.33E+01	7.99E+00	5.50E-01	
H2S				3.01E+03
Hexane	8.00E+02	1.92E+02	1.32E+01	
In[1,2,3-cd]pyr	8.00E-04	1.92E-04	1.32E-05	
Manganese	1.69E-01	4.05E-02	2.79E-03	
Mercury	1.16E-01	2.77E-02	1.91E-03	
Methanol				4.83E+03
Naphthalene	2.71E-01	6.50E-02	4.47E-03	
NH3	1.03E+03			
Nickel	9.33E-01	2.24E-01	1.54E-02	
p-DiClBenzene	5.33E-01	1.28E-01	8.80E-03	
Phenanthrene	7.55E-03	1.81E-03	1.25E-04	
Pyrene	2.22E-03	5.33E-04	3.67E-05	
Selenium	1.07E-02	2.56E-03	1.76E-04	
Toluene	1.51E+00	3.62E-01	2.49E-02	
Vanadium	1.02E+00	2.45E-01	1.69E-02	

Source: Applicant's Emission Source Modification List, Jan. 2013

Public Health Table 5 (continued)
Operation Phase Annual Emission Rates (lb/yr)

Substance	Rectisol Flare	Gasification Flare	SRU Flare	Diesel Emergency Generator (each of 2 units)	Diesel Firepump
Annual Emissions (lb/yr)					
2MeNaphthalene	4.53E-04	1.71E-03	9.30E-05		
3-MeCholanthren	3.40E-05	1.28E-04	6.97E-06		
7,12-DB[a]anthr	3.02E-04	1.14E-03	6.20E-05		
Acenaphthene	3.40E-05	1.28E-04	6.97E-06		
Acenaphthylene	3.40E-05	1.28E-04	6.97E-06		
Anthracene	4.53E-05	1.71E-04	9.30E-06		
Arsenic	3.78E-03	1.43E-02	7.75E-04		
B[a]anthracene	3.40E-05	1.28E-04	6.97E-06		
B[a]P	2.27E-05	8.56E-05	4.65E-06		
B[b]fluoranthen	3.40E-05	1.28E-04	6.97E-06		
B[g,h,i]perylen	2.27E-05	8.56E-05	4.65E-06		
B[k]fluoranthen	3.40E-05	1.28E-04	6.97E-06		
Benzene	3.97E-02	1.50E-01	8.14E-03		
Beryllium	2.27E-04	8.56E-04	4.65E-05		
Cadmium	2.08E-02	7.85E-02	4.26E-03		
Chromium	2.64E-02	9.99E-02	5.42E-03		
Chrysene	3.40E-05	1.28E-04	6.97E-06		
Cobalt	1.59E-03	5.99E-03	3.25E-04		
Copper	1.61E-02	6.06E-02	3.29E-03		
DieselExhPM				2.25E+01	1.84E+00
D[a,h]anthracen	2.27E-05	8.56E-05	4.65E-06		
Fluoranthene	5.67E-05	2.14E-04	1.16E-05		
Fluorene	5.29E-05	2.00E-04	1.08E-05		
Formaldehyde	1.42E+00	5.35E+00	2.91E-01		
Hexane	3.40E+01	1.28E+02	6.97E+00		
In[1,2,3-cd]pyr	3.40E-05	1.28E-04	6.97E-06		
Manganese	7.18E-03	2.71E-02	1.47E-03		
Mercury	4.91E-03	1.85E-02	1.01E-03		
Naphthalene	1.15E-02	4.35E-02	2.36E-03		
Nickel	3.97E-02	1.50E-01	8.14E-03		
p-DiClBenzene	2.27E-02	8.56E-02	4.65E-03		
Phenanthrene	3.21E-04	1.21E-03	6.59E-05		
Pyrene	9.44E-05	3.57E-04	1.94E-05		
Selenium	4.53E-04	1.71E-03	9.30E-05		
Toluene	6.42E-02	2.43E-01	1.32E-02		
Vanadium	4.34E-02	1.64E-01	8.91E-03		

Source: Applicant's Emission Source Modification List, Jan. 2013

Public Health Table 5 (continued)
Operation Phase Annual Emission Rates (lb/yr)

Substance	**Urea Pastillation**	**U_H Plant Absorber**	**U_L Plant Absorber**	**Nitric Acid Plant**	**Gasification Area Fugitives** (3 sources)
Annual Emissions (lb/yr)					
NH3	8.22E+03	8.97E+04	1.63E+04	8.28E+03	6.60E+02
H2S					2.02E+03
Carbonyl sulfide					2.80E+02

Substance	**H2S and NH3 from Total Fugitives (Shift, AGR, SRU, SWS combined)**	**Shift Area Fugitives** (2 sources) (estimated) (14% of total H2S and NH3)	**AGR Fugitives** (1 source) (estimated) (68% of total H2S and NH3)	**SRU Fugitives** (2 sources) (estimated) (9.4% of total H2S and NH3)	**SWS Fugitives** (1 source) (estimated) (8.4% of total H2S and NH3)
Annual Emissions (lb/yr)					
H2S	2.98E+03	4.17E+02	2.03E+03	2.80E+02	2.50E+02
NH3	8.26E+03	2.23E+03			6.03E+03
HCN	-				3.46E+00
Methanol	-		1.48E+04		
Propylene	-		1.83E+04		

Substance	**Petcoke & Coal Trucks** Running Emissions	**Petcoke & Coal Trucks** Idling Emissions	**Petcoke & Coal Trucks** Running Emissions	**Petcoke & Coal Trucks** Idling Emissions	**Misc. Trucks** Idling Emissions	**On-Site O&M Trucks** Running Emissions
Annual Emissions (lb/yr)						
Diesel PM10	2.8E+00	3.2E-01	1.0E+01	4.4E-01	7.7E-01	5.3E-01

Substance	**On-Site Train**
Annual Emissions (lb/yr)	
Diesel PM10	8.22E+01

Source: Applicant's Emission Source Modification List, Jan. 2013

Public Health Table 6
Operation Phase Maximum Emission Rates (lb/hr)

Substance	CTG/HRSG	Coal Dryer	ASU Cooling Tower (each of 4 units)	Power Block Cooling Tower (each of 12 units)	Process Cooling Tower (each of 13 units)
Annual Emissions (lb/hr)					
Acetaldehyde	4.38E-03	7.72E-04			
Antimony	2.68E-03	4.72E-04			
Arsenic	5.84E-03	1.03E-03	7.22E-07	5.12E-07	8.05E-07
B[a]anthracene	5.59E-06	9.87E-07			
Benzene	5.84E-03	1.03E-03			
Beryllium	6.32E-04	1.12E-04			
Cadmium	2.33E-02	4.12E-03			
Chromium	1.24E-03	2.19E-04			
Cobalt	6.32E-04	1.12E-04			
Copper			1.40E-07	9.95E-08	1.56E-07
Cr(VI)	3.72E-04	6.57E-05			
CS2	1.12E-01	1.97E-02			
Cyanide cmpds	1.39E-02	2.45E-03			
Fluorides&cmpds			1.26E-05	8.95E-06	1.41E-05
Formaldehyde	4.13E-02	7.30E-03			
HCl	3.16E-02	5.58E-03			
HF	1.22E-01	2.15E-02			
Lead	1.36E-03	2.40E-04			
Manganese	2.53E-03	4.46E-04	3.61E-05	2.56E-05	4.02E-05
Mercury	1.21E-03	6.14E-04			
Methyl Bromide	1.16E-01	2.05E-02			
Methylene Chlor	5.35E-03	9.44E-04			
Naphthalene	6.08E-03	1.07E-03			
NH3	1.85E+01	3.20E+00			
Nickel	9.48E-04	1.67E-04			
Phenol	8.95E-02	1.58E-02			
Selenium	1.36E-03	2.40E-04	6.00E-07	4.26E-07	6.69E-07
Sulfuric Acid	2.31E-01	4.08E-02			
Toluene	8.03E-05	1.42E-05			

Source: Applicant's Emission Source Modification List, Jan. 2013

Public Health Table 6 (continued)
Operation Phase Maximum Emission Rates (lb/hr)

Substance	Auxiliary Boiler	Tail Gas Thermal Oxidizer	Ammonia Heater	CO2 Vent
Hourly Emissions (lb/hr)				
2MeNaphthalene	4.87E-06	2.13E-06	1.26E-06	
3-MeCholanthren	3.65E-07	1.59E-07	9.43E-08	
7,12-DB[a]anthr	3.25E-06	1.42E-06	8.38E-07	
Acenaphthene	3.65E-07	1.59E-07	9.43E-08	
Acenaphthylene	3.65E-07	1.59E-07	9.43E-08	
Anthracene	4.87E-07	2.13E-07	1.26E-07	
Arsenic	4.06E-05	1.77E-05	1.05E-05	
B[a]anthracene	3.65E-07	1.59E-07	9.43E-08	
B[a]P	2.43E-07	1.06E-07	6.29E-08	
B[b]fluoranthen	3.65E-07	1.59E-07	9.43E-08	
B[g,h,i]perylen	2.43E-07	1.06E-07	6.29E-08	
B[k]fluoranthen	3.65E-07	1.59E-07	9.43E-08	
Benzene	4.26E-04	1.86E-04	1.10E-04	
Beryllium	2.43E-06	1.06E-06	6.29E-07	
Cadmium	2.23E-04	9.74E-05	5.76E-05	
Carbonyl sulfide				1.06E+01
Chromium	2.84E-04	1.24E-04	7.33E-05	
Chrysene	3.65E-07	1.59E-07	9.43E-08	
Cobalt	1.70E-05	7.44E-06	4.40E-06	
Copper	1.72E-04	7.53E-05	4.45E-05	
D[a,h]anthracen	2.43E-07	1.06E-07	6.29E-08	
Fluoranthene	6.09E-07	2.66E-07	1.57E-07	
Fluorene	5.68E-07	2.48E-07	1.47E-07	
Formaldehyde	1.52E-02	6.64E-03	3.93E-03	
H2S				5.98E+00
Hexane	3.65E-01	1.59E-01	9.43E-02	
In[1,2,3-cd]pyr	3.65E-07	1.59E-07	9.43E-08	
Manganese	7.71E-05	3.37E-05	1.99E-05	
Mercury	5.27E-05	2.30E-05	1.36E-05	
Methanol				2.25E+01
Naphthalene	1.24E-04	5.40E-05	3.20E-05	
NH3	4.69E-01			
Nickel	4.26E-04	1.86E-04	1.10E-04	
p-DiClBenzene	2.43E-04	1.06E-04	6.29E-05	
Phenanthrene	3.45E-06	1.51E-06	8.90E-07	
Pyrene	1.01E-06	4.43E-07	2.62E-07	
Selenium	4.87E-06	2.13E-06	1.26E-06	
Toluene	6.90E-04	3.01E-04	1.78E-04	
Vanadium	4.67E-04	2.04E-04	1.20E-04	

Source: Applicant's Emission Source Modification List, Jan. 2013

Public Health Table 6 (continued)
Operation Phase Maximum Emission Rates (lb/hr)

Substance	Rectisol Flare	Gasification Flare	SRU Flare	Diesel Emergency Generator (each of 2 units)	Diesel Firepump
Hourly Emissions (lb/hr)					
2MeNaphthalene	9.84E-06	6.69E-05	8.30E-07		
3-MeCholanthren	7.38E-07	5.02E-06	6.22E-08		
7,12-DB[a]anthr	6.56E-06	4.46E-05	5.53E-07		
Acenaphthene	7.38E-07	5.02E-06	6.22E-08		
Acenaphthylene	7.38E-07	5.02E-06	6.22E-08		
Anthracene	9.84E-07	6.69E-06	8.30E-08		
Arsenic	8.20E-05	5.57E-04	6.91E-06		
B[a]anthracene	7.38E-07	5.02E-06	6.22E-08		
B[a]P	4.92E-07	3.34E-06	4.15E-08		
B[b]fluoranthen	7.38E-07	5.02E-06	6.22E-08		
B[g,h,i]perylen	4.92E-07	3.34E-06	4.15E-08		
B[k]fluoranthen	7.38E-07	5.02E-06	6.22E-08		
Benzene	8.61E-04	5.85E-03	7.26E-05		
Beryllium	4.92E-06	3.34E-05	4.15E-07		
Cadmium	4.51E-04	3.07E-03	3.80E-05		
Chromium	5.74E-04	3.90E-03	4.84E-05		
Chrysene	7.38E-07	5.02E-06	6.22E-08		
Cobalt	3.44E-05	2.34E-04	2.90E-06		
Copper	3.48E-04	2.37E-03	2.94E-05		
D[a,h]anthracen	4.92E-07	3.34E-06	4.15E-08		
DieselExhPM				4.51E-01	1.84E-02
Fluoranthene	1.23E-06	8.36E-06	1.04E-07		
Fluorene	1.15E-06	7.80E-06	9.68E-08		
Formaldehyde	3.07E-02	2.09E-01	2.59E-03		
Hexane	7.38E-01	5.02E+00	6.22E-02		
In[1,2,3-cd]pyr	7.38E-07	5.02E-06	6.22E-08		
Manganese	1.56E-04	1.06E-03	1.31E-05		
Mercury	1.07E-04	7.25E-04	8.99E-06		
Naphthalene	2.50E-04	1.70E-03	2.11E-05		
Nickel	8.61E-04	5.85E-03	7.26E-05		
p-DiClBenzene	4.92E-04	3.34E-03	4.15E-05		
Phenanthrene	6.97E-06	4.74E-05	5.88E-07		
Pyrene	2.05E-06	1.39E-05	1.73E-07		
Selenium	9.84E-06	6.69E-05	8.30E-07		
Toluene	1.39E-03	9.48E-03	1.18E-04		
Vanadium	9.43E-04	6.41E-03	7.95E-05		

Source: Applicant's Emission Source Modification List, Jan. 2013

Public Health Table 6 (continued)
Operation Phase Maximum Emission Rates (lb/hr)

Substance	Urea Pastillation	U_H Plant Absorber	U_L Plant Absorber	Nitric Acid Plant	Gasification Area Fugitives (3 sources)
Annual Emissions (lb/hr)					
NH3	1.02E+00	1.11E+01	2.02E+00	1.03E+00	8.00E-02
H2S					2.30E-01
Carbonyl sulfide					3.12E-02

Substance	H2S and NH3 from Total Fugitives (Shift, AGR, SRU, SWS combined)	Shift Area Fugitives (2 sources) (estimated) (14% of total H2S and NH3)	AGR Fugitives (1 source) (estimated) (68% of total H2S and NH3)	SRU Fugitives (2 sources) (estimated) (9.4% of total H2S and NH3)	SWS Fugitives (1 source) (estimated) (8.4% of total H2S and NH3)
Annual Emissions (lb/hr)					
H2S	3.4E-01	4.8E-02	2.3E-01	3.2E-02	2.9E-02
NH3	9.4E-01	2.5E-01			6.9E-01
HCN	-				3.92E-04
Methanol	-		1.55E+00		
Propylene	-		2.09E+00		

Substance	Petcoke & Coal Trucks Running Emissions	Petcoke & Coal Trucks Idling Emissions	Petcoke & Coal Trucks Running Emissions	Petcoke & Coal Trucks Idling Emissions	Misc. Trucks Idling Emissions	On-Site O&M Trucks Running Emissions
Annual Emissions (lb/hr)						
Diesel PM10	1.0E-03	1.2E-04	6.2E-03	2.7E-04	2.3E-03	5.3E-04

Substance	On-Site Train
Annual Emissions (lb/hr)	
Diesel PM10	1.3E-01

Source: Applicant's Emission Source Modification List, Jan. 2013

Public Health Table 7
Concentrations of TAC in ug/m3 per g/sec (Chi/Q)

Receptor	PMI Cancer	PMI Chronic HI	PMI Acute HI	MEIR Cancer & Chronic HI	MEIR Acute HI	Elk Hills School, Tupman
UTM-X	*283967*	*283959*	*282663*	*283989.44*	*284402*	*285878*
UTM-Y	*3911925*	*3911625*	*3912844*	*3910951*	*3912477*	*3908605*
Average Annual Chi/Q (43824 hours)						
ug/m3 per g/sec						
Source						
HRSG	0.08093	0.09639	0.00197	0.06712	0.02282	0.0167
Coal Dryer	0.18072	0.19522	0.05013	0.12624	0.04865	0.03022
CO2 Vent	0.14501	0.12478	0.03576	0.07187	0.06744	0.02967
Gas Fug	0.32274	0.36639	0.67832	0.28804	0.1103	0.07907
Shift Fug	1.44886	1.75413	5.25701	1.28408	0.56144	0.20054
AGR Fug	1.53598	1.68779	7.42854	1.22367	0.59061	0.19837
SRU Fug	1.66543	1.55707	14.7561	1.10671	0.62374	0.19659
SWS Fug	1.73131	1.62261	12.4887	1.13608	0.63583	0.19937
1-Hour Chi/Q						
ug/m3 per g/sec						
Source						
HRSG	5.34515	4.51025	0.34249	2.42945	4.11131	1.57579
Coal Dryer	7.99213	6.98234	4.01816	5.53672	4.85115	3.25972
CO2 Vent	11.8686	9.57256	5.17635	6.08023	8.71741	3.44288
Gas Fug	21.145	21.64616	51.9525	17.1368	18.3853	8.2274
Shift Fug	285.858	271.98428	524.188	203.26066	247.153	55.15088
AGR Fug	269.897	309.64707	586.35	195.54528	183.43	48.02912
SRU Fug	259.901	298.12944	787.632	185.78627	218.477	56.4616
SWS Fug	268.455	311.50522	772.941	188.40294	223.36	56.99236

Public Health Table 8
Average Annual GLC and Soil Concentration at the Receptors Evaluated in Staff's Analysis

	Average Annual Ground Level Concentration (GLC), ug/m3						Soil Concentration of Deposited Particulates, mg/kg					
Receptor	PMI Cancer	PMI ChronicHI	PMI Acute HI	MEIR Chronic	MEIR Acute HI	Elk Hills School	PMI Cancer	PMI ChronicHI	PMI Acute HI	MEIR Chronic	MEIR Acute HI	Elk Hills School
Acetaldehyde	1.17E-05	1.36E-05	1.13E-06	9.31E-06	3.27E-06	2.29E-06						
Antimony	7.18E-06	8.32E-06	6.88E-07	5.69E-06	2.00E-06	1.40E-06	2.97E-02	3.44E-02	2.85E-03	2.35E-02	8.27E-03	5.80E-03
Arsenic	1.57E-05	1.82E-05	1.50E-06	1.24E-05	4.36E-06	3.06E-06	6.48E-02	7.51E-02	6.21E-03	5.13E-02	1.80E-02	1.27E-02
B[a]anthracene	1.50E-08	1.74E-08	1.44E-09	1.19E-08	4.18E-09	2.93E-09	2.94E-06	3.41E-06	2.82E-07	2.33E-06	8.19E-07	5.75E-07
Benzene	1.57E-05	1.82E-05	1.50E-06	1.24E-05	4.36E-06	3.06E-06						
Beryllium	1.70E-06	1.97E-06	1.63E-07	1.34E-06	4.72E-07	3.31E-07	7.02E-03	8.14E-03	6.73E-04	5.56E-03	1.95E-03	1.37E-03
Cadmium	6.26E-05	7.26E-05	6.00E-06	4.96E-05	1.74E-05	1.22E-05	2.59E-01	3.01E-01	2.48E-02	2.05E-01	7.22E-02	5.06E-02
Chromium	3.32E-06	3.85E-06	3.19E-07	2.63E-06	9.23E-07	6.48E-07	1.37E-02	1.59E-02	1.32E-03	1.09E-02	3.82E-03	2.68E-03
Cobalt	1.70E-06	1.97E-06	1.63E-07	1.34E-06	4.72E-07	3.31E-07	7.02E-03	8.14E-03	6.73E-04	5.56E-03	1.95E-03	1.37E-03
Cr(VI)	9.97E-07	1.16E-06	9.57E-08	7.90E-07	2.78E-07	1.95E-07	4.13E-03	4.79E-03	3.96E-04	3.27E-03	1.15E-03	8.06E-04
Carbonyl Sulfide	2.48E-03	2.21E-03	1.09E-03	1.33E-03	1.12E-03	5.18E-04						
CS2	3.00E-04	3.48E-04	2.88E-05	2.38E-04	8.35E-05	5.86E-05						
Cyanide cmpds	3.73E-05	4.32E-05	3.57E-06	2.96E-05	1.04E-05	7.28E-06						
Formaldehyde	1.11E-04	1.29E-04	1.06E-05	8.80E-05	3.09E-05	2.17E-05						
H2S	1.64E-02	1.76E-02	7.47E-02	1.27E-02	6.30E-03	2.42E-03						
HCl	8.48E-05	9.83E-05	8.13E-06	6.72E-05	2.36E-05	1.66E-05						
HCN	1.72E-05	1.62E-05	1.24E-04	1.13E-05	6.33E-06	1.99E-06						
HF	3.25E-04	3.77E-04	3.12E-05	2.57E-04	9.04E-05	6.34E-05						
Lead	3.67E-06	4.25E-06	3.51E-07	2.91E-06	1.02E-06	7.16E-07	1.52E-02	1.76E-02	1.45E-03	1.20E-02	4.23E-03	2.96E-03
Manganese	6.79E-06	7.87E-06	6.51E-07	5.38E-06	1.89E-06	1.33E-06	2.81E-02	3.26E-02	2.69E-03	2.23E-02	7.82E-03	5.49E-03
Mercury	3.13E-06	3.48E-06	6.26E-07	2.31E-06	8.54E-07	5.60E-07	1.29E-02	1.44E-02	2.59E-03	9.56E-03	3.53E-03	2.32E-03
Methanol	6.75E-02	7.37E-02	3.17E-01	5.32E-02	2.61E-02	8.87E-03						
Methyl Bromide	3.11E-04	3.61E-04	2.98E-05	2.47E-04	8.66E-05	6.08E-05						
Methylene Chlor	1.44E-05	1.66E-05	1.38E-06	1.14E-05	3.99E-06	2.80E-06						
Naphthalene	1.63E-05	1.89E-05	1.56E-06	1.29E-05	4.54E-06	3.18E-06	3.20E-03	3.71E-03	3.07E-04	2.53E-03	8.90E-04	6.25E-04
NH3	9.00E-02	9.81E-02	2.57E-01	6.81E-02	2.88E-02	1.47E-02						
Nickel	2.54E-06	2.95E-06	2.44E-07	2.02E-06	7.08E-07	4.97E-07	1.05E-02	1.22E-02	1.01E-03	8.34E-03	2.93E-03	2.06E-03
Phenol	2.40E-04	2.79E-04	2.31E-05	1.91E-04	6.69E-05	4.70E-05						
Propylene	8.09E-02	8.89E-02	3.91E-01	6.44E-02	3.11E-02	1.04E-02						
Selenium	3.67E-06	4.25E-06	3.51E-07	2.91E-06	1.02E-06	7.16E-07	1.52E-02	1.76E-02	1.45E-03	1.20E-02	4.23E-03	2.96E-03
Sulfuric Acid	6.20E-04	7.19E-04	5.94E-05	4.91E-04	1.73E-04	1.21E-04						
Toluene	2.15E-07	2.50E-07	2.06E-08	1.71E-07	5.99E-08	4.20E-08						

Public Health Table 9
1-Hour GLC at the Receptors Evaluated in Staff's Analysis

	1-Hour Ground Level Concentration (GLC), ug/m3					
Receptor	PMI Cancer	PMI ChronicHI	PMI Acute HI	MEIR Chronic	MEIR Acute HI	Elk Hills School
Acetaldehyde	3.17E-03	3.17E-03	5.80E-04	1.88E-03	2.74E-03	1.19E-03
Antimony	1.94E-03	1.94E-03	3.55E-04	1.15E-03	1.68E-03	7.27E-04
Arsenic	4.23E-03	4.23E-03	7.74E-04	2.51E-03	3.66E-03	1.58E-03
B[a]anthracene	4.05E-06	4.05E-06	7.42E-07	2.40E-06	3.50E-06	1.52E-06
Benzene	4.23E-03	4.23E-03	7.74E-04	2.51E-03	3.66E-03	1.58E-03
Beryllium	4.58E-04	4.58E-04	8.41E-05	2.72E-04	3.96E-04	1.72E-04
Cadmium	1.69E-02	1.69E-02	3.09E-03	1.00E-02	1.46E-02	6.32E-03
Chromium	8.98E-04	8.98E-04	1.65E-04	5.33E-04	7.77E-04	3.36E-04
Cobalt	4.58E-04	4.58E-04	8.41E-05	2.72E-04	3.96E-04	1.72E-04
Cr(VI)	2.69E-04	2.69E-04	4.94E-05	1.60E-04	2.33E-04	1.01E-04
Carbonyl Sulfide	1.29E+01	1.31E+01	7.12E+00	8.20E+00	1.17E+01	4.63E+00
CS2	8.11E-02	8.11E-02	1.48E-02	4.81E-02	7.01E-02	3.04E-02
Cyanide cmpds	1.01E-02	1.01E-02	1.84E-03	5.97E-03	8.71E-03	3.77E-03
Formaldehyde	2.99E-02	2.99E-02	5.48E-03	1.78E-02	2.59E-02	1.12E-02
H2S	2.08E+01	2.49E+01	3.16E+01	1.34E+01	1.56E+01	5.00E+00
HCl	2.29E-02	2.29E-02	4.19E-03	1.36E-02	1.98E-02	8.57E-03
HCN	5.15E-03	5.15E-03	1.28E-02	3.11E-03	3.69E-03	9.42E-04
HF	8.83E-02	8.83E-02	1.62E-02	5.24E-02	7.64E-02	3.31E-02
Lead	9.85E-04	9.85E-04	1.80E-04	5.84E-04	8.52E-04	3.69E-04
Manganese	1.83E-03	1.83E-03	3.35E-04	1.09E-03	1.58E-03	6.86E-04
Mercury	7.38E-04	7.38E-04	2.86E-04	5.14E-04	5.73E-04	3.12E-04
Methanol	8.77E+01	8.77E+01	1.29E+02	5.55E+01	6.06E+01	1.92E+01
Methyl Bromide	8.40E-02	8.40E-02	1.54E-02	4.99E-02	7.27E-02	3.15E-02
Methylene Chlor	3.87E-03	3.87E-03	7.09E-04	2.30E-03	3.35E-03	1.45E-03
Naphthalene	4.40E-03	4.40E-03	8.05E-04	2.61E-03	3.81E-03	1.65E-03
NH3	4.92E+01	5.83E+01	8.67E+01	3.09E+01	3.90E+01	1.18E+01
Nickel	6.86E-04	6.86E-04	1.26E-04	4.07E-04	5.94E-04	2.57E-04
Phenol	6.48E-02	6.48E-02	1.19E-02	3.85E-02	5.61E-02	2.43E-02
Propylene	8.16E+01	8.16E+01	1.55E+02	5.15E+01	4.83E+01	1.27E+01
Selenium	9.85E-04	9.85E-04	1.80E-04	5.84E-04	8.52E-04	3.69E-04
Sulfuric Acid	1.67E-01	1.67E-01	3.07E-02	9.93E-02	1.45E-01	6.27E-02
Toluene	5.82E-05	5.82E-05	1.07E-05	3.45E-05	5.03E-05	2.18E-05

Public Health Table 10
List of Exposure Assumptions Used in this Analysis

Pathway/Receptor/Parameter	Value	Units	Source
Residential Receptor			
Averaging Time			
Carcinogenic Effects	70	years	OEHHA 2012
Noncarcinogenic Effects, resident	2190	days	DTSC 2005
Exposure Duration			
Third trimester	0.25	years	OEHHA 2012
0<2 age group	2	years	OEHHA 2012
2<16 age group	14	years	OEHHA 2012
16-30 age group	14	years	OEHHA 2012
Age Sensitivity Factor			
Third trimester	10		OEHHA 2012
0<2 age group	10		OEHHA 2012
2<16 age group	3		OEHHA 2012
16-30 age group	1		OEHHA 2012
Exposure Frequency	350	days/yr	OEHHA 2012
Exposure Duration (child, for HI calcs)	6	years	DTSC 2005
Daily Breathing Rate			
Third trimester	361	l/kg/day	OEHHA 2012
0<2 age group	1090	l/kg/day	OEHHA 2012
2<16 age group	745	l/kg/day	OEHHA 2012
16-30 age group	335	l/kg/day	OEHHA 2012
Soil Ingestion Rate			
Third trimester	3	mg/kg/day	OEHHA 2012
0<2 age group	40	mg/kg/day	OEHHA 2012
2<16 age group	10	mg/kg/day	OEHHA 2012
16-30 age group	3	mg/kg/day	OEHHA 2012
Annual Dermal Loading Estimates (assume mixed climate)			
Third trimester	2,400	mg/kg/yr	OEHHA 2012
0<2 age group	2,900	mg/kg/yr	OEHHA 2012
2<16 age group	8100	mg/kg/yr	OEHHA 2012
16-30 age group	2400	mg/kg/yr	OEHHA 2012

Public Health Table 11
Toxicity Values Used in this Analysis

TAC	Cancer PF (Inh) (mg/kg-d)-1	Cancer PF (Oral) (mg/kg-d)-1	Chronic REL (Inh) ug/m3	Inh Ref Dose mg/kg/day	Source	Chronic REL(Oral) mg/kg/day	Source	Acute REL ug/m3	Dermal Abs	Soil Half-Life day	Ks 1/day	X
Source:	(1)	(1)	(1)					(1)		(3)		
Acetaldehyde	1.0E-02		1.4E+02	4.0E-02	REL	4.0E-02	RfDi	4.7E+02	1.0E-01			
Antimony				4.0E-04	RfDo	4.0E-04	(4)		1.0E-02	1.0E+08	6.9E-09	2.3E+00
Arsenic	1.2E+01	1.5E+00	1.5E-02	4.3E-06	REL	3.5E-06	(1)	2.0E-01	6.0E-02	1.0E+08	6.9E-09	2.3E+00
B[a]anthracene*	3.9E-01	1.2E+00	9.0E+00	2.6E-03	*	2.6E-03	RfDi		1.3E-01	4.3E+02	1.6E-03	2.5E+04
Benzene	1.0E-01		6.0E+01	1.7E-02	REL	1.7E-02	RfDi	1.3E+03	1.0E-01			
Beryllium	8.4E+00		7.0E-03	2.0E-06	REL	2.0E-03	(1)		1.0E-02	1.0E+08	6.9E-09	2.3E+00
Cadmium	1.5E+01		2.0E-02	5.7E-06	REL	5.0E-04	(1)		1.0E-03	1.0E+08	6.9E-09	2.3E+00
Chromium				2.0E-02	RfDo	2.0E-02	(5)		1.0E-02	1.0E+08	6.9E-09	2.3E+00
Cobalt				1.7E-06	RfC	3.0E-04	(6)		1.0E-02	1.0E+08	6.9E-09	2.3E+00
Cr(VI)	5.1E+02		2.0E-01	5.7E-05	REL	2.0E-02	(1)		1.0E-02	1.0E+08	6.9E-09	2.3E+00
Carbonyl sulfide*			1.0E+01	2.9E-03	REL	2.9E-03	RfDi	4.2E+01	1.0E-01			
CS2			8.0E+02	2.3E-01	REL	2.3E-01	RfDi	6.2E+03	1.0E-01			
Cyanide cmpds			9.0E+00	2.6E-03	REL	2.6E-03	RfDi	3.4E+02	1.0E-01			
Formaldehyde	2.1E-02		9.0E+00	2.6E-03	REL	2.6E-03	RfDi	5.5E+01	1.0E-01			
H2S			1.0E+01	2.9E-03	REL	2.9E-03	RfDi	4.2E+01	1.0E-01			
HCl			9.0E+00	2.6E-03	REL	2.6E-03	RfDi	2.1E+03	1.0E-01			
HCN			9.0E+00	2.6E-03	REL	2.6E-03	RfDi	3.4E+02	1.0E-01			
HF			1.4E+01	4.0E-03	REL	4.0E-02	(1)	2.4E+02	1.0E-01			
Lead	4.2E-02	8.5E-03							1.0E-02	1.0E+08	6.9E-09	2.3E+00
Manganese			9.0E-02	2.6E-05	REL	2.6E-05	RfDi		1.0E-02	1.0E+08	6.9E-09	2.3E+00
Mercury			3.0E-02	8.6E-06	REL	1.6E-04	(1)	6.0E-01	1.0E-02	1.0E+08	6.9E-09	2.3E+00
Methanol			4.0E+03	1.1E+00	REL	1.1E+00	RfDi	2.8E+04	1.0E-01			
Methyl Bromide			5.0E+00	1.4E-03	REL	1.4E-03	RfDi	3.9E+03	1.0E-01			
Methylene Chloride	3.5E-03		4.0E+02	1.1E-01	REL	1.1E-01	RfDi	1.4E+04	1.0E-01			
Naphthalene	1.2E-01		9.0E+00	2.6E-03	REL	2.6E-03	RfDi		1.3E-01	4.3E+02	1.6E-03	2.5E+04
NH3			2.0E+02	5.7E-02	REL	5.7E-02	RfDi	3.2E+03	1.0E-01			
Nickel	9.1E-01		1.4E-02	4.0E-06	REL	1.1E-02	(1)	2.0E-01	1.0E-02	1.0E+08	6.9E-09	2.3E+00
Phenol			2.0E+02	5.7E-02	REL	5.7E-02	RfDi	5.8E+03	1.0E-01			
Propylene			3.0E+03	8.6E-01	REL	8.6E-01	RfDi		1.0E-01			

PUBLIC HEALTH Table 11(continued)
Toxicity Values Used in this Analysis

TAC	Cancer PF (Inh) (mg/kg-d)-1	Cancer PF (Oral) (mg/kg-d)-1	Chronic REL (Inh) ug/m3	Inh Ref Dose mg/kg/day	Source	Chronic REL(Oral) mg/kg/day	Source	Acute REL ug/m3	Dermal Abs	Soil Half-Life day	Ks 1/day	X
Source:	(1)	(1)	(1)					(1)		(3)		
Selenium			2.0E+01	5.7E-03	REL	5.7E-03	RfDi		1.0E-02	1.0E+08	6.9E-09	2.3E+00
Sulfuric Acid			1.0E+00	2.9E-04	REL	2.9E-04	RfDi	1.2E+02	1.0E-01			
Toluene			3.0E+02	8.6E-02	REL	8.6E-02	RfDi	3.7E+04	1.0E-01			

* Assume Carbonyl sulfide has same toxicity as hydrogen sulfide
** Assume B[a]anthracene has same noncancer toxicity as naphthalene

Sources:
1. (1) HARP Health Table
2. (2) DTSC 1994
3. (3) OEHHA 2003
4. (4) EPA 2012a
5. (5) OEHHA 2009
6. (6) EPA 2012b

Public Health Table 12
Results of Staff's Analysis and the Applicant's Analysis for Cancer Risk and Chronic and Acute Hazard during Operations Phase

	Staff's Analysis (limited sources: HRSG, coal dryer, CO2 vent, gas fugitives, shift fugitives, AGR fugitives, SRU fugitives, SWS fugitives)			Applicant's Analysis (all sources) (Source: Table 5.6-5, HECA 2012e)		
	Cancer Risk (per million)	Chronic HI	Acute HI	Cancer Risk (per million)	Chronic HI	Acute HI
PMI-cancer risk	3.1	0.84	0.85	8.97	-	-
PMI-chronic HI	3.6	0.97	0.95	-	0.42	-
PMI-acute HI	3.0	0.11	0.96	-	-	0.88
MEIR-chronic	2.5	0.66	0.54	4.29	0.29	-
MEIR-acute	0.87	0.23	0.69	-	-	0.33
Nearest school	0.61	0.16	0.24	0.96	0.07	0.11

Note:
HI = Hazard Index
PMI = point of maximum impact:
PMI for cancer risk is located at UTM coordinates 283967E, 3911925N, towards the SE corner of the facility at Tupman Road
PMI for chronic hazard is located at UTM coordinates 283959E, 3911625N, towards the SE corner of the facility at Tupman Road
PMI for acute hazard is located at UTM coordinates 282663E, 3912844N, located NW of the facility
MEIR = maximally exposed individual, residential:
MEIR-chronic is located at a residence on the southeastern side of the property on Tupman Road, UTM coordinates 283989E, 3912477N
MEIR-acute is located at a residence on Tule Park Road near Station Road, UTM coordinates 284401E, 3912477N
Nearest school = located at Elk Hills School in Tupman, UTM coordinates 285878E, 3908605N

Public Health Table 13
Results of Staff's Analysis: Contribution to Total Risk and Hazard by Individual Substances from 8 Sources at the Cancer PMI, Chronic PMI and Acute PMI Cancer PMI

Substance	Contribution to Cancer Risk at the Cancer PMI	Contribution to Noncancer Chronic Hazard at the Cancer PMI	Contribution to Noncancer Acute Hazard at the Cancer PMI
Arsenic	62%	89%	2%
Cadmium	24%	4%	-
Cr(VI)	13%	-	-
Carbonyl Sulfide	-	-	36%
Hydrogen Sulfide	-	1%	58%
Manganese	-	5%	-
Ammonia	-	-	2%

Chronic PMI

Substance	Contribution to Cancer Risk at the Chronic PMI	Contribution to Noncancer Chronic Hazard at the Chronic PMI	Contribution to Noncancer Acute Hazard at the Chronic PMI
Arsenic	62%	89%	2%
Cadmium	24%	4%	-
Cr(VI)	13%	-	-
Carbonyl Sulfide	-	-	33%
Hydrogen Sulfide	-	1%	62%
Manganese	-	5%	-
Ammonia	-	-	2%

Acute PMI

Substance	Contribution to Cancer Risk at the Acute PMI	Contribution to Noncancer Chronic Hazard at the Acute PMI	Contribution to Noncancer Acute Hazard at the Acute PMI
Arsenic	62%	63%	-
Cadmium	24%	3%	-
Cr(VI)	13%	-	-
Carbonyl Sulfide	-	-	18%
Hydrogen Sulfide	-	24%	78%
Manganese	-	4%	-
Ammonia	-	4%	3%
Mercury	-	1%	-

Mercury

Staff made a special effort to ensure that mercury emissions would not result in a hazard to public health. Mercury would be emitted from the following sources:

- CTG/HRSG
- Coal Dryer

- Auxiliary Boiler
- Tail Gas Thermal Oxidizer
- Ammonia heater
- Rectisol Flare
- Gasifier Flare
- SRU Flare

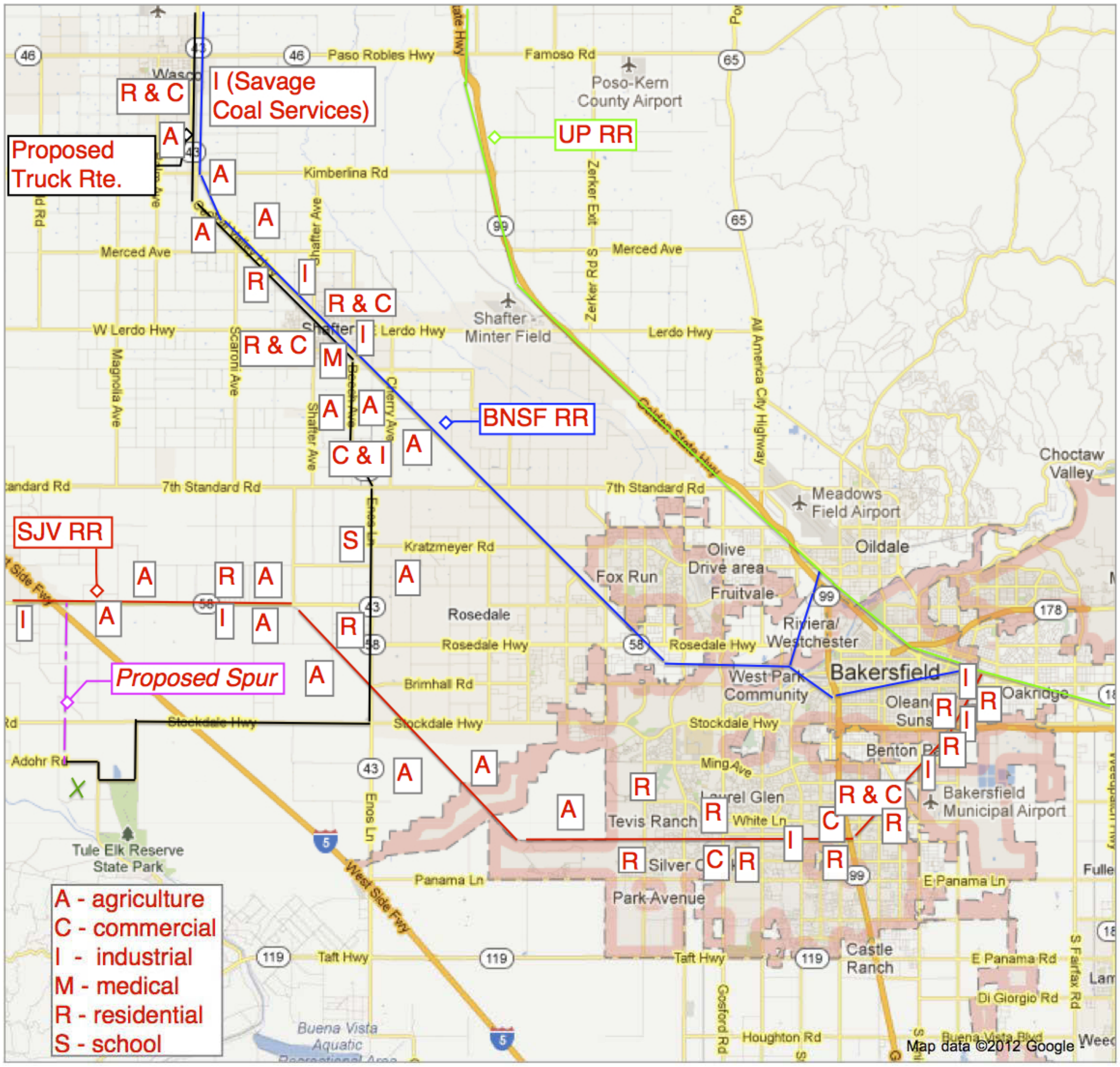
The emissions of mercury from these sources are estimated by the applicant to be very low, ranging from 9E-9 lbs/year from the SRU flare up to 1.2E-3 lbs/yr from the CTD/HRSG. The average annual airborne concentration predicted to occur at off-site receptors according to staff's modeling would range from 5.6E-7 $\mu g/m^3$ at the Elk Hills School to 3.5E-6 $\mu g/m^3$ at the Point of Maximum Impact (near the SE corner of the facility at Tupman Road). Short-term 1-hour airborne concentration would be equally low and is predicted by staff's modeling to be similar at both the Elk Hills School and the Point of Maximum Impact (near the SE corner of the facility at Tupman Road), around 3E-4 $\mu g/m^3$. The chronic Reference Exposure Level (REL) calculated by the Cal-EPA Office of Environmental Health Hazard Assessment (OEHHA) is 3.0E-2 $\mu g/m^3$ and the acute REL is 6.0E-1 $\mu g/m^3$. The average annual airborne concentration of mercury at the Elk Hills School, therefore, is predicted to be 53,000 times lower than the airborne concentration deemed without hazard and the acute 1-hour airborne concentration of mercury at the Elk Hills School is predicted to be 1935 times lower than the airborne concentration deemed without hazard.

In a data request (number 82) issued by Intervener Sierra Club (Sierra Club 2012c) a question was raised as to whether this project would meet the criteria for required compliance with the recent EPA Mercury and Air Toxics Standards ("MATS", effective April 16, 2012). MATS established emission limits for new IGCC electric generating units (such as the HECA project) for among other emissions, mercury (in lbs/GWh). In response to an earlier data request from the staff (number 135, HECA 2012aa), the applicant stated its position, and provided supporting calculations showing, that mercury emissions would comply with the MATS mercury emission limit for IGCC facilities (40 CFR Part63, Subpart UUUUU). Both Air Quality and Public Health staff have reviewed this response and find the estimate of mercury emissions to be credible. Therefore, staff believes that the MATS mercury emissions limit will be met.

Truck & Rail Transportation

Applicant is proposing two options (scenarios) for coal delivery. One option is by a combination of rail and truck, and the other is by truck alone. In either scenario, petroleum coke delivery would be by truck. Staff conducted a driving survey of the proposed coal transportation routes for the HECA project in July 2012. The survey began at the intersection of Highway 46 and Highway 43 in Wasco, where the trucks will pick up coal arriving by rail. The BNSF rail line was noted to parallel Highway 43 between Wasco and the city of Shafter to the southeast. The proposed truck and rail routes are shown in Figure 1, which also shows sensitive receptors and land use designations in the vicinity of the routes. Staff noted agricultural uses adjacent to the majority of the route, significant dust in the air due to agricultural activities and a school located on the truck route (at the intersection of Enos Lane and Kratzmeyer Road). **Public Health Figures 2, 3** and **4** show schools, daycare centers and medical facilities in Wasco, Shafter and Bakersfield, respectively.

Figure 1: Project Area with Sensitive Receptors & Proposed Coal Transportation Routes



Public Health Figure 2
Schools, Daycare Centers and Hospitals near Wasco, CA

schools near wasco ca - Google Maps

schools near **Wasco, Kern, California**   Figure 2a: Wasco Schools

Print

A. Wasco Union High **School** District
2100 7th Street, Wasco, CA
(661) 758-8447

B. Thomas Jefferson Middle **School**
305 Griffith Avenue, Wasco, CA
(661) 758-7140

C. Independence High **School**
1445 Poso Drive, Wasco, CA
(661) 758-7450
1 review

D. North Kern Christian **School**
710 Peters Street, Wasco, CA
(661) 758-5997

E. North Kern Vocational Training
2150 7th Street, Wasco, CA
(661) 758-3045

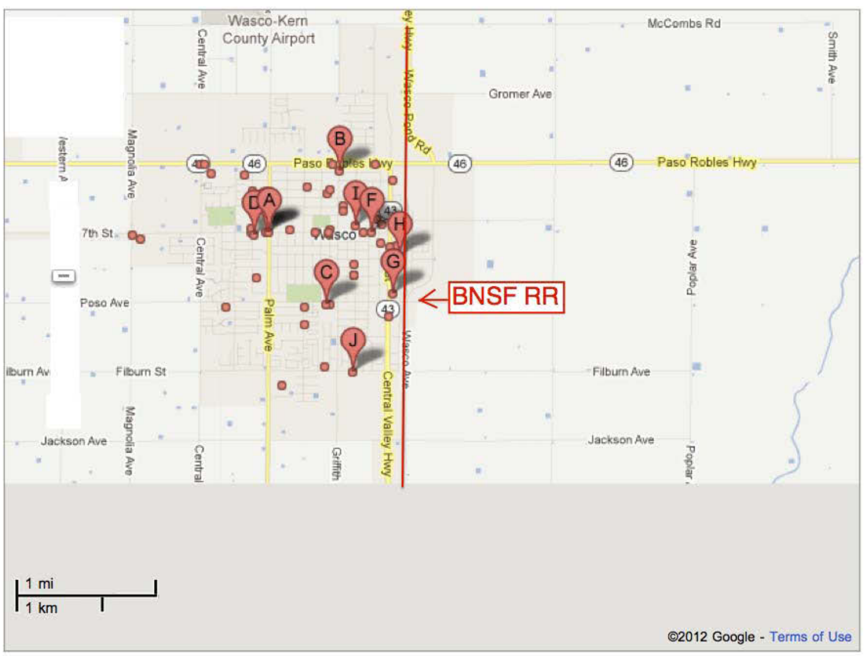
F. Bethany Christian **School**
942 7th Street, Wasco, CA
(661) 758-5906

G. Tigers Karate Taekwondo
1332 F Street, Wasco, CA
(661) 758-5890

H. University of the Pacific
879 G Street, Wasco, CA
(661) 758-0881

I. Wasco Union Elem **School** District
639 Broadway St, Wasco, CA
(661) 758-7100

J. Teresa Burke Elementary **School**
1301 Filburn Street, Wasco, CA
(661) 758-7480
1 review



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Public Health Figure 3
Schools, Daycare Centers and Hospitals near Shafter, CA

schools Shafter, CA - Google Maps

Google **schools** near **Shafter, Kern, California** Figure 3a: Shafter Schools

Print

A. Sequoia Elementary **School**
500 E Fresno Ave, Shafter, CA
(661) 746-8740
1 review

B. Central Valley High **School**
526 Mannel Avenue, Shafter, CA
(661) 746-4961

C. Richland **School** District
331 North Shafter Avenue, Shafter, CA
(661) 746-8600
1 review

D. Free Will Baptist Church
155 Redwood Drive, Shafter, CA
(661) 746-6441

E. Redwood Elementary **School**
331 North Shafter Avenue, Shafter, CA
(661) 746-8614 (Fax)

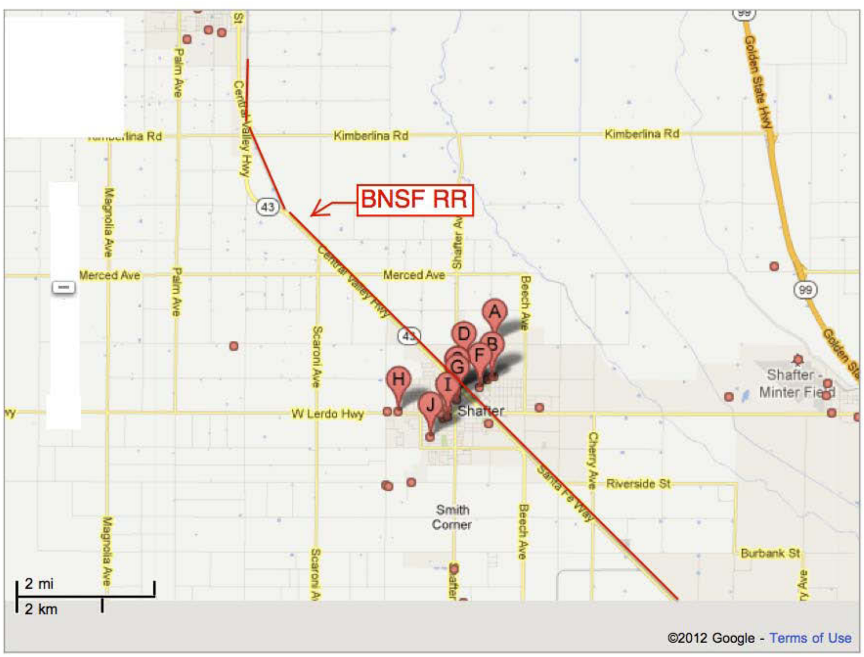
F. Shafter Kiddie Kollege
400 Kern Street, Shafter, CA
(661) 746-4960

G. Richland Junior High **School**
331 Shafter Ave., Shafter, CA, 93263
(661) 746-8630

H. HFS Enterprises
800 West Lerdo Highway, Shafter, CA
(661) 746-9035

I. Golden Oak Elementary **School**
190 South Wall Street, Shafter, CA
(661) 746-8670
2 reviews

J. Community Action Partnership **School**
452 W Los Angeles Ave, Shafter, CA
(661) 746-1443



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Public Health Figure 4
Schools, Daycare Centers and Hospitals near Bakersfield, CA

schools near **Bakersfield, Kern, California** Figure 4a: Bakersfield Schools

Print

A. Foothill High **School**
501 Park Drive, Bakersfield, CA
(661) 366-4491
3 reviews

B. Bakersfield High **School**
1241 G Street, Bakersfield, CA
(661) 324-9841
5 reviews

C. Centennial High **School**
8601 Hageman Road, Bakersfield, CA
(661) 588-8601
2 reviews

D. Golden Valley High **School**
801 Hosking Avenue, Bakersfield, CA
(661) 827-0800
8 reviews

E. Independence High **School**
8001 Old River Road, Bakersfield, CA
(661) 834-8001
2 reviews

F. Stockdale High **School**
2800 Buena Vista Road, Bakersfield, CA
(661) 665-2800
11 reviews

G. Ridgeview High **School**
8501 Stine Road, Bakersfield, CA
(661) 398-3100
3 reviews

H. California State University Bakersfield
9001 Stockdale Highway, Bakersfield, CA
(661) 654-3138
13 reviews

I. Bakersfield Christian High **School**
12775 Stockdale Highway, Bakersfield, CA
(661) 410-7000
4 reviews

J. North High **School**
300 Galaxy Avenue, Bakersfield, CA
(661) 399-3351
6 reviews

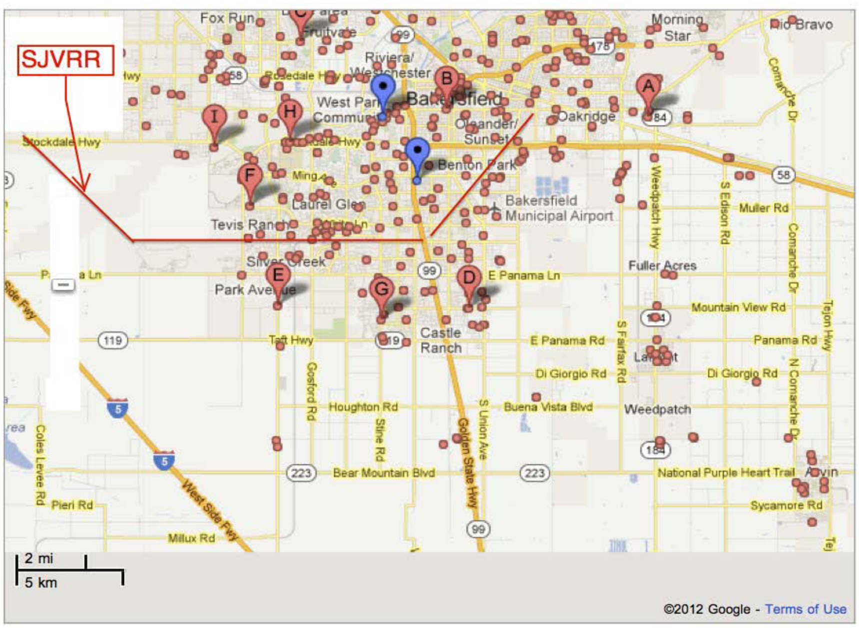

Table 5.1-19 of the Amended AFC (HECA 2012e) lists the anticipated on-site maximum trucks and trains by period for the HECA project – including all truck trips -- and is summarized below. These are the maximum number of truck and train deliveries expected; elimination of one product delivery (anhydrous ammonia) will result in a reduction in-bound and out-bound truck trips; however the applicant has stated in an e-mail to the Energy Commission project managers that the exact reduction will be minor and thus staff should use the numbers below until the applicant refines its assessment. The applicant also indicated that there may be additional materials transported to the site (calcium carbonate flux) and thus this table reflects the best current estimate of all truck trips proposed for project operations:

Truck type	#/hour	#/24 hours	#/year
Petcoke trucks	6	55	15,200
Product trucks	13	130	20,880
Coal trains	1	2	109
Product trains	1	1	153

After driving the coal truck route and other truck routes to/from the proposed facility, staff became concerned about the impacts to public health posed by truck emissions. In a response to a staff data request, the applicant included an assessment of the risk posed to the off-site public located along the transportation routes (HECA 2012dd). This risk would be due to the emissions of diesel particulate matter (DMP) whose toxicity is described earlier in this section. The applicant provided an expanded health risk assessment that included all project stationary and mobile toxic air contaminants (TACs). Emissions from diesel trucks along Station Road were thought by staff to represent the point of greatest emissions of DPM so the applicant assessed impacts at that location and added them to the emissions resulting from stationary sources on the facility site. The risk at other locations along the truck routes would therefore be less than that estimated along Station Road. The maximum estimated risk to a residential receptor along Station Road was calculated by the applicant to be 4.2 in one million under transportation Alternative 1 and 7.2 in a million under transportation Alternative 2 (HECA 2012dd). The Hazard Indices for all non-cancer health impacts was estimated to be much less than 1.0 under both alternatives.

Staff also expressed concern about potential risks posed to sensitive receptors along the truck route transporting pet coke form the Santa Maria area. The applicant, in response to staff's data request, stated that diesel trucks would pass by sensitive receptors on the transportation route between the Conoco Phillips Refinery in Nipomo (near Santa Maria) and the HECA facility, if this option is chosen for the project's petroleum coke (petcoke) needs. According to the applicant (HECA 2012dd), petcoke would not be transported by train for either alternative; therefore, the number of trucks transporting petcoke for either alternative is the same. The route between the Nipomo refinery and the HECA site would include travel on U.S. 101 south to CA 166 east, then to Interstate 5 north, to Stockdale Highway, and finally to Station Road into the HECA facility. Communities passed through would include Nipomo, Cuyama, Maricopa, and southwest Bakersfield. At staff's request, the applicant identified sensitive receptors along the proposed transportation route and the applicant found three schools near an intersection just east of the refinery along the truck route in Nipomo. The schools are

Dana School, Little Bits Preschool, and Dayspring Preschool, all approximately 900 feet southwest of the Pomeroy Road and West Tefft Street intersection in Nipomo. These schools were the closest sensitive receptors located near a signalized intersection along the truck route. Staff felt that idling trucks emitting DPM while stopped at a traffic light near a school along the transportation routed would represent the greatest risk posed to children at any location along the route. The applicant conducted air dispersion modeling and a health risk assessment and estimated that the maximum risk posed to a sensitive receptor along this route would be 0.09 in one million, a level far below the level of significance.

Staff evaluated the applicant’s methodology used in both transportation risk assessments and found it to be consistent with that required by Cal-EPA OEHHA. Staff is thus able to conclude that the applicant’s transportation risk assessment can be relied upon to find that an insignificant risk would be posed to the off-site public by both facility and transportation emissions.

Cooling Towers

In addition to being a source of potential toxic air contaminants, the possibility exists for bacterial growth to occur in the cooling towers, including Legionella. Legionella is a bacterium that is ubiquitous in natural aquatic environments and is also widely distributed in man-made water systems. It is the principal cause of legionellosis, otherwise known as Legionnaires’ Disease, which is similar to pneumonia. Transmission to people results mainly from inhalation or aspiration of aerosolized contaminated water. Untreated or inadequately treated cooling systems, such as industrial cooling towers and building heating, ventilating, and air conditioning systems, have been correlated with outbreaks of legionellosis.

Legionella can grow symbiotically with other bacteria and can infect protozoan hosts. This provides Legionella with protection from adverse environmental conditions, including making it more resistant to water treatment with chlorine, biocides, and other disinfectants. Thus, if not properly maintained, cooling water systems and their components can amplify and disseminate aerosols containing Legionella.

The State of California regulates recycled water for use in cooling towers in Title 22, Section 60303, California Code of Regulations. This section requires that, in order to protect workers and the public who may come into contact with cooling tower mists, chlorine or another biocide must be used to treat the cooling system water to minimize the growth of Legionella and other micro-organisms. This regulation does not apply to the HECA project since it intends to use brackish water provided by the Buena Vista Water Storage District (BVWSD) that would be treated on-site (URS, Section 2.1). However, the potential remains for Legionella growth in cooling water at HECA due to nutrients that are found in groundwater.

The U.S. EPA published an extensive review of Legionella in a human health criteria document (EPA 1999). The U.S. EPA noted that Legionella may propagate in biofilms (collections of microorganisms surrounded by slime they secrete, attached to either inert or living surfaces) and that aerosol-generating systems such as cooling towers can aid in the transfer of Legionella from water to air. The U.S. EPA has inadequate quantitative data on the infectivity of Legionella in humans to prepare a dose-response evaluation.

Therefore, sufficient information is not available to support a quantitative characterization of the threshold infective dose of Legionella. Thus, the presence of even small numbers of Legionella bacteria presents a risk - however small - of disease in humans.

In February of 2000 the Cooling Technology Institute (CTI) issued its own report and guidelines for the best practices for control of Legionella (CTI 2000). The CTI found that 40-60 percent of industrial cooling towers tested were found to contain Legionella. More recently, staff has received a 2005 report of testing in cooling towers in Australia that found the rate of Legionella presence in cooling tower waters to be extremely low, approximately three to six percent. The cooling towers all had implemented aggressive water treatment and biocide application programs similar to that required by proposed Condition of Certification **PUBLIC HEALTH-4**.

To minimize the risk from Legionella, the CTI noted that consensus recommendations included minimization of water stagnation, minimization of process leads into the cooling system that provide nutrients for bacteria, maintenance of overall system cleanliness, the application of scale and corrosion inhibitors as appropriate, the use of high-efficiency mist eliminators on cooling towers, and the overall general control of microbiological populations.

Good preventive maintenance is very important in the efficient operation of cooling towers and other evaporative equipment (ASHRAE 1998). Preventive maintenance includes having effective drift eliminators, periodically cleaning the system if appropriate, maintaining mechanical components in good working order, and maintaining an effective water treatment program with appropriate biocide concentrations. Staff notes that most water treatment programs are designed to minimize scale, corrosion, and biofouling and not to specifically control Legionella.

The efficacy of any biocide in ensuring that bacterial and in particular Legionella growth, is kept to a minimum is contingent upon a number of factors including but not limited to proper dosage amounts, appropriate application procedures and effective monitoring.

In order to ensure that Legionella growth is kept to a minimum, thereby protecting both nearby workers as well as members of the public, staff has proposed Condition of Certification **PUBLIC HEALTH-4**. The condition would require the project owner to prepare and implement a biocide and anti-biofilm agent monitoring program to ensure that proper levels of biocide and other agents are maintained within the cooling tower water at all times, that periodic measurements of Legionella levels are conducted, and that periodic cleaning is conducted to remove bio-film buildup. Staff believes that with the use of an aggressive antibacterial program coupled with routine monitoring and biofilm removal, the chances of Legionella growing and dispersing would be reduced to insignificance.

ENHANCED OIL RECOVERY FACILITY (EOR)

The Enhanced Oil Recovery (EOR) component at Occidental of Elk Hills, Inc. (OEHI) is located approximately four miles south of the proposed HECA project (OXY 2012). Carbon dioxide is a byproduct at HECA and it is proposed to be compressed and delivered by pipeline to the EOR project where it would be injected into the oil wells to help in the recovery of naturally trapped oil. The project is expected to result in the sequestration of approximately three (3) million tons of CO_2 per year during the demonstration phase. This rate of sequestration would also be required for the operational life of the power plant due to the requirements of California law (SB 1368) and the value created by the use of the CO_2 for EOR. The captured CO_2 would be compressed and transported via pipeline to the Elk Hills Oil Field. The CO_2 would enhance domestic oil production, contributing to the nation's energy security. An additional small amount of the CO_2 produced by the facility would be used to manufacture urea.

The EOR process involves the injection and reinjection of CO_2 to reduce the viscosity and enhance other properties of trapped oil in order to facilitate its flow through the reservoir, improving extraction. During EOR operations, the pore space left by the extracted oil is occupied by the injected CO_2, sequestering it in the geologic formation. EOR operations would be monitored to ensure that the injected CO_2 remains within the formation.

Air emissions of TACs would occur during operations at the EOR facility and would come from permitted stationary sources including process heaters, tanks, fugitive, maintenance activities on emergency diesel equipment, emergency flares, and mobile sources. In a response to a data request (OEHI Response to CEC Workshop Request No. A38 Response to CEC Supplemental Questions Regarding Data Request A28), OEHI stated that construction, well workover, and well drilling are ongoing daily activities at Elk Hills and the same basic processes will continue with the development of the CO_2 EOR project and that emissions from the equipment used for conducting these activities will remain controlled as per California regulations. Specifically, they use cleaner (higher Tier) engines in each project year as a result of California and USEPA requirements for off road construction equipment and off road mobile sources.

Therefore, given the small number of sources, the absence of stacks at the EOR facility, the use of cleaner (higher Tier) engines, and the distance to any public off-site receptor, it is extremely unlikely that emissions from the EOR project would result in a significant risk to public health.

Insofar as a cumulative risk from the HECA site and the EOR site combined, since the EOR component is located ~3 miles form the proposed HECA site and the maximum cancer risk and non-cancer hazard index (both acute and chronic) for operations emissions from the HECA project estimated independently by the applicant, staff, and the SJVAPCD are all below the level of significance, it is doubtful that cumulatively a less than significant risk would result in a significant risk when these two parts of the project are added together. Staff has found in the past when evaluating other power plant projects that while air quality cumulative impacts can occur with sources within a 6-mile radius, cumulative public health impacts are not significant unless the emitting sources are extremely close to each other, within a few blocks, not miles. Staff therefore concludes that the proposed HECA project, when combined with the EOR project, would not contribute to cumulative impacts in the area of public health.

AIR DISTRICT PRELIMINARY DETERMINATION OF COMPLIANCE (PDOC)

The SJVUAPCD issued a Preliminary Determination of Compliance (PDOC) on February 17, 2013 and included a health risk assessment (SJVUAPCD 2013a). The SJVUAPCD conducted its assessment using AERMOD and HARP and found that the maximum predicted cancer risk at the PMI would be 8.97 E-6, the maximum chronic HI would be 0.42, and the maximum acute HI would be 0.88. These values are exactly the same as those presented by the applicant (see **Public Health Table 12** above) and serve to confirm that the applicant conducted its health risk assessment properly in accordance with Cal-EPA guidelines. The air district also found that emissions from the HRSG stack/Coal Dryer Unit contributed the most to risk (3.68 E-6) and would be required by district policy to implement T-BACT (Toxics Best Available Control Technology). In this case, T-BACT is defined by the SJVAPCD as the "emission limitation or control technique that is not less stringent than the emission limitation achieved in practice by the best controlled similar source, and reflects the maximum degree of reduction in emissions that the APCO determines is achievable for the new or reconstructed source." In making this determination, the air district considers the "cost of achieving the reduction, non-air quality health impacts, other environmental impacts and energy requirements". According to the PDOC, T-BACT is triggered only for unit S-7616-26-0 which is the Combustion Turbine Generator that will use syngas as the fuel (SJVUAPCD 2013a, Section 10.3 of Appendix K). Particulate matter and VOCs (volatile organic compounds) will thus need to be controlled by the best technology available which reduces emissions to the levels required by the PDOC.

The Air District issued an extensive list of permit conditions which included requirements for source testing of TACs (HAPs) for the project if it is built and operated. Specifically, the project owner would be required to conduct an initial speciated HAPs (TACs) and total VOC source test for the CO_2 recovery and vent and emissions and for the combustion turbine generator. Additionally, the vent stream composition of VOCs (Volatile Organic Chemicals), H_2S (hydrogen sulfide), COS (carbonyl sulfide), and the HAPs identified in the initial speciated HAPs and total VOC source test, would be measured during each venting occurrence exceeding 500,000 scf/day. Ongoing compliance would be determined using mass flow and VOC sampling during venting occurrences as described in another permit condition.

These requirements for testing for HAPs (TACs) are similar to but not the same as staff's recommendations in conditions **PUBLIC HEALTH-1** and **2**. Staff is open to melding the two so as to allow for the same testing to provide both the SJVUAPCD and the Energy Commission the information it needs.

ALTERNATIVES

Staff has reviewed four potential alternative sites from the perspective of public health impacts due to emissions of toxic air contaminants from all the sources identified above. Of all possible alternative site locations, none were environmentally superior to the project site and therefore the project site was selected (HECA 2012e, Section 6.3.1). Because the cancer risk and hazard indices are below the level of significance at the point of maximum impact, staff believes that regardless of the exact location of this facility within this region, the project would not pose a significant risk to public health.

Therefore, staff concludes that there is no preferable alternative location for public health.

CUMULATIVE IMPACTS AND MITIGATION

A project may result in a significant adverse cumulative impact where its effects are cumulatively considerable. "Cumulatively considerable" means that the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects (California Code Regulation, Title 14, section 15130). NEPA states that cumulative effects can result from individually minor but collectively significant actions taking place over a period of time (40 CFR §1508.7).

Cumulative impacts of the proposed project and other projects within a 6-mile radius were not quantitatively evaluated in the AFC. The applicant stated that there are no existing or planned TAC emission sources in the project vicinity that could contribute to a public health cumulative impact (HECA 2012e, Section 5.6.4).

COMPLIANCE WITH LORS

Staff has considered the minority population as identified in **Socioeconomics Figure 1** in its impact analysis and has found no potential significant adverse impacts for any receptors, including environmental justice populations. In arriving at this conclusion, staff notes that its analysis complies with all directives and guidelines from the Cal/EPA Office of Environmental Health Hazard Assessment and the California Air Resources Board. Staff's assessment is biased toward the protection of public health and takes into account the most sensitive individuals in the population. Using extremely conservative (health-protective) exposure and toxicity assumptions, staff's analysis demonstrates that members of the public potentially exposed to toxic air contaminant emissions of this project—including sensitive receptors such as the elderly, infants, and people with pre-existing medical conditions—will not experience any acute or chronic significant health risk or any significant cancer risk as a result of that exposure. Staff believes that it incorporated every conservative assumption called for by state and federal agencies responsible for establishing methods for analyzing public health impacts. The results of that analysis indicate that, based upon the best information and data available, there would be no direct or cumulative significant public health impact to any population in the area. Therefore, given the absence of any significant health impacts, there are no disparate health impacts and there are no environmental justice issues associated with **Public Health**. However, because staff recognizes that this exact conglomeration of industrial sources and emissions do not now exist, and to ensure there would be no significant adverse public health impacts, staff recommends Conditions of Certification **PUBLIC HEALTH-1, 2,** and **3.**

Staff concludes that construction and operation of HECA will be in compliance with all applicable LORS regarding long-term and short-term project impacts in the area of **Public Health**.

DIRECT AND INDIRECT IMPACTS OF THE NO-ACTION ALTERNATIVE

Under the No-Action Alternative, DOE would not provide financial assistance to the applicant for the HECA Project. The applicant could still elect to construct and operate its project in the absence of financial assistance from DOE, but DOE believes this is unlikely. For the purposes of analysis in the PSA/DEIS, DOE assumes the project would not be constructed under the No-Action Alternative. Accordingly, the No-Action Alternative would have no impacts associated with this resource area.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

Comment: Trudy Douglass of Bakersfield submitted comments to the Energy Commission and Kern County, dated June 20, July 5 and August 2, 2012. Ms. Douglass raised concerns regarding the existing poor health conditions in Kern County and the poor air quality reported in Kern County.

Response: Staff has researched these issues and our report can be found above in the "Existing Public Health Concerns" section of this section of the PSA.

Comment: Chris Romanini of Buttonwillow raised questions regarding transportation emissions and risks, and the impact of facility emissions on nearby crops. All these concerns were reiterated by the Association of Irritated Residents (AIR) in their "Air Status Report & Data Requests" dated October 24, 2012, which was a compilation of written questions by residents, landowners and employees from the area near the proposed HECA project.

Response: Staff has reviewed the HRA prepared by the applicant which included the assessment of impacts due to mobile emission sources and has determined that the applicant's assessment -- showing that risks due to mobile emissions, both incrementally and cumulatively with stationary sources, would be less than significant -- was conducted appropriately according to Cal-EPA risk assessment guidelines and procedures. Thus, staff agrees that the risks posed by mobile sources would be less than significant.

Comment: The Sierra Club (in scoping comments dated July 27, 2012), suggested using an alternative fuel, such as a higher percentage of petcoke versus coal or the addition of biomass as fuel to reduce emissions of pollutants. Other changes suggested that could reduce emissions included use of an air cooling system rather than the proposed water cooling system and exploring alternatives to elevated flares (such as enclosed ground flare and flare recovery system). The Sierra Club's concerns also encompassed air pollution impacts from rail and truck emissions along the transportation route that would degrade air quality and adversely impact human health and also the potential for high mercury emissions (and subsequent contamination of nearby lands and crops) from coal combustion.

Response: Comments and suggestions noted. However, since the project as proposed would not posed significant risk to the public, no additional assessment of public health impacts was conducted. Please review the Alternatives section of this PSA for further discussion.

CONCLUSIONS

Staff has analyzed potential public health risks associated with construction and operation of the HECA project and does not expect any significant risk of cancer or any short-term or long-term health effects to any members of the public, including low income and minority populations, from project toxic emissions. Staff also concludes that its analysis of potential health impacts from the proposed HECA uses a conservative health-protective methodology that accounts for impacts to the most sensitive individuals in a given population, including a developing fetus, newborns, infants, and the elderly. According to the results of staff's health risk assessment, emissions from HECA would not contribute significantly or cumulatively to morbidity or mortality in any age or ethnic group residing in the project area. Staff has also considered the potential for adverse air quality impacts to the minority population surrounding the site. With the adoption of the recommended conditions of certification, the project's direct and cumulative air quality impacts would be reduced to less than significant. Therefore, the project will not result in a significant or adverse impact to an identified environmental justice population.

However, staff wishes to note that the applicant and staff were not able to quantitatively describe and assess the short-term fluctuations of emissions of TACs under start-up, commissioning, or upset operating conditions. Staff notes, however, that short-term fluctuations in TAC emissions are not expected to impact long-term (chronic) impacts on public health; only acute (short-term) impacts on public health could be possible. Yet, the potential for short-term impacts due to start-up or upset conditions would be reduced to below a level of significance by the immediate identification and control of these releases. Modeling and measurements of "indicator" emissions (the criteria pollutants), measurements of operating conditions by continuous emission monitoring (CEM), onsite measurements of accidental and fugitive chemical releases, and the monitoring of process efficiency parameters (temperature, feed rates, pressure, flow, etc.) would enable the facility to ensure that short-term releases, which will invariably occur, would be kept to a minimum and not result in a significant impact on the nearby public or on-site workers. In order to ensure that long-term routine operating emissions would not, as estimated, pose a significant risk to the off-site public, staff proposes that routine sampling of certain TACs that pose the greatest potential risk and hazard to the public be required and that a health risk assessment be conducted, as per the requirements and schedule of Conditions of Certification **PUBLIC HEALTH-1, PUBLIC HEALTH-2,** and **PUBLIC HEALTH-3**.

Staff believes that this step-by-step approach will serve to inform the project owner, the air district, and the CPM that emissions of TACs and the risks posed to public health remain below the regulatory thresholds. The first step (required in **PUBLIC HEALTH-1,**) is for the project owner to prepare and submit for approval protocols for testing emissions from certain specific sources for the TACs that staff has found contribute the most to risk. The project owner would also have to prepare and submit for approval a protocol for how the human health risk assessments are to be prepared. Once the CPM approves these protocols, testing can take place and the health risk assessment prepared using the test results, as required by **PUBLIC HEALTH-2**. If any human health risk assessment prepared using those source tests should show that the risks to public health are greater than 10 in one million or a Hazard Index is greater than 1.0, the project owner would then be required by **PUBLIC HEALTH-3** to submit plans to address this matter by either submitting a protocol for a more refined health risk assessment or plans for the reduction in the emissions of certain TACs. The allowance for the submission of a more refined health risk assessment is provided for in Cal-EPA OEHHA risk assessment guidelines and is a reflection of the fact that a human health risk assessment over-estimates the true risk posed by a facility but if the risks are less than the regulatory threshold of 10 in one million, no further assessment is needed. A more refined assessment uses better and more accurate air dispersion methods and exposure assumptions. The option to reduce emissions of certain TACs might be the preferred method if the increased calculated risk was the result of a temporary upset condition that can be preventively engineered.

PUBLIC HEALTH-4 would require the project owner to ensure that the cooling water in the cooling tower is free from bacterial contamination to the extent practicable.

PROPOSED CONDITIONS OF CERTIFICATION

PUBLIC HEALTH-1 Not less than sixty (60) days prior to the start of commissioning, the project owner shall prepare protocols describing the sampling and analysis of the Toxic Air Contaminants (TACs) listed below (source tests) and for the preparation of a Human Health Risk Assessments (HRA) and shall submit these protocols to the San Joaquin Valley Air Pollution Control District (SJVAPCD) for review and comment and to the CPM for review and approval. The source testing and HRA shall include the quantitative analysis and assessment of the following toxic air contaminants from all sources at the project site: arsenic, cadmium, hexavalent chromium, mercury, carbon disulfide, and hydrogen sulfide.

Verification: Not later than sixty (60) days prior to the anticipated start of commissioning, the project owner shall provide a copy of the source test and human health risk assessment protocols to the SJVAPCD for review and comment and to the CPM for review and approval.

PUBLIC HEALTH-2 Not later than sixty (60) days after the start of commissioning, the project owner shall conduct source tests as described by the protocol prepared as per the requirement of PH-1. Not later than thirty (30) days after the source test, the project owner shall prepare and submit the results of the source test and the Human Health Risk Assessment (HRA) to the SJVAPCD for review and comment and the CPM for review and approval.

Not later than sixty (60) days after the start of commercial operations, the project owner shall conduct another source test and prepare a new HRA and submit those results to the SJVAPCD for review and comment and the CPM for review and approval thirty (30) days after the source test is completed.

The project owner shall repeat the source test and HRA after 3 years of commencing commercial operations, and then every 5 years thereafter.

Verification: Not later than sixty (60) days after the start of commissioning, the project owner shall provide a letter to the CPM that the source test has been completed and not later than thirty (30) days after the source test, copy of the source test results and the HRA results shall be provided to the SJVAPCD for review and comment and to the CPM for review and approval.

Not later than seven (7) days after every subsequent source test, the project owner shall provide a letter to the CPM that the source test has been completed and not later than thirty (30) days after the source test, copy of the source test results and the HRA results shall be provided to the SJVAPCD for review and comment and to the CPM for review and approval.

PUBLIC HEALTH-3 Not later than sixty (60) days after the submittal to the CPM of the results of any source test and any human health risk assessment prepared using those source test results that shows the risks to be greater than 10 in one million or a Hazard Index of greater than 1.0, the project owner shall submit plans to address this matter by either submitting a protocol for a more refined health risk assessment or plans for the reduction in the emissions of certain TACs to the SJVAPCD for review and comment and to the CPM for review and approval.

The project owner shall repeat this after every source test and HRA preparation.

Verification: Not later than sixty (60) days after any source test and preparation of a HRA, the project owner shall provide a letter to the CPM stating whether or not the HRA results show the risks to be greater than 10 in one million and the Hazard Index to be less than 1.0. If either threshold is exceeded, the project owner shall submit plans to address this matter by either submitting a protocol for a more refined health risk assessment or plans for the reduction in the emissions of certain TACs to the SJVAPCD for review and comment and to the CPM for review and approval.

PUBLIC HEALTH-4 The project owner shall develop and implement a Cooling Water Management Plan to ensure that the potential for bacterial growth in cooling water is kept to a minimum. The Plan shall be consistent with either staff's "Cooling Water Management Program Guidelines" or with the Cooling Technology Institute's "Best Practices for Control of Legionella" guidelines, but in either case, the Plan must include sampling and testing for the presence of Legionella bacteria at least every six months. After two years of power plant operations, the project owner may ask the CPM to reevaluate and revise the Legionella bacteria testing requirement.

Verification: At least 60 days prior to the commencement of cooling tower operations, the Cooling Water Management Plan shall be provided to the CPM for review and approval.

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PUBLIC HEALTH APPENDIX A: HEALTH RISK ASSESSMENT ALGORITHMS

A.1 Concentration Algorithms

A.1.1 Air Concentration

Air dispersion effects carry substances emitted from the proposed facility to off-site locations. This effect is quantified through air dispersion modeling (in this case AERMOD) which predicts the ground level concentration at specific off-site receptors, normalized to the g/sec emission rate of each substance from each source. The off-site ground level air concentration is estimated using the algorithm presented below.

$$C_{air} = \text{Chi/Q} \times \text{E-rate}$$

where

C_{air}	=	chemical concentration in air, µg/m^3
Chi/Q	=	concentration normalized to 1 g/sec, µg/m^3 per g/sec
E-rate	=	average annual or 1-hour emission rate for each substance from each source, g/sec

A.1.2 Soil Concentration

Off-site receptors are potentially exposed via soil ingestion and dermal contact to soil due to emitted particulates deposited to the ground off-site. The off-site soil concentration resulting from this process is predicted using the deposition algorithm presented below.

$$C_{soil} = \frac{C_{air} \times Dep \times X \times CF}{K_s \times SD \times BD \times T_t}$$

where

C_{soil}	=	chemical concentration in soil, mg/kg
C_{air}	=	chemical concentration in air, µg/m^3
Dep	=	deposition rate (uncontrolled sources), 0.05 m/sec
CF	=	conversion factor, 86,400 sec/day
K_s	=	soil elimination constant, 0.693/chemical half-life, day^{-1}
SD	=	soil mixing depth, 0.01 m
BD	=	soil bulk density, 1333 kg/m^3
T_f	=	total number of days of soil deposition, 25550 days
T_o	=	initial time of exposure, 0 days
T_t	=	total days of exposure period, $T_f - T_o$, 25550 days
X	=	integral function, 25549 days

$$X = [\{e\text{^}(-K_s \times T_f) - e\text{^}(-K_s \times T_o)\}] + T_t$$

A.2 Dose & Risk Algorithms

A.2.1 Inhalation

The algorithm used under OEHHA 2012 methodology to calculate intake via inhalation is described below. It is assumed that 100 percent of the inhalation dose is absorbed by the body.

$DOSE_{air}$ = C_{air} x BR/BW x EF x CF

where

$DOSE_{air}$	= dose from inhalation of resuspended dusts, mg/kg/day
C_{air}	= concentration of resuspended dusts in air, µg/m^3
BR/BW	= 95th percentile daily breathing rate normalized to body weight, l/kg-day (361 l/kg-day for third trimester of pregnacy, 1090 l/kg-day for ages 0 to <2, 745 l/kg-day for ages 2 to <16, 335 l/kg-day for ages 16-30)
EF	= exposure frequency (350 days/365 days)
CF	= conversion factor, 10^{-6} mg/µg-m^3/l

A.2.2 Soil Ingestion

Dose due to soil ingestion, assuming 100 percent gastrointestinal absorption, is determined according to:

$DOSE_{soil}$ = C_{soil} x SIR x EF x CF

where

$DOSE_{soil}$	= dose from soil ingestion, mg/kg/day
C_{soil}	= concentration in soil, mg/kg
SIR	= 95th percentile soil ingestion rate, mg/kg/day (3 mg/kg/day for third trimester, 40 mg/kg/day for ages 0 to <2, 10 mg/kg/day for ages 2 to <16, 3 mg/kg/day for ages 16-30)
EF	= exposure frequency (350 days/365 days)
CF	= conversion factor, 10^{-6} kg/mg

A.2.3 Dermal Contact

The algorithm to determine absorbed dose via dermal contact is given below. The proposed project is assumed to be in a warm climate area for purposes of the dermal exposure analysis.

$DOSE_{derm}$ = C_{soil} x ADL x ABS x EF x CF

where

$DOSE_{derm}$	= dose from dermal absorption, mg/kg/day
C_{soil}	= concentration in soil, mg/kg
ADL	= 95th percentile annual dermal load for warm climate, mg/kg/yr (2600 mg/kg/day for third trimester, 4300 mg/kg/day for ages 0 to <2, 8500 mg/kg/day for ages 2 to <16, 2600 mg/kg/day for ages 16-30)

EF	= exposure frequency (350 days/365 days)
CF	= conversion factor, 10^{-6} kg/mg

A.2.4 Risk

Risk due to each pathway is calculated according to the following algorithm and total risk is found by adding risks from each pathway:

$$RISK_i = \frac{DOSE_i \times CPF \times ASF \times ED}{AT}$$

where

$RISK_i$	= risk due to each exposure pathway
CPF	= substance-specific cancer potency factor for inhalation and oral exposures, $(mg/kg/day)^{-1}$
ASF	= age sensitivity factor (10 for third trimester, 10 for ages 0 to <2, 3 for ages 2 to <16, 1 for ages 16-30)
ED	= exposure duration, years (0.25 years for third trimester, 2 years for age 0 to <2, 14 years for ages 2 to <16, 14 years for ages 16-30)
AT	= averaging time for carcinogenic effects, 70 yrs

A.3 Dose & Hazard Algorithms

A.3.1 Inhalation

Hazard due to inhalation of substances emitted from the proposed project is calculated using a high-end estimate of dose based on the 95th percentile value for daily breathing rate normalized to body weight for the most sensitive age group, 0 to <2 years old. Consistent with prior guidance, the exposed child is evaluated for an exposure duration of 6 years. Using the daily breathing rate for the 0 to <2 age range for a period of 6 years is a conservative assumption that likely overestimates actual hazard. In this screening assessment, hazard is not delineated by target organ.

$$DOSE_{air} = \frac{C_{air} \times BR/BW \times EF \times ED \times CF}{AT}$$

where

$DOSE_{air}$	= dose from inhalation of resuspended dusts, mg/kg/day
C_{air}	= concentration of resuspended dusts in air, $\mu g/m^3$
BR/BW	= 95th percentile daily breathing rate normalized to body weight, l/kg-day (1090 l/kg-day for ages 0 to <2)
EF	= exposure frequency (350 days/365 days)
ED	= exposure duration (6 years as child)
CF	= conversion factor, 10^{-6} mg/µg-m^3/l
AT	= averaging time for noncarcinogenic effects (6 years as child)

A.3.2 Soil Ingestion

Hazard due to soil ingestion is based on the 95th percentile value for soil ingestion for the most sensitive age group, 0 to <2 years old.

$$DOSE_{soil} = \frac{C_{soil} \times SIR \times EF \times ED \times CF}{AT}$$

where

- $DOSE_{soil}$ = dose from soil ingestion, mg/kg/day
- C_{soil} = concentration in soil, mg/kg
- SIR = 95th percentile soil ingestion rate, mg/kg/day (40 mg/kg/day for ages 0 to <2)
- EF = exposure frequency (350 days/365 days)
- ED = exposure duration (6 years as child)
- CF = conversion factor, 10^{-6} kg/mg
- AT = averaging time for noncarcinogenic effects (6 years as child)

A.3.3 Dermal Contact

Hazard due to dermal contact is based on the 95th percentile value for annual dermal load for the most sensitive age group, 2 to <16 years old.

$$DOSE_{derm} = \frac{C_{soil} \times ADL \times ABS \times ED \times CF_1 \times CF_2}{AT}$$

where

- $DOSE_{derm}$ = dose from dermal absorption, mg/kg/day
- C_{soil} = concentration in soil, mg/kg
- ADL = 95th percentile annual dermal load for mixed climate, mg/kg/yr (8100 mg/kg/day for ages 2 to <16)
- ABS = substance-specific fraction absorbed across skin
- ED = exposure duration (6 years as child)
- CF_1 = conversion factor, 10^{-6} kg/mg
- CF2 = conversion factor, yr/365 days
- AT = averaging time for noncarcinogenic effects (6 years as child)

A.3.4 Noncancer Hazard

The algorithm for determining hazard index via all exposure pathways is:

$$HI = Dose / RfD_i \text{ or } RfD_o$$

where

- HI = hazard index
- Dose = the intake dose (mg/kg/day)
- RfD_i or RfD_o = substance-specific reference inhalation or oral dose, mg/kg/day

PUBLIC HEALTH APPENDIX B: HEALTH RISK ASSESSMENT RESULTS

B.1 Risk Assessment Results for the Cancer PMI Receptor

Risk assessment results for the cancer PMI are presented in the tables below:

Public Health Table B.1-1	Average Annual GLC and Soil Concentration at the Cancer PMI
Public Health Table B.1-2	Determination of Cancer Risk at the Cancer PMI
Public Health Table B.1.3	Determination of Noncancer Chronic Hazard Index at the Cancer PMI
Public Health Table B.1.4	1-Hour GLC and Determination of Acute Hazard Index at the Cancer PMI

Public Health Table B.1-1 Average Annual GLC and Soil Concentration at the Cancer PMI

	Average Annual Ground Level Concentration (ug/m3)									
Sources:	HRSG Stack	Coal Dryer	CO2 Vent	GAS FUG (3 sources)	SHIFT (2 sources)	AGR FUG	SRU FUG (2 sources)	SWS FUG	Total GLC	Soil Conc.
Avg annual Chi/Q:	8.1E-02	1.8E-01	1.5E-01	3.2E-01	1.4E+00	1.5E+00	1.7E+00	1.7E+00	ug/m3	mg/kg
Acetaldehyde	8.4E-06	3.3E-06							1.2E-05	
Antimony	5.1E-06	2.0E-06							7.2E-06	3.0E-02
Arsenic	1.1E-05	4.4E-06							1.6E-05	6.5E-02
B[a]anthracene	1.1E-08	4.2E-09							1.5E-08	2.9E-06
Benzene	1.1E-05	4.4E-06							1.6E-05	
Beryllium	1.2E-06	4.8E-07							1.7E-06	7.0E-03
Cadmium	4.5E-05	1.8E-05							6.3E-05	2.6E-01
Chromium	2.4E-06	9.4E-07							3.3E-06	1.4E-02
Cobalt	1.2E-06	4.8E-07							1.7E-06	7.0E-03
Cr(VI)	7.1E-07	2.8E-07							1.0E-06	4.1E-03
Carbonyl Sulfide			2.2E-03	2.6E-04					2.5E-03	
CS2	2.2E-04	8.5E-05							3.0E-04	
Cyanide cmpds	2.7E-05	1.1E-05							3.7E-05	
Formaldehyde	8.0E-05	3.1E-05							1.1E-04	
H2S			1.3E-03	1.9E-03	1.7E-03	9.0E-03	1.3E-03	1.2E-03	1.6E-02	
HCl	6.1E-05	2.4E-05							8.5E-05	
HCN								1.7E-05	1.7E-05	
HF	2.3E-04	9.2E-05							3.2E-04	
Lead	2.6E-06	1.0E-06							3.7E-06	1.5E-02
Manganese	4.9E-06	1.9E-06							6.8E-06	2.8E-02
Mercury	9.5E-07	2.2E-06							3.1E-06	1.3E-02
Methanol			2.0E-03			6.6E-02			6.8E-02	
Methyl Bromide	2.2E-04	8.8E-05							3.1E-04	
Methylene Chlor	1.0E-05	4.1E-06							1.4E-05	
Naphthalene	1.2E-05	4.6E-06							1.6E-05	3.2E-03
NH3	3.6E-02	1.4E-02		6.1E-04	9.3E-03			3.0E-02	9.0E-02	
Nickel	1.8E-06	7.2E-07							2.5E-06	1.1E-02
Phenol	1.7E-04	6.8E-05							2.4E-04	
Propylene						8.1E-02			8.1E-02	
Selenium	2.6E-06	1.0E-06							3.7E-06	1.5E-02
Sulfuric Acid	4.4E-04	1.8E-04							6.2E-04	
Toluene	1.5E-07	6.1E-08							2.2E-07	

Public Health Table B.1-2. Determination of Cancer Risk at the Cancer PMI

Substance	Cancer Risk												
	Inhalation				Soil Ingestion				Dermal Absorption				TOTAL RISK
age range Substance	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	
Acetaldehyde	1.5E-12	3.5E-11	5.0E-11	7.5E-12	-	-	-	-	-	-	-	-	9.4E-11
Antimony	-	-	-	-	-	-	-	-	-	-	-	-	-
Arsenic	2.3E-09	5.6E-08	8.1E-08	1.2E-08	1.0E-08	1.1E-06	5.6E-07	5.6E-08	1.5E-09	2.0E-08	8.1E-08	8.3E-09	2.0E-06
B[a]anthracene	7.2E-14	1.7E-12	2.5E-12	3.8E-13	3.6E-13	3.9E-11	2.0E-11	2.0E-12	1.2E-13	1.5E-12	6.4E-12	6.5E-13	7.5E-11
Benzene	1.9E-11	4.7E-10	6.7E-10	1.0E-10	-	-	-	-	-	-	-	-	1.3E-09
Beryllium	1.8E-10	4.3E-09	6.1E-09	9.1E-10	-	-	-	-	-	-	-	-	1.1E-08
Cadmium	1.2E-08	2.8E-07	4.0E-07	6.0E-08	-	-	-	-	-	-	-	-	7.6E-07
Chromium	-	-	-	-	-	-	-	-	-	-	-	-	-
Cobalt	-	-	-	-	-	-	-	-	-	-	-	-	-
Cr(VI)	6.3E-09	1.5E-07	2.2E-07	3.3E-08	-	-	-	-	-	-	-	-	4.1E-07
Carbonyl Sulfide	-	-	-	-	-	-	-	-	-	-	-	-	-
CS2	-	-	-	-	-	-	-	-	-	-	-	-	-
Cyanide cmpds	-	-	-	-	-	-	-	-	-	-	-	-	-
Formaldehyde	2.9E-11	7.0E-10	1.0E-09	1.5E-10	-	-	-	-	-	-	-	-	1.9E-09
H2S	-	-	-	-	-	-	-	-	-	-	-	-	-
HCl	-	-	-	-	-	-	-	-	-	-	-	-	-
HCN	-	-	-	-	-	-	-	-	-	-	-	-	-
HF	-	-	-	-	-	-	-	-	-	-	-	-	-
Lead	1.9E-12	4.6E-11	6.6E-11	9.9E-12	1.3E-11	1.4E-09	7.4E-10	7.4E-11	3.3E-13	4.3E-12	1.8E-11	1.8E-12	2.4E-09
Manganese	-	-	-	-	-	-	-	-	-	-	-	-	-
Mercury	-	-	-	-	-	-	-	-	-	-	-	-	-
Methanol	-	-	-	-	-	-	-	-	-	-	-	-	-
Methyl Bromide	-	-	-	-	-	-	-	-	-	-	-	-	-
Methylene Chlor	6.2E-13	1.5E-11	2.2E-11	3.2E-12	-	-	-	-	-	-	-	-	4.0E-11
Naphthalene	2.4E-11	5.8E-10	8.4E-10	1.3E-10	-	-	-	-	-	-	-	-	1.6E-09
NH3	-	-	-	-	-	-	-	-	-	-	-	-	-
Nickel	2.9E-11	6.9E-10	9.9E-10	1.5E-10	-	-	-	-	-	-	-	-	1.9E-09
Phenol	-	-	-	-	-	-	-	-	-	-	-	-	-

Public Health Table B.1-2. Determination of Cancer Risk at the Cancer PMI (continued)

Substance	Cancer Risk												
	Inhalation				Soil Ingestion				Dermal Absorption				TOTAL RISK
age range Substance	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	
Propylene	-	-	-	-	-	-	-	-	-	-	-	-	-
Selenium	-	-	-	-	-	-	-	-	-	-	-	-	-
Sulfuric Acid	-	-	-	-	-	-	-	-	-	-	-	-	-
Toluene	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Risk	2.1E-08	5.0E-07	7.1E-07	1.1E-07	1.0E-08	1.1E-06	5.6E-07	5.6E-08	1.5E-09	2.0E-08	8.2E-08	8.3E-09	3.1E-06
Total by pathway				1.3E-06				1.7E-06				1.1E-07	3.1E-06

Public Health Table B.1-3.
Determination of Noncancer Chronic Hazard Index at the Cancer PMI

		Intake (mg/kg/day)			Hazard Index		
	Inhalation	Soil Ing	Dermal Abs	Inhalation	Soil Ing	Dermal Abs	Total HI
Acetaldehyde	1.2E-08			3.1E-07			3.1E-07
Antimony	7.5E-09	1.1E-06	6.9E-09	1.9E-05	2.8E-03	1.7E-05	2.9E-03
Arsenic	1.6E-08	2.5E-06	9.1E-08	3.8E-03	7.1E-01	2.6E-02	7.4E-01
B[a]anthracene	1.6E-11	1.1E-10	8.9E-12	6.1E-09	4.4E-08	3.5E-09	5.3E-08
Benzene	1.6E-08			9.5E-07			9.5E-07
Beryllium	1.8E-09	2.7E-07	1.6E-09	8.9E-04	1.3E-04	8.2E-07	1.0E-03
Cadmium	6.5E-08	9.9E-06	6.0E-09	1.1E-02	2.0E-02	1.2E-05	3.1E-02
Chromium	3.5E-09	5.3E-07	3.2E-09	1.7E-07	2.6E-05	1.6E-07	2.7E-05
Cobalt	1.8E-09	2.7E-07	1.6E-09	1.0E-03	9.0E-04	5.4E-06	1.9E-03
Cr(VI)	1.0E-09	1.6E-07	9.6E-10	1.8E-05	7.9E-06	4.8E-08	2.6E-05
Carbonyl Sulfide	2.6E-06			9.1E-04			9.1E-04
CS2	3.1E-07			1.4E-06			1.4E-06
Cyanide cmpds	3.9E-08			1.5E-05			1.5E-05
Formaldehyde	1.2E-07			4.5E-05			4.5E-05
H2S	1.7E-05			6.0E-03			6.0E-03
HCl	8.9E-08			3.4E-05			3.4E-05
HCN	1.8E-08			7.0E-06			7.0E-06
HF	3.4E-07			8.5E-05			8.5E-05
Lead	3.8E-09	5.8E-07	3.5E-09	-	-	-	
Manganese	7.1E-09	1.1E-06	6.5E-09	2.8E-04	4.2E-02	2.5E-04	4.2E-02
Mercury	3.3E-09	5.0E-07	3.0E-09	3.8E-04	3.1E-03	1.9E-05	3.5E-03
Methanol	7.1E-05			6.2E-05			6.2E-05
Methyl Bromide	3.3E-07			2.3E-04			2.3E-04
Methylene Chlor	1.5E-08			1.3E-07			1.3E-07
Naphthalene	1.7E-08	1.2E-07	9.7E-09	6.6E-06	4.8E-05	3.8E-06	5.8E-05
NH3	9.4E-05			1.6E-03			1.6E-03
Nickel	2.7E-09	4.0E-07	2.5E-09	6.6E-04	3.7E-05	2.2E-07	7.0E-04
Phenol	2.5E-07			4.4E-06			4.4E-06
Propylene	8.5E-05			9.9E-05			9.9E-05
Selenium	3.8E-09	5.8E-07	3.5E-09	6.7E-07	1.0E-04	6.2E-07	1.0E-04
Sulfuric Acid	6.5E-07			2.3E-03			2.3E-03
Toluene	2.2E-10			2.6E-09			2.6E-09
Total Hazard Index				0.030	0.78	0.026	0.84

Public Health Table B.1-4. 1-Hour GLC and Determination of Acute Hazard Index at the Cancer PMI

	1-Hour Ground Level Concentration (ug/m3)									
Sources:	HRSG Stack	Coal Dryer	CO2 Vent	GAS FUG (3 sources)	SHIFT (2 sources)	AGR FUG	SRU FUG (2 sources)	SWS FUG	Total GLC	Hazard Index
1-Hour Chi/Q:	4.5E+00	7.0E+00	9.6E+00	2.2E+01	2.7E+02	3.1E+02	3.0E+02	3.12E+02		
Acetaldehyde	2.5E-03	6.8E-04							3.2E-03	6.7E-06
Antimony	1.5E-03	4.2E-04							1.9E-03	
Arsenic	3.3E-03	9.1E-04							4.2E-03	2.1E-02
B[a]anthracene	3.2E-06	8.7E-07							4.0E-06	
Benzene	3.3E-03	9.1E-04							4.2E-03	3.3E-06
Beryllium	3.6E-04	9.9E-05							4.6E-04	
Cadmium	1.3E-02	3.6E-03							1.7E-02	
Chromium	7.1E-04	1.9E-04							9.0E-04	
Cobalt	3.6E-04	9.9E-05							4.6E-04	
Cr(VI)	2.1E-04	5.8E-05							2.7E-04	
Carbonyl Sulfide			1.3E+01	8.5E-02					1.3E+01	3.1E-01
CS2	6.4E-02	1.7E-02							8.1E-02	1.3E-05
Cyanide cmpds	7.9E-03	2.2E-03							1.0E-02	3.0E-05
Formaldehyde	2.3E-02	6.4E-03							3.0E-02	5.4E-04
H2S			7.2E+00	6.3E-01	1.6E+00	9.0E+00	1.2E+00	1.1E+00	2.1E+01	5.0E-01
HCl	1.8E-02	4.9E-03							2.3E-02	1.1E-05
HCN								5.1E-03	5.1E-03	1.5E-05
HF	6.9E-02	1.9E-02							8.8E-02	3.7E-04
Lead	7.7E-04	2.1E-04							9.8E-04	
Manganese	1.4E-03	3.9E-04							1.8E-03	
Mercury	2.8E-04	4.6E-04							7.4E-04	1.2E-03
Methanol			2.7E+01			6.1E+01			8.8E+01	3.1E-03
Methyl Bromide	6.6E-02	1.8E-02							8.4E-02	2.2E-05
Methylene Chlor	3.0E-03	8.3E-04							3.9E-03	2.8E-07
Naphthalene	3.5E-03	9.4E-04							4.4E-03	
NH3	1.1E+01	2.8E+00		2.2E-01	8.6E+00			2.7E+01	4.9E+01	1.5E-02
Nickel	5.4E-04	1.5E-04							6.9E-04	3.4E-03
Phenol	5.1E-02	1.4E-02							6.5E-02	1.1E-05
Propylene						8.2E+01			8.2E+01	
Selenium	7.7E-04	2.1E-04							9.8E-04	

Public Health Table B.1-4. 1-Hour GLC and Determination of Acute Hazard Index at the Cancer PMI (continued)

	1-Hour Ground Level Concentration (ug/m3)									
Sources:	HRSG Stack	Coal Dryer	CO2 Vent	GAS FUG (3 sources)	SHIFT (2 sources)	AGR FUG	SRU FUG (2 sources)	SWS FUG	Total GLC	Hazard Index
1-Hour Chi/Q:	4.5E+00	7.0E+00	9.6E+00	2.2E+01	2.7E+02	3.1E+02	3.0E+02	3.12E+02		
Sulfuric Acid	1.3E-01	3.6E-02							1.7E-01	1.4E-03
Toluene	4.6E-05	1.3E-05							5.8E-05	1.6E-09
Total Hazard Index										0.85

B.2 Risk Assessment Results for the Noncancer PMI Receptor

Risk assessment results for the noncancer PMI are presented in the tables below:

Public Health Table B.2-1	Average Annual GLC and Soil Concentration at the Noncancer PMI
Public Health Table B.2-2	Determination of Cancer Risk at the Noncancer PMI
Public Health Table B.2.3	Determination of Noncancer Chronic Hazard Index at the Noncancer PMI
Public Health Table B.2.4	1-Hour GLC and Determination of Acute Hazard Index at the Noncancer PMI

Public Health Table B.2-1
Average Annual GLC and Soil Concentration at the Noncancer PMI

	Average Annual Ground Level Concentration (ug/m3)									
Sources:	HRSG Stack	Coal Dryer	CO2 Vent	GAS FUG (3 sources)	SHIFT (2 sources)	AGR FUG	SRU FUG (2 sources)	SWS FUG	Total GLC	Soil Conc.
Avg annual Chi/Q:	9.6E-02	2.0E-01	1.2E-01	3.7E-01	1.8E+00	1.7E+00	1.6E+00	1.6E+00		
Acetaldehyde	1.0E-05	3.6E-06							1.4E-05	
Antimony	6.1E-06	2.2E-06							8.3E-06	3.4E-02
Arsenic	1.3E-05	4.8E-06							1.8E-05	7.5E-02
B[a]anthracene	1.3E-08	4.6E-09							1.7E-08	3.4E-06
Benzene	1.3E-05	4.8E-06							1.8E-05	
Beryllium	1.4E-06	5.2E-07							2.0E-06	8.1E-03
Cadmium	5.4E-05	1.9E-05							7.3E-05	3.0E-01
Chromium	2.8E-06	1.0E-06							3.8E-06	1.6E-02
Cobalt	1.4E-06	5.2E-07							2.0E-06	8.1E-03
Cr(VI)	8.5E-07	3.1E-07							1.2E-06	4.8E-03
Carbonyl Sulfide			1.9E-03	3.0E-04					2.2E-03	
CS2	2.6E-04	9.2E-05							3.5E-04	
Cyanide cmpds	3.2E-05	1.1E-05							4.3E-05	
Formaldehyde	9.5E-05	3.4E-05							1.3E-04	
H2S			1.1E-03	2.1E-03	2.1E-03	9.8E-03	1.3E-03	1.2E-03	1.8E-02	
HCl	7.2E-05	2.6E-05							9.8E-05	
HCN								1.6E-05	1.6E-05	
HF	2.8E-04	9.9E-05							3.8E-04	
Lead	3.1E-06	1.1E-06							4.3E-06	1.8E-02
Manganese	5.8E-06	2.1E-06							7.9E-06	3.3E-02
Mercury	1.1E-06	2.3E-06							3.5E-06	1.4E-02
Methanol			1.7E-03			7.2E-02			7.4E-02	
Methyl Bromide	2.7E-04	9.5E-05							3.6E-04	
Methylene Chlor	1.2E-05	4.4E-06							1.7E-05	
Naphthalene	1.4E-05	5.0E-06							1.9E-05	3.7E-03
NH3	4.3E-02	1.5E-02		7.0E-04	1.1E-02			2.8E-02	9.8E-02	
Nickel	2.2E-06	7.8E-07							2.9E-06	1.2E-02
Phenol	2.1E-04	7.4E-05							2.8E-04	
Propylene						8.9E-02			8.9E-02	
Selenium	3.1E-06	1.1E-06							4.3E-06	1.8E-02
Sulfuric Acid	5.3E-04	1.9E-04							7.2E-04	
Toluene	1.8E-07	6.6E-08							2.5E-07	

Public Health Table B.2-2. Determination of Cancer Risk at the Noncancer PMI

	Cancer Risk												
Substance	Inhalation				Soil Ingestion				Dermal Absorption				TOTAL RISK
age range	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	
Substance													
Acetaldehyde	1.7E-12	4.1E-11	5.8E-11	8.8E-12	-	-	-	-	-	-	-	-	1.1E-10
Antimony	-	-	-	-	-	-	-	-	-	-	-	-	-
Arsenic	2.7E-09	6.5E-08	9.3E-08	1.4E-08	1.2E-08	1.2E-06	6.5E-07	6.5E-08	1.7E-09	2.3E-08	9.4E-08	9.6E-09	2.3E-06
B[a]anthracene	8.4E-14	2.0E-12	2.9E-12	4.4E-13	4.2E-13	4.5E-11	2.4E-11	2.4E-12	1.4E-13	1.8E-12	7.4E-12	7.6E-13	8.7E-11
Benzene	2.2E-11	5.4E-10	7.8E-10	1.2E-10	-	-	-	-	-	-	-	-	1.5E-09
Beryllium	2.0E-10	4.9E-09	7.1E-09	1.1E-09	-	-	-	-	-	-	-	-	1.3E-08
Cadmium	1.3E-08	3.3E-07	4.7E-07	7.0E-08	-	-	-	-	-	-	-	-	8.8E-07
Chromium	-	-	-	-	-	-	-	-	-	-	-	-	-
Cobalt	-	-	-	-	-	-	-	-	-	-	-	-	-
Cr(VI)	7.3E-09	1.8E-07	2.5E-07	3.8E-08	-	-	-	-	-	-	-	-	4.7E-07
Carbonyl Sulfide	-	-	-	-	-	-	-	-	-	-	-	-	-
CS2	-	-	-	-	-	-	-	-	-	-	-	-	-
Cyanide cmpds	-	-	-	-	-	-	-	-	-	-	-	-	-
Formaldehyde	3.3E-11	8.1E-10	1.2E-09	1.7E-10	-	-	-	-	-	-	-	-	2.2E-09
H2S	-	-	-	-	-	-	-	-	-	-	-	-	-
HCl	-	-	-	-	-	-	-	-	-	-	-	-	-
HCN	-	-	-	-	-	-	-	-	-	-	-	-	-
HF	-	-	-	-	-	-	-	-	-	-	-	-	-
Lead	2.2E-12	5.3E-11	7.7E-11	1.1E-11	1.5E-11	1.6E-09	8.6E-10	8.6E-11	3.8E-13	5.0E-12	2.1E-11	2.1E-12	2.8E-09
Manganese	-	-	-	-	-	-	-	-	-	-	-	-	-
Mercury	-	-	-	-	-	-	-	-	-	-	-	-	-
Methanol	-	-	-	-	-	-	-	-	-	-	-	-	-
Methyl Bromide	-	-	-	-	-	-	-	-	-	-	-	-	-
Methylene Chlor	7.2E-13	1.7E-11	2.5E-11	3.7E-12	-	-	-	-	-	-	-	-	4.7E-11

Public Table Table B.2-2. Determination of Cancer Risk at the Noncancer PMI (continued)

	Cancer Risk												
Substance	Inhalation				Soil Ingestion				Dermal Absorption				TOTAL RISK
age range	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	
Substance													
Naphthalene	2.8E-11	6.8E-10	9.7E-10	1.5E-10									1.8E-09
NH3	-	-	-	-									-
Nickel	3.3E-11	8.0E-10	1.2E-09	1.7E-10									2.2E-09
Phenol													-
Propylene	-	-	-	-	-	-	-	-	-	-	-	-	-
Selenium	-	-	-	-	-	-	-	-	-	-	-	-	-
Sulfuric Acid	-	-	-	-	-	-	-	-	-	-	-	-	-
Toluene	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Risk	2.4E-08	5.7E-07	8.2E-07	1.2E-07	1.2E-08	1.2E-06	6.5E-07	6.5E-08	1.7E-09	2.3E-08	9.5E-08	9.6E-09	3.6E-06
Total by pathway				1.5E-06				2.0E-06				1.3E-07	3.6E-06

Public Health Table B.2-3.
Determination of Noncancer Chronic Hazard Index at the Noncancer PMI

		Intake (mg/kg/day)			Hazard Index		
	Inhalation	Soil Ing	Dermal Abs	Inhalation	Soil Ing	Dermal Abs	Total HI
Acetaldehyde	1.4E-08			3.6E-07			3.6E-07
Antimony	8.7E-09	1.3E-06	8.0E-09	2.2E-05	3.3E-03	2.0E-05	3.3E-03
Arsenic	1.9E-08	2.9E-06	1.0E-07	4.4E-03	8.2E-01	3.0E-02	8.6E-01
B[a]anthracene	1.8E-11	1.3E-10	1.0E-11	7.1E-09	5.1E-08	4.0E-09	6.2E-08
Benzene	1.9E-08			1.1E-06			1.1E-06
Beryllium	2.1E-09	3.1E-07	1.9E-09	1.0E-03	1.6E-04	9.5E-07	1.2E-03
Cadmium	7.6E-08	1.2E-05	7.0E-09	1.3E-02	2.3E-02	1.4E-05	3.6E-02
Chromium	4.0E-09	6.1E-07	3.7E-09	2.0E-07	3.1E-05	1.9E-07	3.1E-05
Cobalt	2.1E-09	3.1E-07	1.9E-09	1.2E-03	1.0E-03	6.3E-06	2.2E-03
Cr(VI)	1.2E-09	1.8E-07	1.1E-09	2.1E-05	9.2E-06	5.6E-08	3.0E-05
Carbonyl Sulfide	2.3E-06			8.1E-04			8.1E-04
CS2	3.6E-07			1.6E-06			1.6E-06
Cyanide cmpds	4.5E-08			1.8E-05			1.8E-05
Formaldehyde	1.3E-07			5.2E-05			5.2E-05
H2S	1.8E-05			6.4E-03			6.4E-03
HCl	1.0E-07			4.0E-05			4.0E-05
HCN	1.7E-08			6.6E-06			6.6E-06
HF	3.9E-07			9.8E-05			9.8E-05
Lead	4.4E-09	6.8E-07	4.1E-09	-	-	-	-
Manganese	8.2E-09	1.2E-06	7.6E-09	3.2E-04	4.9E-02	3.0E-04	4.9E-02
Mercury	3.6E-09	5.5E-07	3.4E-09	4.2E-04	3.5E-03	2.1E-05	3.9E-03
Methanol	7.7E-05			6.7E-05			6.7E-05
Methyl Bromide	3.8E-07			2.6E-04			2.6E-04
Methylene Chlor	1.7E-08			1.5E-07			1.5E-07
Naphthalene	2.0E-08	1.4E-07	1.1E-08	7.7E-06	5.5E-05	4.4E-06	6.7E-05
NH3	1.0E-04			1.8E-03			1.8E-03
Nickel	3.1E-09	4.7E-07	2.8E-09	7.7E-04	4.3E-05	2.6E-07	8.1E-04
Phenol	2.9E-07			5.1E-06			5.1E-06
Propylene	9.3E-05			1.1E-04			1.1E-04
Selenium	4.4E-09	6.8E-07	4.1E-09	7.8E-07	1.2E-04	7.2E-07	1.2E-04
Sulfuric Acid	7.5E-07			2.6E-03			2.6E-03
Toluene	2.6E-10			3.0E-09			3.0E-09
Total Hazard Index				0.034	0.90	0.030	0.97

Public Health Table B.2-4.
1-Hour GLC and Determination of Acute Hazard Index at the Noncancer PMI

	1-Hour Ground Level Concentration (ug/m3)									
Sources:	HRSG Stack	Coal Dryer	CO2 Vent	GAS FUG (3 sources)	SHIFT (2 sources)	AGR FUG	SRU FUG (2 sources)	SWS FUG	Total GLC	Hazard Index
1-Hour Chi/Q:	4.5E+00	7.0E+00	9.6E+00	2.2E+01	2.7E+02	3.1E+02	3.0E+02	3.12E+02		
Acetaldehyde	2.5E-03	6.8E-04							3.2E-03	6.7E-06
Antimony	1.5E-03	4.2E-04							1.9E-03	
Arsenic	3.3E-03	9.1E-04							4.2E-03	2.1E-02
B[a]anthracene	3.2E-06	8.7E-07							4.0E-06	
Benzene	3.3E-03	9.1E-04							4.2E-03	3.3E-06
Beryllium	3.6E-04	9.9E-05							4.6E-04	
Cadmium	1.3E-02	3.6E-03							1.7E-02	
Chromium	7.1E-04	1.9E-04							9.0E-04	
Cobalt	3.6E-04	9.9E-05							4.6E-04	
Cr(VI)	2.1E-04	5.8E-05							2.7E-04	
Carbonyl Sulfide			1.3E+01	2.6E-01					1.3E+01	3.1E-01
CS2	6.4E-02	1.7E-02							8.1E-02	1.3E-05
Cyanide cmpds	7.9E-03	2.2E-03							1.0E-02	3.0E-05
Formaldehyde	2.3E-02	6.4E-03							3.0E-02	5.4E-04
H2S			7.2E+00	1.9E+00	3.3E+00	9.0E+00	2.4E+00	1.1E+00	2.5E+01	5.9E-01
HCl	1.8E-02	4.9E-03							2.3E-02	1.1E-05
HCN								5.1E-03	5.1E-03	1.5E-05
HF	6.9E-02	1.9E-02							8.8E-02	3.7E-04
Lead	7.7E-04	2.1E-04							9.8E-04	
Manganese	1.4E-03	3.9E-04							1.8E-03	
Mercury	2.8E-04	4.6E-04							7.4E-04	1.2E-03
Methanol			2.7E+01			6.1E+01			8.8E+01	3.1E-03
Methyl Bromide	6.6E-02	1.8E-02							8.4E-02	2.2E-05
Methylene Chlor	3.0E-03	8.3E-04							3.9E-03	2.8E-07
Naphthalene	3.5E-03	9.4E-04							4.4E-03	
NH3	1.1E+01	2.8E+00		6.6E-01	1.7E+01			2.7E+01	5.8E+01	1.8E-02
Nickel	5.4E-04	1.5E-04							6.9E-04	3.4E-03
Phenol	5.1E-02	1.4E-02							6.5E-02	1.1E-05
Propylene						8.2E+01			8.2E+01	
Selenium	7.7E-04	2.1E-04							9.8E-04	

Public Health Table B.2-4.
1-Hour GLC and Determination of Acute Hazard Index at the Noncancer PMI (continued)

	1-Hour Ground Level Concentration (ug/m3)									
Sources:	HRSG Stack	Coal Dryer	CO2 Vent	GAS FUG (3 sources)	SHIFT (2 sources)	AGR FUG	SRU FUG (2 sources)	SWS FUG	Total GLC	Hazard Index
1-Hour Chi/Q:	4.5E+00	7.0E+00	9.6E+00	2.2E+01	2.7E+02	3.1E+02	3.0E+02	3.12E+02		
Sulfuric Acid	1.3E-01	3.6E-02							1.7E-01	1.4E-03
Toluene	4.6E-05	1.3E-05							5.8E-05	1.6E-09
Total Hazard Index										0.95

B.3 Risk Assessment Results for the Acute PMI Receptor

Risk assessment results for the acute PMI are presented in the tables below:

Public Health Table B.3-1
Average Annual GLC and Soil Concentration at the Acute PMI

	Average Annual Ground Level Concentration (ug/m3)									
Sources:	HRSG Stack	Coal Dryer	CO2 Vent	GAS FUG (3 sources)	SHIFT (2 sources)	AGR FUG	SRU FUG (2 sources)	SWS FUG	Total GLC	Soil Conc.
Avg annual Chi/Q:	2.0E-03	5.0E-02	3.6E-02	6.8E-01	5.3E+00	7.4E+00	1.5E+01	1.2E+01		
Acetaldehyde	2.1E-07	9.2E-07							1.1E-06	
Antimony	1.3E-07	5.6E-07							6.9E-07	2.8E-03
Arsenic	2.7E-07	1.2E-06							1.5E-06	6.2E-03
B[a]anthracene	2.6E-10	1.2E-09							1.4E-09	2.8E-07
Benzene	2.7E-07	1.2E-06							1.5E-06	
Beryllium	3.0E-08	1.3E-07							1.6E-07	6.7E-04
Cadmium	1.1E-06	4.9E-06							6.0E-06	2.5E-02
Chromium	5.8E-08	2.6E-07							3.2E-07	1.3E-03
Cobalt	3.0E-08	1.3E-07							1.6E-07	6.7E-04
Cr(VI)	1.7E-08	7.8E-08							9.6E-08	4.0E-04
Carbonyl Sulfide			5.5E-04	5.5E-04					1.1E-03	
CS2	5.2E-06	2.4E-05							2.9E-05	
Cyanide cmpds	6.5E-07	2.9E-06							3.6E-06	
Formaldehyde	1.9E-06	8.7E-06							1.1E-05	
H2S			3.1E-04	3.9E-03	6.3E-03	4.3E-02	1.2E-02	9.0E-03	7.5E-02	
HCl	1.5E-06	6.7E-06							8.1E-06	
HCN								1.2E-04	1.2E-04	
HF	5.7E-06	2.6E-05							3.1E-05	
Lead	6.4E-08	2.9E-07							3.5E-07	1.5E-03
Manganese	1.2E-07	5.3E-07							6.5E-07	2.7E-03
Mercury	2.3E-08	6.0E-07							6.3E-07	2.6E-03
Methanol			5.0E-04			3.2E-01			3.2E-01	
Methyl Bromide	5.4E-06	2.4E-05							3.0E-05	
Methylene Chlor	2.5E-07	1.1E-06							1.4E-06	
Naphthalene	2.8E-07	1.3E-06							1.6E-06	3.1E-04
NH3	8.7E-04	3.9E-03		1.3E-03	3.4E-02			2.2E-01	2.6E-01	
Nickel	4.4E-08	2.0E-07							2.4E-07	1.0E-03
Phenol	4.2E-06	1.9E-05							2.3E-05	
Propylene						3.9E-01			3.9E-01	
Selenium	6.4E-08	2.9E-07							3.5E-07	1.5E-03
Sulfuric Acid	1.1E-05	4.9E-05							5.9E-05	
Toluene	3.8E-09	1.7E-08							2.1E-08	

Public Health Table B.3-2.
Determination of Cancer Risk at the Acute PMI

	Cancer Risk												
Substance	Inhalation				Soil Ingestion				Dermal Absorption				TOTAL RISK
age range	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	
Substance													
Acetaldehyde	1.4E-13	3.4E-12	4.8E-12	7.2E-13	-	-	-	-	-	-	-	-	9.0E-12
Antimony	-	-	-	-	-	-	-	-	-	-	-	-	-
Arsenic	2.2E-10	5.4E-09	7.7E-09	1.2E-09	9.6E-10	1.0E-07	5.4E-08	5.4E-09	1.4E-10	1.9E-09	7.8E-09	8.0E-10	1.9E-07
B[a]anthracene	6.9E-15	1.7E-13	2.4E-13	3.6E-14	3.5E-14	3.7E-12	1.9E-12	1.9E-13	1.1E-14	1.5E-13	6.2E-13	6.3E-14	7.2E-12
Benzene	1.9E-12	4.5E-11	6.4E-11	9.6E-12	-	-	-	-	-	-	-	-	1.2E-10
Beryllium	1.7E-11	4.1E-10	5.9E-10	8.8E-11	-	-	-	-	-	-	-	-	1.1E-09
Cadmium	1.1E-09	2.7E-08	3.9E-08	5.8E-09	-	-	-	-	-	-	-	-	7.2E-08
Chromium	-	-	-	-	-	-	-	-	-	-	-	-	-
Cobalt	-	-	-	-	-	-	-	-	-	-	-	-	-
Cr(VI)	6.0E-10	1.5E-08	2.1E-08	3.1E-09	-	-	-	-	-	-	-	-	3.9E-08
Carbonyl Sulfide	-	-	-	-	-	-	-	-	-	-	-	-	-
CS2	-	-	-	-	-	-	-	-	-	-	-	-	-
Cyanide cmpds	-	-	-	-	-	-	-	-	-	-	-	-	-
Formaldehyde	2.8E-12	6.7E-11	9.6E-11	1.4E-11	-	-	-	-	-	-	-	-	1.8E-10
H2S	-	-	-	-	-	-	-	-	-	-	-	-	-
HCl	-	-	-	-	-	-	-	-	-	-	-	-	-
HCN	-	-	-	-	-	-	-	-	-	-	-	-	-
HF	-	-	-	-	-	-	-	-	-	-	-	-	-
Lead	1.8E-13	4.4E-12	6.3E-12	9.5E-13	1.3E-12	1.4E-10	7.1E-11	7.1E-12	3.1E-14	4.2E-13	1.7E-12	1.8E-13	2.3E-10
Manganese	-	-	-	-	-	-	-	-	-	-	-	-	-
Mercury	-	-	-	-	-	-	-	-	-	-	-	-	-
Methanol	-	-	-	-	-	-	-	-	-	-	-	-	-
Methyl Bromide	-	-	-	-	-	-	-	-	-	-	-	-	-
Methylene Chlor	6.0E-14	1.4E-12	2.1E-12	3.1E-13	-	-	-	-	-	-	-	-	3.9E-12
Naphthalene	2.3E-12	5.6E-11	8.0E-11	1.2E-11	-	-	-	-	-	-	-	-	1.5E-10
NH3	-	-	-	-	-	-	-	-	-	-	-	-	-
Nickel	2.7E-12	6.6E-11	9.5E-11	1.4E-11	-	-	-	-	-	-	-	-	1.8E-10
Phenol	-	-	-	-	-	-	-	-	-	-	-	-	-

Public Health Table B.3-2.
Determination of Cancer Risk at the Acute PMI (continued)

	Cancer Risk												
Substance	Inhalation				Soil Ingestion				Dermal Absorption				TOTAL RISK
age range	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	
Substance													
Propylene	-	-	-	-	-	-	-	-	-	-	-	-	-
Selenium	-	-	-	-	-	-	-	-	-	-	-	-	-
Sulfuric Acid	-	-	-	-	-	-	-	-	-	-	-	-	-
Toluene	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Risk	2.0E-09	4.7E-08	6.8E-08	1.0E-08	9.6E-10	1.0E-07	5.4E-08	5.4E-09	1.4E-10	1.9E-09	7.8E-09	8.0E-10	3.0E-07
Total by pathway				1.3E-07				1.6E-07				1.1E-08	3.0E-07

Public Health Table B.3-3.
Determination of Noncancer Chronic Hazard Index at the Acute PMI

		Intake (mg/kg/day)			Hazard Index		
	Inhalation	Soil Ing	Dermal Abs	Inhalation	Soil Ing	Dermal Abs	Total HI
Acetaldehyde	1.2E-09			2.9E-08			2.9E-08
Antimony	7.2E-10	1.1E-07	6.6E-10	1.8E-06	2.7E-04	1.7E-06	2.8E-04
Arsenic	1.6E-09	2.4E-07	8.7E-09	3.7E-04	6.8E-02	2.5E-03	7.1E-02
B[a]anthracene	1.5E-12	1.1E-11	8.5E-13	5.8E-10	4.2E-09	3.3E-10	5.1E-09
Benzene	1.6E-09			9.2E-08			9.2E-08
Beryllium	1.7E-10	2.6E-08	1.6E-10	8.5E-05	1.3E-05	7.8E-08	9.8E-05
Cadmium	6.3E-09	9.5E-07	5.8E-10	1.1E-03	1.9E-03	1.2E-06	3.0E-03
Chromium	3.3E-10	5.1E-08	3.1E-10	1.7E-08	2.5E-06	1.5E-08	2.6E-06
Cobalt	1.7E-10	2.6E-08	1.6E-10	9.9E-05	8.6E-05	5.2E-07	1.9E-04
Cr(VI)	1.0E-10	1.5E-08	9.2E-11	1.8E-06	7.6E-07	4.6E-09	2.5E-06
Carbonyl Sulfide	1.1E-06			4.0E-04			4.0E-04
CS2	3.0E-08			1.3E-07			1.3E-07
Cyanide cmpds	3.7E-09			1.4E-06			1.4E-06
Formaldehyde	1.1E-08			4.3E-06			4.3E-06
H2S	7.8E-05			2.7E-02			2.7E-02
HCl	8.5E-09			3.3E-06			3.3E-06
HCN	1.3E-07			5.1E-05			5.1E-05
HF	3.3E-08			8.2E-06			8.2E-06
Lead	3.7E-10	5.6E-08	3.4E-10	-	-	-	-
Manganese	6.8E-10	1.0E-07	6.3E-10	2.6E-05	4.0E-03	2.4E-05	4.1E-03
Mercury	6.5E-10	9.9E-08	6.0E-10	7.6E-05	6.2E-04	3.8E-06	7.0E-04
Methanol	3.3E-04			2.9E-04			2.9E-04
Methyl Bromide	3.1E-08			2.2E-05			2.2E-05
Methylene Chlor	1.4E-09			1.3E-08			1.3E-08
Naphthalene	1.6E-09	1.2E-08	9.3E-10	6.4E-07	4.6E-06	3.6E-07	5.6E-06
NH3	2.7E-04			4.7E-03			4.7E-03
Nickel	2.5E-10	3.9E-08	2.3E-10	6.4E-05	3.5E-06	2.1E-08	6.7E-05
Phenol	2.4E-08			4.2E-07			4.2E-07
Propylene	4.1E-04			4.8E-04			4.8E-04
Selenium	3.7E-10	5.6E-08	3.4E-10	6.4E-08	9.8E-06	5.9E-08	9.9E-06
Sulfuric Acid	6.2E-08			2.2E-04			2.2E-04
Toluene	2.2E-11			2.5E-10			2.5E-10
Total Hazard Index				0.035	0.08	0.003	0.11

Public Health Table B.3-4. 1-Hour GLC and Determination of Acute Hazard Index at the Acute PMI

	1-Hour Ground Level Concentration (ug/m3)									
Sources:	HRSG Stack	Coal Dryer	CO2 Vent	GAS FUG (3 sources)	SHIFT (2 sources)	AGR FUG	SRU FUG (2 sources)	SWS FUG	Total GLC	Hazard Index
1-Hour Chi/Q:	3.4E-01	4.0E+00	5.2E+00	5.2E+01	5.2E+02	5.9E+02	7.9E+02	7.7E+02		
Acetaldehyde	1.9E-04	3.9E-04							5.8E-04	1.2E-06
Antimony	1.2E-04	2.4E-04							3.5E-04	
Arsenic	2.5E-04	5.2E-04							7.7E-04	3.9E-03
B[a]anthracene	2.4E-07	5.0E-07							7.4E-07	
Benzene	2.5E-04	5.2E-04							7.7E-04	6.0E-07
Beryllium	2.7E-05	5.7E-05							8.4E-05	
Cadmium	1.0E-03	2.1E-03							3.1E-03	
Chromium	5.4E-05	1.1E-04							1.6E-04	
Cobalt	2.7E-05	5.7E-05							8.4E-05	
Cr(VI)	1.6E-05	3.3E-05							4.9E-05	
Carbonyl Sulfide			6.9E+00	2.0E-01					7.1E+00	1.7E-01
CS2	4.8E-03	1.0E-02							1.5E-02	2.4E-06
Cyanide cmpds	6.0E-04	1.2E-03							1.8E-03	5.4E-06
Formaldehyde	1.8E-03	3.7E-03							5.5E-03	1.0E-04
H2S			3.9E+00	1.5E+00	3.2E+00	1.7E+01	3.2E+00	2.8E+00	3.2E+01	7.5E-01
HCl	1.4E-03	2.8E-03							4.2E-03	2.0E-06
HCN								1.3E-02	1.3E-02	3.8E-05
HF	5.3E-03	1.1E-02							1.6E-02	6.7E-05
Lead	5.9E-05	1.2E-04							1.8E-04	
Manganese	1.1E-04	2.3E-04							3.4E-04	
Mercury	2.1E-05	2.6E-04							2.9E-04	4.8E-04
Methanol			1.5E+01			1.1E+02			1.3E+02	4.6E-03
Methyl Bromide	5.0E-03	1.0E-02							1.5E-02	3.9E-06
Methylene Chlor	2.3E-04	4.8E-04							7.1E-04	5.1E-08
Naphthalene	2.6E-04	5.4E-04							8.0E-04	
NH3	8.0E-01	1.6E+00		5.2E-01	1.7E+01			6.7E+01	8.7E+01	2.7E-02
Nickel	4.1E-05	8.5E-05							1.3E-04	6.3E-04
Phenol	3.9E-03	8.0E-03							1.2E-02	2.0E-06
Propylene						1.5E+02			1.5E+02	
Selenium	5.9E-05	1.2E-04							1.8E-04	

Public Health Table B.3-4. 1-Hour GLC and Determination of Acute Hazard Index at the Acute PMI (continued)

	1-Hour Ground Level Concentration (ug/m3)									
Sources:	HRSG Stack	Coal Dryer	CO2 Vent	GAS FUG (3 sources)	SHIFT (2 sources)	AGR FUG	SRU FUG (2 sources)	SWS FUG	Total GLC	Hazard Index
1-Hour Chi/Q:	4.5E+00	7.0E+00	9.6E+00	2.2E+01	2.7E+02	3.1E+02	3.0E+02	3.12E+02		
Sulfuric Acid	1.0E-02	2.1E-02							3.1E-02	2.6E-04
Toluene	3.5E-06	7.2E-06							1.1E-05	2.9E-10
Total Hazard Index										0.96

B.4 Risk Assessment Results for the Chronic MEIR Receptor

Risk assessment results for the chronic MEIR are presented in the tables below:

PUBLIC HEALTH Table B.4-1 Average Annual GLC and Soil Concentration at the Chronic MEIR

PUBLIC HEALTH Table B.4-2 Determination of Cancer Risk at the Chronic MEIR

PUBLIC HEALTH Table B.4.3 Determination of Noncancer Chronic Hazard Index at the Chronic MEIR

PUBLIC HEALTH Table B.4.4 1-Hour GLC and Determination of Acute Hazard Index at the Chronic MEIR

Public Health Table B.4-1 Average Annual GLC and Soil Concentration at the Chronic MEIR

	Average Annual Ground Level Concentration (ug/m3)									
Sources:	HRSG Stack	Coal Dryer	CO2 Vent	GAS FUG (3 sources)	SHIFT (2 sources)	AGR FUG	SRU FUG (2 sources)	SWS FUG	Total GLC	Soil Conc.
Avg annual Chi/Q:	6.7E-02	1.3E-01	7.2E-02	2.9E-01	1.3E+00	1.2E+00	1.1E+00	1.1E+00		
Acetaldehyde	7.0E-06	2.3E-06							9.3E-06	
Antimony	4.3E-06	1.4E-06							5.7E-06	2.4E-02
Arsenic	9.3E-06	3.1E-06							1.2E-05	5.1E-02
B[a]anthracene	8.9E-09	3.0E-09							1.2E-08	2.3E-06
Benzene	9.3E-06	3.1E-06							1.2E-05	
Beryllium	1.0E-06	3.3E-07							1.3E-06	5.6E-03
Cadmium	3.7E-05	1.2E-05							5.0E-05	2.1E-01
Chromium	2.0E-06	6.6E-07							2.6E-06	1.1E-02
Cobalt	1.0E-06	3.3E-07							1.3E-06	5.6E-03
Cr(VI)	5.9E-07	2.0E-07							7.9E-07	3.3E-03
Carbonyl Sulfide			1.1E-03	2.3E-04					1.3E-03	
CS2	1.8E-04	5.9E-05							2.4E-04	
Cyanide cmpds	2.2E-05	7.3E-06							3.0E-05	
Formaldehyde	6.6E-05	2.2E-05							8.8E-05	
H2S			6.2E-04	1.7E-03	1.5E-03	7.1E-03	8.9E-04	8.2E-04	1.3E-02	
HCl	5.0E-05	1.7E-05							6.7E-05	
HCN								1.1E-05	1.1E-05	
HF	1.9E-04	6.4E-05							2.6E-04	
Lead	2.2E-06	7.2E-07							2.9E-06	1.2E-02
Manganese	4.0E-06	1.3E-06							5.4E-06	2.2E-02
Mercury	7.9E-07	1.5E-06							2.3E-06	9.6E-03
Methanol			1.0E-03			5.2E-02			5.3E-02	
Methyl Bromide	1.9E-04	6.1E-05							2.5E-04	
Methylene Chlor	8.5E-06	2.8E-06							1.1E-05	
Naphthalene	9.7E-06	3.2E-06							1.3E-05	2.5E-03
NH3	3.0E-02	9.9E-03		5.5E-04	8.2E-03			2.0E-02	6.8E-02	
Nickel	1.5E-06	5.0E-07							2.0E-06	8.3E-03
Phenol	1.4E-04	4.8E-05							1.9E-04	
Propylene						6.4E-02			6.4E-02	
Selenium	2.2E-06	7.2E-07							2.9E-06	1.2E-02
Sulfuric Acid	3.7E-04	1.2E-04							4.9E-04	
Toluene	1.3E-07	4.3E-08							1.7E-07	

Public Health Table B.4-2. Determination of Cancer Risk at the Chronic MEIR

	Cancer Risk												
Substance	Inhalation				Soil Ingestion				Dermal Absorption				TOTAL RISK
age range	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	
Substance													
Acetaldehyde	1.2E-12	2.8E-11	4.0E-11	6.0E-12	-	-	-	-	-	-	-	-	7.5E-11
Antimony	-	-	-	-	-	-	-	-	-	-	-	-	-
Arsenic	1.8E-09	4.4E-08	6.4E-08	9.6E-09	7.9E-09	8.4E-07	4.4E-07	4.4E-08	1.2E-09	1.6E-08	6.5E-08	6.6E-09	1.5E-06
B[a]anthracene	5.7E-14	1.4E-12	2.0E-12	3.0E-13	2.9E-13	3.1E-11	1.6E-11	1.6E-12	9.3E-14	1.2E-12	5.1E-12	5.2E-13	5.9E-11
Benzene	1.5E-11	3.7E-10	5.3E-10	8.0E-11	-	-	-	-	-	-	-	-	1.0E-09
Beryllium	1.4E-10	3.4E-09	4.8E-09	7.2E-10	-	-	-	-	-	-	-	-	9.1E-09
Cadmium	9.2E-09	2.2E-07	3.2E-07	4.8E-08	-	-	-	-	-	-	-	-	6.0E-07
Chromium	-	-	-	-	-	-	-	-	-	-	-	-	-
Cobalt	-	-	-	-	-	-	-	-	-	-	-	-	-
Cr(VI)	5.0E-09	1.2E-07	1.7E-07	2.6E-08	-	-	-	-	-	-	-	-	3.2E-07
Carbonyl Sulfide	-	-	-	-	-	-	-	-	-	-	-	-	-
CS2	-	-	-	-	-	-	-	-	-	-	-	-	-
Cyanide cmpds	-	-	-	-	-	-	-	-	-	-	-	-	-
Formaldehyde	2.3E-11	5.5E-10	7.9E-10	1.2E-10	-	-	-	-	-	-	-	-	1.5E-09
H2S	-	-	-	-	-	-	-	-	-	-	-	-	-
HCl	-	-	-	-	-	-	-	-	-	-	-	-	-
HCN	-	-	-	-	-	-	-	-	-	-	-	-	-
HF	-	-	-	-	-	-	-	-	-	-	-	-	-
Lead	1.5E-12	3.6E-11	5.2E-11	7.8E-12	1.1E-11	1.1E-09	5.9E-10	5.9E-11	2.6E-13	3.4E-12	1.4E-11	1.5E-12	1.9E-09
Manganese	-	-	-	-	-	-	-	-	-	-	-	-	-
Mercury	-	-	-	-	-	-	-	-	-	-	-	-	-
Methanol	-	-	-	-	-	-	-	-	-	-	-	-	-
Methyl Bromide	-	-	-	-	-	-	-	-	-	-	-	-	-
Methylene Chlor	4.9E-13	1.2E-11	1.7E-11	2.6E-12	-	-	-	-	-	-	-	-	3.2E-11
Naphthalene	1.9E-11	4.6E-10	6.6E-10	1.0E-10	-	-	-	-	-	-	-	-	1.2E-09
NH3	-	-	-	-	-	-	-	-	-	-	-	-	-
Nickel	2.3E-11	5.5E-10	7.9E-10	1.2E-10	-	-	-	-	-	-	-	-	1.5E-09
Phenol	-	-	-	-	-	-	-	-	-	-	-	-	-

Public Health Table B.4-2. Determination of Cancer Risk at the Chronic MEIR (continued)

	Cancer Risk												
Substance	Inhalation				Soil Ingestion				Dermal Absorption				TOTAL RISK
age range	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	
Substance													
Propylene	-	-	-	-	-	-	-	-	-	-	-	-	-
Selenium	-	-	-	-	-	-	-	-	-	-	-	-	-
Sulfuric Acid	-	-	-	-	-	-	-	-	-	-	-	-	-
Toluene	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Risk	1.6E-08	3.9E-07	5.6E-07	8.4E-08	7.9E-09	8.5E-07	4.4E-07	4.4E-08	1.2E-09	1.6E-08	6.5E-08	6.6E-09	2.5E-06
Total by pathway				1.1E-06				1.3E-06				8.8E-08	2.5E-06

Public Health Table B.4-3.
Determination of Noncancer Chronic Hazard Index at the Chronic MEIR

		Intake (mg/kg/day)			Hazard Index		
	Inhalation	Soil Ing	Dermal Abs	Inhalation	Soil Ing	Dermal Abs	Total HI
Acetaldehyde	9.7E-09			2.4E-07			2.4E-07
Antimony	5.9E-09	9.0E-07	5.5E-09	1.5E-05	2.3E-03	1.4E-05	2.3E-03
Arsenic	1.3E-08	2.0E-06	7.2E-08	3.0E-03	5.6E-01	2.0E-02	5.9E-01
B[a]anthracene	1.2E-11	8.9E-11	7.1E-12	4.8E-09	3.5E-08	2.7E-09	4.2E-08
Benzene	1.3E-08			7.6E-07			7.6E-07
Beryllium	1.4E-09	2.1E-07	1.3E-09	7.0E-04	1.1E-04	6.5E-07	8.1E-04
Cadmium	5.2E-08	7.9E-06	4.8E-09	9.1E-03	1.6E-02	9.6E-06	2.5E-02
Chromium	2.7E-09	4.2E-07	2.5E-09	1.4E-07	2.1E-05	1.3E-07	2.1E-05
Cobalt	1.4E-09	2.1E-07	1.3E-09	8.2E-04	7.1E-04	4.3E-06	1.5E-03
Cr(VI)	8.3E-10	1.3E-07	7.6E-10	1.4E-05	6.3E-06	3.8E-08	2.1E-05
Carbonyl Sulfide	1.4E-06			4.9E-04			4.9E-04
CS2	2.5E-07			1.1E-06			1.1E-06
Cyanide cmpds	3.1E-08			1.2E-05			1.2E-05
Formaldehyde	9.2E-08			3.6E-05			3.6E-05
H2S	1.3E-05			4.6E-03			4.6E-03
HCl	7.0E-08			2.7E-05			2.7E-05
HCN	1.2E-08			4.6E-06			4.6E-06
HF	2.7E-07			6.7E-05			6.7E-05
Lead	3.0E-09	4.6E-07	2.8E-09	-	-	-	-
Manganese	5.6E-09	8.5E-07	5.2E-09	2.2E-04	3.3E-02	2.0E-04	3.4E-02
Mercury	2.4E-09	3.7E-07	2.2E-09	2.8E-04	2.3E-03	1.4E-05	2.6E-03
Methanol	5.6E-05			4.9E-05			4.9E-05
Methyl Bromide	2.6E-07			1.8E-04			1.8E-04
Methylene Chlor	1.2E-08			1.0E-07			1.0E-07
Naphthalene	1.4E-08	9.7E-08	7.7E-09	5.3E-06	3.8E-05	3.0E-06	4.6E-05
NH3	7.1E-05			1.2E-03			1.2E-03
Nickel	2.1E-09	3.2E-07	1.9E-09	5.3E-04	2.9E-05	1.8E-07	5.6E-04
Phenol	2.0E-07			3.5E-06			3.5E-06
Propylene	6.7E-05			7.9E-05			7.9E-05
Selenium	3.0E-09	4.6E-07	2.8E-09	5.3E-07	8.1E-05	4.9E-07	8.2E-05
Sulfuric Acid	5.1E-07			1.8E-03			1.8E-03
Toluene	1.8E-10			2.1E-09			2.1E-09
Total Hazard Index				0.023	0.62	0.021	0.66

Public Health Table B.4-4. 1-Hour GLC and Determination of Acute Hazard Index at the Chronic MEIR

	1-Hour Ground Level Concentration (ug/m3)									
Sources:	HRSG Stack	Coal Dryer	CO2 Vent	GAS FUG (3 sources)	SHIFT (2 sources)	AGR FUG	SRU FUG (2 sources)	SWS FUG	Total GLC	Hazard Index
1-Hour Chi/Q:	2.4E+00	5.5E+00	6.1E+00	1.7E+01	2.0E+02	2.0E+02	1.9E+02	1.9E+02		
Acetaldehyde	1.3E-03	5.4E-04							1.9E-03	4.0E-06
Antimony	8.2E-04	3.3E-04							1.2E-03	
Arsenic	1.8E-03	7.2E-04							2.5E-03	1.3E-02
B[a]anthracene	1.7E-06	6.9E-07							2.4E-06	
Benzene	1.8E-03	7.2E-04							2.5E-03	1.9E-06
Beryllium	1.9E-04	7.8E-05							2.7E-04	
Cadmium	7.1E-03	2.9E-03							1.0E-02	
Chromium	3.8E-04	1.5E-04							5.3E-04	
Cobalt	1.9E-04	7.8E-05							2.7E-04	
Cr(VI)	1.1E-04	4.6E-05							1.6E-04	
Carbonyl Sulfide			8.1E+00	6.7E-02					8.2E+00	2.0E-01
CS2	3.4E-02	1.4E-02							4.8E-02	7.8E-06
Cyanide cmpds	4.3E-03	1.7E-03							6.0E-03	1.8E-05
Formaldehyde	1.3E-02	5.1E-03							1.8E-02	3.2E-04
H2S			4.6E+00	5.0E-01	1.2E+00	5.7E+00	7.5E-01	6.9E-01	1.3E+01	3.2E-01
HCl	9.7E-03	3.9E-03							1.4E-02	6.5E-06
HCN								3.1E-03	3.1E-03	9.2E-06
HF	3.7E-02	1.5E-02							5.2E-02	2.2E-04
Lead	4.2E-04	1.7E-04							5.8E-04	
Manganese	7.8E-04	3.1E-04							1.1E-03	
Mercury	1.5E-04	3.6E-04							5.1E-04	8.6E-04
Methanol			1.7E+01			3.8E+01			5.5E+01	2.0E-03
Methyl Bromide	3.6E-02	1.4E-02							5.0E-02	1.3E-05
Methylene Chlor	1.6E-03	6.6E-04							2.3E-03	1.6E-07
Naphthalene	1.9E-03	7.5E-04							2.6E-03	
NH3	5.7E+00	2.2E+00		1.7E-01	6.4E+00			1.6E+01	3.1E+01	9.6E-03
Nickel	2.9E-04	1.2E-04							4.1E-04	2.0E-03
Phenol	2.7E-02	1.1E-02							3.8E-02	6.6E-06
Propylene						5.2E+01			5.2E+01	
Selenium	4.2E-04	1.7E-04							5.8E-04	

Public Health Table B.4-4. 1-Hour GLC and Determination of Acute Hazard Index at the Chronic MEIR (continued)

	1-Hour Ground Level Concentration (ug/m3)									
Sources:	HRSG Stack	Coal Dryer	CO2 Vent	GAS FUG (3 sources)	SHIFT (2 sources)	AGR FUG	SRU FUG (2 sources)	SWS FUG	Total GLC	Hazard Index
1-Hour Chi/Q:	4.5E+00	7.0E+00	9.6E+00	2.2E+01	2.7E+02	3.1E+02	3.0E+02	3.12E+02		
Sulfuric Acid	7.1E-02	2.8E-02							9.9E-02	8.3E-04
Toluene	2.5E-05	9.9E-06							3.5E-05	9.3E-10
Total Hazard Index										0.54

B.5 Risk Assessment Results for the Acute MEIR Receptor

Risk assessment results for the acute MEIR are presented in the tables below:

PUBLIC HEALTH Table B.5-1 Average Annual GLC and Soil Concentration at the Acute MEIR

PUBLIC HEALTH Table B.5-2 Determination of Cancer Risk at the Acute MEIR

PUBLIC HEALTH Table B.5.3 Determination of Noncancer Chronic Hazard Index at the Acute MEIR

PUBLIC HEALTH Table B.5.4 1-Hour GLC and Determination of Acute Hazard Index at the Acute MEIR

Public Health Table B.5-1 Average Annual GLC and Soil Concentration at the Acute MEIR

	Average Annual Ground Level Concentration (ug/m3)									
Sources:	HRSG Stack	Coal Dryer	CO2 Vent	GAS FUG (3 sources)	SHIFT (2 sources)	AGR FUG	SRU FUG (2 sources)	SWS FUG	Total GLC	Soil Conc.
Avg annual Chi/Q:	2.3E-02	4.9E-02	6.7E-02	1.1E-01	5.6E-01	5.9E-01	6.2E-01	6.4E-01		
Acetaldehyde	2.4E-06	8.9E-07							3.3E-06	
Antimony	1.5E-06	5.5E-07							2.0E-06	8.3E-03
Arsenic	3.2E-06	1.2E-06							4.4E-06	1.8E-02
B[a]anthracene	3.0E-09	1.1E-09							4.2E-09	8.2E-07
Benzene	3.2E-06	1.2E-06							4.4E-06	
Beryllium	3.4E-07	1.3E-07							4.7E-07	2.0E-03
Cadmium	1.3E-05	4.8E-06							1.7E-05	7.2E-02
Chromium	6.7E-07	2.5E-07							9.2E-07	3.8E-03
Cobalt	3.4E-07	1.3E-07							4.7E-07	2.0E-03
Cr(VI)	2.0E-07	7.6E-08							2.8E-07	1.1E-03
Carbonyl Sulfide			1.0E-03	8.9E-05					1.1E-03	
CS2	6.1E-05	2.3E-05							8.3E-05	
Cyanide cmpds	7.6E-06	2.8E-06							1.0E-05	
Formaldehyde	2.2E-05	8.4E-06							3.1E-05	
H2S			5.8E-04	6.4E-04	6.7E-04	3.4E-03	5.0E-04	4.6E-04	6.3E-03	
HCl	1.7E-05	6.5E-06							2.4E-05	
HCN								6.3E-06	6.3E-06	
HF	6.6E-05	2.5E-05							9.0E-05	
Lead	7.4E-07	2.8E-07							1.0E-06	4.2E-03
Manganese	1.4E-06	5.2E-07							1.9E-06	7.8E-03
Mercury	2.7E-07	5.9E-07							8.5E-07	3.5E-03
Methanol			9.4E-04			2.5E-02			2.6E-02	
Methyl Bromide	6.3E-05	2.4E-05							8.7E-05	
Methylene Chlor	2.9E-06	1.1E-06							4.0E-06	
Naphthalene	3.3E-06	1.2E-06							4.5E-06	8.9E-04
NH3	1.0E-02	3.8E-03		2.1E-04	3.6E-03			1.1E-02	2.9E-02	
Nickel	5.1E-07	1.9E-07							7.1E-07	2.9E-03
Phenol	4.9E-05	1.8E-05							6.7E-05	
Propylene						3.1E-02			3.1E-02	
Selenium	7.4E-07	2.8E-07							1.0E-06	4.2E-03
Sulfuric Acid	1.3E-04	4.7E-05							1.7E-04	
Toluene	4.4E-08	1.6E-08							6.0E-08	

Public Health Table B.5-2. Determination of Cancer Risk at the Acute MEIR

	Cancer Risk												
Substance	Inhalation				Soil Ingestion				Dermal Absorption				TOTAL RISK
age range	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	
Substance													
Acetaldehyde	4.0E-13	9.8E-12	1.4E-11	2.1E-12	-	-	-	-	-	-	-	-	2.6E-11
Antimony	-	-	-	-	-	-	-	-	-	-	-	-	-
Arsenic	6.5E-10	1.6E-08	2.2E-08	3.4E-09	2.8E-09	3.0E-07	1.6E-07	1.6E-08	4.1E-10	5.5E-09	2.3E-08	2.3E-09	5.4E-07
B[a]anthracene	2.0E-14	4.9E-13	7.0E-13	1.0E-13	1.0E-13	1.1E-11	5.7E-12	5.7E-13	3.3E-14	4.3E-13	1.8E-12	1.8E-13	2.1E-11
Benzene	5.4E-12	1.3E-10	1.9E-10	2.8E-11	-	-	-	-	-	-	-	-	3.5E-10
Beryllium	4.9E-11	1.2E-09	1.7E-09	2.5E-10	-	-	-	-	-	-	-	-	3.2E-09
Cadmium	3.2E-09	7.8E-08	1.1E-07	1.7E-08	-	-	-	-	-	-	-	-	2.1E-07
Chromium	-	-	-	-	-	-	-	-	-	-	-	-	-
Cobalt	-	-	-	-	-	-	-	-	-	-	-	-	-
Cr(VI)	1.8E-09	4.2E-08	6.1E-08	9.1E-09	-	-	-	-	-	-	-	-	1.1E-07
Carbonyl Sulfide	-	-	-	-	-	-	-	-	-	-	-	-	-
CS2	-	-	-	-	-	-	-	-	-	-	-	-	-
Cyanide cmpds	-	-	-	-	-	-	-	-	-	-	-	-	-
Formaldehyde	8.0E-12	1.9E-10	2.8E-10	4.2E-11	-	-	-	-	-	-	-	-	5.2E-10
H2S	-	-	-	-	-	-	-	-	-	-	-	-	-
HCl	-	-	-	-	-	-	-	-	-	-	-	-	-
HCN	-	-	-	-	-	-	-	-	-	-	-	-	-
HF	-	-	-	-	-	-	-	-	-	-	-	-	-
Lead	5.3E-13	1.3E-11	1.8E-11	2.8E-12	3.7E-12	3.9E-10	2.1E-10	2.1E-11	9.1E-14	1.2E-12	5.0E-12	5.1E-13	6.7E-10
Manganese	-	-	-	-	-	-	-	-	-	-	-	-	-
Mercury	-	-	-	-	-	-	-	-	-	-	-	-	-
Methanol	-	-	-	-	-	-	-	-	-	-	-	-	-
Methyl Bromide	-	-	-	-	-	-	-	-	-	-	-	-	-
Methylene Chlor	1.7E-13	4.2E-12	6.0E-12	9.0E-13	-	-	-	-	-	-	-	-	1.1E-11
Naphthalene	6.7E-12	1.6E-10	2.3E-10	3.5E-11	-	-	-	-	-	-	-	-	4.4E-10
NH3	-	-	-	-	-	-	-	-	-	-	-	-	-
Nickel	8.0E-12	1.9E-10	2.8E-10	4.1E-11	-	-	-	-	-	-	-	-	5.2E-10
Phenol	-	-	-	-	-	-	-	-	-	-	-	-	-

Public Health Table B.5-2. Determination of Cancer Risk at the Acute MEIR (continued)

	Cancer Risk												
Substance	Inhalation				Soil Ingestion				Dermal Absorption				TOTAL RISK
age range	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	
Substance													
Propylene	-	-	-	-	-	-	-	-	-	-	-	-	-
Selenium	-	-	-	-	-	-	-	-	-	-	-	-	-
Sulfuric Acid	-	-	-	-	-	-	-	-	-	-	-	-	-
Toluene	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Risk	5.7E-09	1.4E-07	2.0E-07	3.0E-08	2.8E-09	3.0E-07	1.6E-07	1.6E-08	4.1E-10	5.5E-09	2.3E-08	2.3E-09	8.7E-07
	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
Total by pathway	-	-	-	-	-	-	-	-	-	-	-	-	-

Public Health Table B.5-3.
Determination of Noncancer Chronic Hazard Index at the Acute MEIR

		Intake (mg/kg/day)			Hazard Index		
	Inhalation	Soil Ing	Dermal Abs	Inhalation	Soil Ing	Dermal Abs	Total HI
Acetaldehyde	3.4E-09			8.5E-08			8.5E-08
Antimony	2.1E-09	3.2E-07	1.9E-09	5.2E-06	7.9E-04	4.8E-06	8.0E-04
Arsenic	4.6E-09	6.9E-07	2.5E-08	1.1E-03	2.0E-01	7.2E-03	2.1E-01
B[a]anthracene	4.4E-12	3.1E-11	2.5E-12	1.7E-09	1.2E-08	9.6E-10	1.5E-08
Benzene	4.6E-09			2.7E-07			2.7E-07
Beryllium	4.9E-10	7.5E-08	4.5E-10	2.5E-04	3.7E-05	2.3E-07	2.8E-04
Cadmium	1.8E-08	2.8E-06	1.7E-09	3.2E-03	5.5E-03	3.4E-06	8.7E-03
Chromium	9.6E-10	1.5E-07	8.9E-10	4.8E-08	7.3E-06	4.5E-08	7.4E-06
Cobalt	4.9E-10	7.5E-08	4.5E-10	2.9E-04	2.5E-04	1.5E-06	5.4E-04
Cr(VI)	2.9E-10	4.4E-08	2.7E-10	5.1E-06	2.2E-06	1.3E-08	7.3E-06
Carbonyl Sulfide	1.2E-06			4.1E-04			4.1E-04
CS2	8.7E-08			3.8E-07			3.8E-07
Cyanide cmpds	1.1E-08			4.2E-06			4.2E-06
Formaldehyde	3.2E-08			1.3E-05			1.3E-05
H2S	6.6E-06			2.3E-03			2.3E-03
HCl	2.5E-08			9.6E-06			9.6E-06
HCN	6.6E-09			2.6E-06			2.6E-06
HF	9.5E-08			2.4E-05			2.4E-05
Lead	1.1E-09	1.6E-07	9.8E-10	-	-	-	-
Manganese	2.0E-09	3.0E-07	1.8E-09	7.7E-05	1.2E-02	7.1E-05	1.2E-02
Mercury	8.9E-10	1.4E-07	8.2E-10	1.0E-04	8.5E-04	5.1E-06	9.6E-04
Methanol	2.7E-05			2.4E-05			2.4E-05
Methyl Bromide	9.1E-08			6.3E-05			6.3E-05
Methylene Chlor	4.2E-09			3.7E-08			3.7E-08
Naphthalene	4.7E-09	3.4E-08	2.7E-09	1.8E-06	1.3E-05	1.0E-06	1.6E-05
NH3	3.0E-05			5.3E-04			5.3E-04
Nickel	7.4E-10	1.1E-07	6.8E-10	1.9E-04	1.0E-05	6.2E-08	2.0E-04
Phenol	7.0E-08			1.2E-06			1.2E-06
Propylene	3.3E-05			3.8E-05			3.8E-05
Selenium	1.1E-09	1.6E-07	9.8E-10	1.9E-07	2.8E-05	1.7E-07	2.9E-05
Sulfuric Acid	1.8E-07			6.3E-04			6.3E-04
Toluene	6.3E-11			7.3E-10			7.3E-10
Total Hazard Index				0.009	0.22	0.007	0.23

Public Health Table B.5-4. 1-Hour GLC and Determination of Acute Hazard Index at the Acute MEIR

	1-Hour Ground Level Concentration (ug/m3)									
Sources:	HRSG Stack	Coal Dryer	CO2 Vent	GAS FUG (3 sources)	SHIFT (2 sources)	AGR FUG	SRU FUG (2 sources)	SWS FUG	Total GLC	Hazard Index
1-Hour Chi/Q:	4.1E+00	4.9E+00	8.7E+00	1.8E+01	2.5E+02	1.8E+02	2.2E+02	2.2E+02		
Acetaldehyde	2.3E-03	4.7E-04							2.7E-03	5.8E-06
Antimony	1.4E-03	2.9E-04							1.7E-03	
Arsenic	3.0E-03	6.3E-04							3.7E-03	1.8E-02
B[a]anthracene	2.9E-06	6.0E-07							3.5E-06	
Benzene	3.0E-03	6.3E-04							3.7E-03	2.8E-06
Beryllium	3.3E-04	6.9E-05							4.0E-04	
Cadmium	1.2E-02	2.5E-03							1.5E-02	
Chromium	6.4E-04	1.3E-04							7.8E-04	
Cobalt	3.3E-04	6.9E-05							4.0E-04	
Cr(VI)	1.9E-04	4.0E-05							2.3E-04	
Carbonyl Sulfide			1.2E+01	7.2E-02					1.2E+01	2.8E-01
CS2	5.8E-02	1.2E-02							7.0E-02	1.1E-05
Cyanide cmpds	7.2E-03	1.5E-03							8.7E-03	2.6E-05
Formaldehyde	2.1E-02	4.5E-03							2.6E-02	4.7E-04
H2S			6.6E+00	5.3E-01	1.5E+00	5.3E+00	8.8E-01	8.2E-01	1.6E+01	3.7E-01
HCl	1.6E-02	3.4E-03							2.0E-02	9.4E-06
HCN								3.7E-03	3.7E-03	1.1E-05
HF	6.3E-02	1.3E-02							7.6E-02	3.2E-04
Lead	7.1E-04	1.5E-04							8.5E-04	
Manganese	1.3E-03	2.7E-04							1.6E-03	
Mercury	2.5E-04	3.2E-04							5.7E-04	9.5E-04
Methanol			2.5E+01			3.6E+01			6.1E+01	2.2E-03
Methyl Bromide	6.0E-02	1.3E-02							7.3E-02	1.9E-05
Methylene Chlor	2.8E-03	5.8E-04							3.4E-03	2.4E-07
Naphthalene	3.2E-03	6.5E-04							3.8E-03	
NH3	9.6E+00	2.0E+00		1.9E-01	7.8E+00			1.9E+01	3.9E+01	1.2E-02
Nickel	4.9E-04	1.0E-04							5.9E-04	3.0E-03
Phenol	4.6E-02	9.7E-03							5.6E-02	9.7E-06
Propylene						4.8E+01			4.8E+01	
Selenium	7.1E-04	1.5E-04							8.5E-04	

Public Health Table B.5-4. 1-Hour GLC and Determination of Acute Hazard Index at the Acute MEIR (continued)

	1-Hour Ground Level Concentration (ug/m3)									
Sources:	HRSG Stack	Coal Dryer	CO2 Vent	GAS FUG (3 sources)	SHIFT (2 sources)	AGR FUG	SRU FUG (2 sources)	SWS FUG	Total GLC	Hazard Index
1-Hour Chi/Q:	4.5E+00	7.0E+00	9.6E+00	2.2E+01	2.7E+02	3.1E+02	3.0E+02	3.12E+02		
Sulfuric Acid	1.2E-01	2.5E-02							1.4E-01	1.2E-03
Toluene	4.2E-05	8.7E-06							5.0E-05	1.4E-09
Total Hazard Index										0.69

B.6 Risk Assessment Results for the Nearest Sensitive Receptor, Elk Hills School in Tupman

Risk assessment results for the nearest sensitive receptor, Elk Hills School in Tupman, are presented in the tables below:

- PUBLIC HEALTH Table B.6-1 Average Annual GLC and Soil Concentration at the Elk Hills School
- PUBLIC HEALTH Table B.6-2 Determination of Cancer Risk at the Elk Hills School
- PUBLIC HEALTH Table B.6.3 Determination of Noncancer Chronic Hazard Index at the Elk Hills School
- PUBLIC HEALTH Table B.6.4 1-Hour GLC and Determination of Acute Hazard Index at the Elk Hills School

Public Health Table B.6-1 Average Annual GLC and Soil Concentration at the Elk Hills School

	Average Annual Ground Level Concentration (ug/m3)									
Sources:	HRSG Stack	Coal Dryer	CO2 Vent	GAS FUG (3 sources)	SHIFT (2 sources)	AGR FUG	SRU FUG (2 sources)	SWS FUG	Total GLC	Soil Conc.
Avg annual Chi/Q:	1.7E-02	3.0E-02	3.0E-02	7.9E-02	2.0E-01	2.0E-01	2.0E-01	2.0E-01		
Acetaldehyde	1.7E-06	5.5E-07							2.3E-06	1.7E-06
Antimony	1.1E-06	3.4E-07							1.4E-06	1.1E-06
Arsenic	2.3E-06	7.4E-07							3.1E-06	2.3E-06
B[a]anthracene	2.2E-09	7.1E-10							2.9E-09	2.2E-09
Benzene	2.3E-06	7.4E-07							3.1E-06	2.3E-06
Beryllium	2.5E-07	8.0E-08							3.3E-07	2.5E-07
Cadmium	9.3E-06	3.0E-06							1.2E-05	9.3E-06
Chromium	4.9E-07	1.6E-07							6.5E-07	4.9E-07
Cobalt	2.5E-07	8.0E-08							3.3E-07	2.5E-07
Cr(VI)	1.5E-07	4.7E-08							1.9E-07	1.5E-07
Carbonyl Sulfide			4.5E-04	6.4E-05					5.2E-04	
CS2	4.4E-05	1.4E-05							5.9E-05	4.4E-05
Cyanide cmpds	5.5E-06	1.8E-06							7.3E-06	5.5E-06
Formaldehyde	1.6E-05	5.2E-06							2.2E-05	1.6E-05
H2S			2.6E-04	4.6E-04	2.4E-04	1.2E-03	1.6E-04	1.4E-04	2.4E-03	
HCl	1.3E-05	4.0E-06							1.7E-05	1.3E-05
HCN								2.0E-06	2.0E-06	
HF	4.8E-05	1.5E-05							6.3E-05	4.8E-05
Lead	5.4E-07	1.7E-07							7.2E-07	5.4E-07
Manganese	1.0E-06	3.2E-07							1.3E-06	1.0E-06
Mercury	2.0E-07	3.6E-07							5.6E-07	2.0E-07
Methanol			4.1E-04			8.5E-03			8.9E-03	
Methyl Bromide	4.6E-05	1.5E-05							6.1E-05	4.6E-05
Methylene Chlor	2.1E-06	6.8E-07							2.8E-06	2.1E-06
Naphthalene	2.4E-06	7.7E-07							3.2E-06	2.4E-06
NH3	7.4E-03	2.4E-03		1.5E-04	1.3E-03			3.5E-03	1.5E-02	7.4E-03
Nickel	3.8E-07	1.2E-07							5.0E-07	3.8E-07
Phenol	3.6E-05	1.1E-05							4.7E-05	3.6E-05
Propylene						1.0E-02			1.0E-02	
Selenium	5.4E-07	1.7E-07							7.2E-07	5.4E-07
Sulfuric Acid	9.2E-05	2.9E-05							1.2E-04	9.2E-05
Toluene	3.2E-08	1.0E-08							4.2E-08	3.2E-08

Public Health Table B.6-2. Determination of Cancer Risk at the Elk Hills School

	Cancer Risk												
Substance	Inhalation				Soil Ingestion				Dermal Absorption				TOTAL RISK
age range	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	
Substance													
Acetaldehyde	2.8E-13	6.9E-12	9.8E-12	1.5E-12	-	-	-	-	-	-	-	-	1.8E-11
Antimony	-	-	-	-	-	-	-	-	-	-	-	-	-
Arsenic	4.5E-10	1.1E-08	1.6E-08	2.4E-09	1.9E-09	2.1E-07	1.1E-07	1.1E-08	2.9E-10	3.8E-09	1.6E-08	1.6E-09	3.8E-07
B[a]anthracene	1.4E-14	3.4E-13	4.9E-13	7.3E-14	7.1E-14	7.6E-12	4.0E-12	4.0E-13	2.3E-14	3.0E-13	1.3E-12	1.3E-13	1.5E-11
Benzene	3.8E-12	9.1E-11	1.3E-10	2.0E-11	-	-	-	-	-	-	-	-	2.5E-10
Beryllium	3.4E-11	8.3E-10	1.2E-09	1.8E-10	-	-	-	-	-	-	-	-	2.2E-09
Cadmium	2.3E-09	5.5E-08	7.9E-08	1.2E-08	-	-	-	-	-	-	-	-	1.5E-07
Chromium	-	-	-	-	-	-	-	-	-	-	-	-	-
Cobalt	-	-	-	-	-	-	-	-	-	-	-	-	-
Cr(VI)	1.2E-09	3.0E-08	4.3E-08	6.4E-09	-	-	-	-	-	-	-	-	8.0E-08
Carbonyl Sulfide	-	-	-	-	-	-	-	-	-	-	-	-	-
CS2	-	-	-	-	-	-	-	-	-	-	-	-	-
Cyanide cmpds	-	-	-	-	-	-	-	-	-	-	-	-	-
Formaldehyde	5.6E-12	1.4E-10	2.0E-10	2.9E-11	-	-	-	-	-	-	-	-	3.7E-10
H2S	-	-	-	-	-	-	-	-	-	-	-	-	-
HCl	-	-	-	-	-	-	-	-	-	-	-	-	-
HCN	-	-	-	-	-	-	-	-	-	-	-	-	-
HF	-	-	-	-	-	-	-	-	-	-	-	-	-
Lead	3.7E-13	9.0E-12	1.3E-11	1.9E-12	2.6E-12	2.8E-10	1.4E-10	1.4E-11	6.4E-14	8.5E-13	3.5E-12	3.6E-13	4.7E-10
Manganese	-	-	-	-	-	-	-	-	-	-	-	-	-
Mercury	-	-	-	-	-	-	-	-	-	-	-	-	-
Methanol	-	-	-	-	-	-	-	-	-	-	-	-	-
Methyl Bromide	-	-	-	-	-	-	-	-	-	-	-	-	-
Methylene Chlor	1.2E-13	2.9E-12	4.2E-12	6.3E-13	-	-	-	-	-	-	-	-	7.9E-12
Naphthalene	4.7E-12	1.1E-10	1.6E-10	2.5E-11	-	-	-	-	-	-	-	-	3.1E-10
NH3	-	-	-	-	-	-	-	-	-	-	-	-	-
Nickel	5.6E-12	1.4E-10	1.9E-10	2.9E-11	-	-	-	-	-	-	-	-	3.6E-10
Phenol	-	-	-	-	-	-	-	-	-	-	-	-	-

Public Health Table B.6-2. Determination of Cancer Risk at the Elk Hills School (continued)

	Cancer Risk												
Substance	Inhalation				Soil Ingestion				Dermal Absorption				TOTAL RISK
age range	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	tri	0<2	2<16	16-30	
Substance													
Propylene	-	-	-	-	-	-	-	-	-	-	-	-	-
Selenium	-	-	-	-	-	-	-	-	-	-	-	-	-
Sulfuric Acid	-	-	-	-	-	-	-	-	-	-	-	-	-
Toluene	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Risk	4.0E-09	9.7E-08	1.4E-07	2.1E-08	2.0E-09	2.1E-07	1.1E-07	1.1E-08	2.9E-10	3.8E-09	1.6E-08	1.6E-09	6.1E-07
Total by pathway				2.6E-07				3.3E-07				2.2E-08	6.1E-07

Public Health Table B.6-3.
Determination of Noncancer Chronic Hazard Index at the Elk Hills School

		Intake (mg/kg/day)			Hazard Index		
	Inhalation	Soil Ing	Dermal Abs	Inhalation	Soil Ing	Dermal Abs	Total HI
Acetaldehyde	2.4E-09			6.0E-08			6.0E-08
Antimony	1.5E-09	2.2E-07	1.4E-09	3.7E-06	5.6E-04	3.4E-06	5.6E-04
Arsenic	3.2E-09	4.9E-07	1.8E-08	7.5E-04	1.4E-01	5.1E-03	1.4E-01
B[a]anthracene	3.1E-12	2.2E-11	1.7E-12	1.2E-09	8.6E-09	6.8E-10	1.0E-08
Benzene	3.2E-09			1.9E-07			1.9E-07
Beryllium	3.5E-10	5.3E-08	3.2E-10	1.7E-04	2.6E-05	1.6E-07	2.0E-04
Cadmium	1.3E-08	1.9E-06	1.2E-09	2.2E-03	3.9E-03	2.4E-06	6.1E-03
Chromium	6.8E-10	1.0E-07	6.2E-10	3.4E-08	5.1E-06	3.1E-08	5.2E-06
Cobalt	3.5E-10	5.3E-08	3.2E-10	2.0E-04	1.8E-04	1.1E-06	3.8E-04
Cr(VI)	2.0E-10	3.1E-08	1.9E-10	3.6E-06	1.5E-06	9.4E-09	5.1E-06
Carbonyl Sulfide	5.4E-07			1.9E-04			1.9E-04
CS2	6.1E-08			2.7E-07			2.7E-07
Cyanide cmpds	7.6E-09			3.0E-06			3.0E-06
Formaldehyde	2.3E-08			8.8E-06			8.8E-06
H2S	2.5E-06			8.8E-04			8.8E-04
HCl	1.7E-08			6.7E-06			6.7E-06
HCN	2.1E-09			8.1E-07			8.1E-07
HF	6.6E-08			1.7E-05			1.7E-05
Lead	7.5E-10	1.1E-07	6.9E-10	-	-	-	
Manganese	1.4E-09	2.1E-07	1.3E-09	5.4E-05	8.2E-03	5.0E-05	8.3E-03
Mercury	5.9E-10	8.9E-08	5.4E-10	6.8E-05	5.6E-04	3.4E-06	6.3E-04
Methanol	9.3E-06			8.1E-06			8.1E-06
Methyl Bromide	6.4E-08			4.4E-05			4.4E-05
Methylene Chlor	2.9E-09			2.6E-08			2.6E-08
Naphthalene	3.3E-09	2.4E-08	1.9E-09	1.3E-06	9.3E-06	7.4E-07	1.1E-05
NH3	1.5E-05			2.7E-04			2.7E-04
Nickel	5.2E-10	7.9E-08	4.8E-10	1.3E-04	7.2E-06	4.4E-08	1.4E-04
Phenol	4.9E-08			8.6E-07			8.6E-07
Propylene	1.1E-05			1.3E-05			1.3E-05
Selenium	7.5E-10	1.1E-07	6.9E-10	1.3E-07	2.0E-05	1.2E-07	2.0E-05
Sulfuric Acid	1.3E-07			4.4E-04			4.4E-04
Toluene	4.4E-11			5.1E-10			5.1E-10
Total Hazard Index				0.006	0.15	0.005	0.16

Public Health Table B.6-4. 1-Hour GLC and Determination of Acute Hazard Index at the Elk Hills School

	1-Hour Ground Level Concentration (ug/m3)									
Sources:	HRSG Stack	Coal Dryer	CO2 Vent	GAS FUG (3 sources)	SHIFT (2 sources)	AGR FUG	SRU FUG (2 sources)	SWS FUG	Total GLC	Hazard Index
1-Hour Chi/Q:	1.6E+00	3.3E+00	3.4E+00	8.2E+00	5.5E+01	4.8E+01	5.6E+01	5.7E+01		
Acetaldehyde	8.7E-04	3.2E-04							1.2E-03	2.5E-06
Antimony	5.3E-04	1.9E-04							7.3E-04	
Arsenic	1.2E-03	4.2E-04							1.6E-03	7.9E-03
B[a]anthracene	1.1E-06	4.1E-07							1.5E-06	
Benzene	1.2E-03	4.2E-04							1.6E-03	1.2E-06
Beryllium	1.3E-04	4.6E-05							1.7E-04	
Cadmium	4.6E-03	1.7E-03							6.3E-03	
Chromium	2.5E-04	9.0E-05							3.4E-04	
Cobalt	1.3E-04	4.6E-05							1.7E-04	
Cr(VI)	7.4E-05	2.7E-05							1.0E-04	
Carbonyl Sulfide			4.6E+00	3.2E-02					4.6E+00	1.1E-01
CS2	2.2E-02	8.1E-03							3.0E-02	4.9E-06
Cyanide cmpds	2.8E-03	1.0E-03							3.8E-03	1.1E-05
Formaldehyde	8.2E-03	3.0E-03							1.1E-02	2.0E-04
H2S			2.6E+00	2.4E-01	3.3E-01	1.4E+00	2.3E-01	2.1E-01	5.0E+00	1.2E-01
HCl	6.3E-03	2.3E-03							8.6E-03	4.1E-06
HCN								9.4E-04	9.4E-04	2.8E-06
HF	2.4E-02	8.8E-03							3.3E-02	1.4E-04
Lead	2.7E-04	9.9E-05							3.7E-04	
Manganese	5.0E-04	1.8E-04							6.9E-04	
Mercury	9.7E-05	2.1E-04							3.1E-04	5.2E-04
Methanol			9.8E+00			9.4E+00			1.9E+01	6.8E-04
Methyl Bromide	2.3E-02	8.4E-03							3.1E-02	8.1E-06
Methylene Chlor	1.1E-03	3.9E-04							1.5E-03	1.0E-07
Naphthalene	1.2E-03	4.4E-04							1.6E-03	
NH3	3.7E+00	1.3E+00		8.3E-02	1.7E+00			5.0E+00	1.2E+01	3.7E-03
Nickel	1.9E-04	6.9E-05							2.6E-04	1.3E-03
Phenol	1.8E-02	6.5E-03							2.4E-02	4.2E-06
Propylene						1.3E+01			1.3E+01	
Selenium	2.7E-04	9.9E-05							3.7E-04	

Public Health Table B.6-4. 1-Hour GLC and Determination of Acute Hazard Index at the Elk Hills School (continued)

	1-Hour Ground Level Concentration (ug/m3)									
Sources:	HRSG Stack	Coal Dryer	CO2 Vent	GAS FUG (3 sources)	SHIFT (2 sources)	AGR FUG	SRU FUG (2 sources)	SWS FUG	Total GLC	Hazard Index
1-Hour Chi/Q:	4.5E+00	7.0E+00	9.6E+00	2.2E+01	2.7E+02	3.1E+02	3.0E+02	3.12E+02		
Sulfuric Acid	4.6E-02	1.7E-02							6.3E-02	5.2E-04
Toluene	1.6E-05	5.8E-06							2.2E-05	5.9E-10
Total Hazard Index										0.24

APPENDIX C: EXISTING PUBLIC HEALTH CONCERNS

1.0 Introduction

The purpose of this assessment is to identify the current status of respiratory disease - using asthma as the primary metric and also evaluating COPD and Valley Fever – and cancer in the region near the proposed Hydrogen Energy project and in Kern County so as to enable a comparison of the prevalence of respiratory disease and cancer in this area with such disease in populations located in other parts of California.

2.0 Demographics of Kern County and California

The United States Census Bureau (2012) reports population characteristics with regards to age and racial/ethnic makeup of Kern County and of the State of California:

	Kern County	California
Population, 2010	839,631	37,253,956
Persons <5 years old, 2011	8.6%	6.7%
Persons <18 years old, 2011	29.9%	24.6%
Persons 65 and over, 2011	9.1%	11.7%

	Kern County	California
White persons, 2011	83.0%	74.0%
Black persons, 2011	6.3%	6.6%
American Indian/Alaska native, 2011	2.7%	1.7%
Asian, 2011	4.7%	13.6%
Native Hawaiian/Pacific Islander, 2011	0.3%	0.5%
Hispanic or Latino, 2011	50.0%	38.1%

3.0 Kern County Health Ranking & Air Pollution

According to the County Health Rankings and Roadmaps website (www.countyhealthrankings.org), Kern county is ranked 49th out of the 56 counties in California for overall health outcomes which include premature death and morbidity due to poor or fair health, poor physical health days, poor mental health days and low birth weight). Likewise, Kern County is ranked 55th out of 56 counties for overall health factors which include smoking, obesity, physical inactivity, excessive drinking, motor vehicle crash death rate, STDs and teen birth rate. For its physical environment (air pollution, particulate matter and ozone days[2], access to recreational facilities, limited access to healthy foods

[2] In the context of the County Health Rankings, an “ozone day” is a day in which air quality is unhealthy for sensitive populations. In the comparison with other CA counties, the annual number of unhealthy air quality days due to ozone was compared and that, along with the other aspects of physical environment (air pollution, particulate matter and ozone days, access to recreational facilities, limited access to health foods and fast food restaurants), contributed to the ranking of Kern County as last, 56th out of 56 California counties for "physical environment." This information was obtained from the website www.countyhealthrankings.org/health-factors/environmental-quality. This website says that several measures can be used to represent air quality, the most common being annual average values for fine particulate matter and ozone. In the County Health Rankings, they use two measures to represent environmental quality: annual number of days that air quality was unhealthy for sensitive populations due to (1) fine particulate matter and (2) ozone concentrations. Furthermore, researchers used an air quality model to estimate peak fine particulate matter and ozone concentrations for each day in the year and, by comparing

and fast food restaurants), Kern County ranks last, 56th out of 56 of California counties (County Health Rankings 2012).

The Kern County Public Health Services Department has published a “Call to Action Plan”[3] in order to address the chronic disease rates and issues of overweight and obesity that have reached epidemic levels in Kern County with more than 60 percent of the teens and adult population being overweight or obese. Kern ranks highest in California for deaths from heart disease and second highest for diabetes deaths. The goal of the action plan is to improve the health of Kern County residents through a multi-faceted approach to the problem (Kern County 2012a).

In 2010 the “Kern County Community Health Needs Assessment” was released (www.healthykern.org; Healthy Kern 2010)). This report indicated that the high mortality rates in Kern County are caused, at least in part, by these factors: high suicide death rate, high heart disease death rate, and significant racial and ethnic disparities. The air quality in Kern County during 2006-2008 was rated “F” due to elevated ozone levels while the US standard is a “B” or better. Annual particulate levels in Kern County were also rated “F” during that same time period. The report also states that the quantity (in pounds) of carcinogenic substances released into the air in Kern County is increasing over time.

The American Lung Association (ALA 2012a) ranks Bakersfield-Delano, California as the third most polluted city in the nation for ozone and the first most polluted city in the nation for annual PM2.5 (year-round particle pollution) and first for 24-hour PM 2.5 (short-term particle pollution).

The ALA’s State of the Air 2012 website (ALA 2012b) gave Kern County an “F” grade for ozone, an “F” grade for 24-hour particle pollution and a “Fail” grade for annual particle pollution. In order to determine grades for counties, US EPA data for 2008-2010 at monitoring sites throughout the US was used. In the analysis, air quality is color-coded and reported as Orange (unhealthy for sensitive populations), Red (unhealthy) and Purple (very unhealthy). In the data from 2008-2010, Kern County was coded Orange for 209 days/year for ozone, Red for 48 days/year and Purple for 2 days/year. With regards to 24-hour particulate levels, Kern County was Orange for 126 days/year, Red for 21 days/year and Purple for 2 days/year.

4.0 Asthma

4.1 Asthma Mortality Data

California Breathing, a division of the Environmental Health Investigations Branch of the California Department of Public Health, reported asthma mortality statistics for 2008-2010 in county asthma profiles posted online (www.californiabreathing.org/asthma-data/county-

to NAAQS, they estimated the number of days that the air quality was poor for sensitive populations due to these contaminants.

[3] The Kern County Call to Action Plan is dated November 9, 2010. This plan is a multi-faceted approach to engage county and city governments, healthcare systems and providers, schools and before/after school providers, early childhood educators, community-based organizations, faith-based organizations and youth organizations, media outlets and the marketing industry in advancing strategies to prevent chronic disease.

asthma-profiles; California Breathing 2011). Age-adjusted asthma mortality rates are shown below:

	Age-adjusted asthma mortality rate (in deaths per million)	
Age	Kern County	State of California
0-17 years old	n/a	1.9
18+ years old	18.5	14.3
All ages	14.4	11.1

CDHS reported age-adjusted asthma deaths for counties in California based on 2000-2004 aggregate data from the Behavioral Risk Factor Surveillance System (BRFSS) and the California Health Interview Survey (CHIS). For all counties in California, the asthma death rate in 2000 to 2004 was 15.5 per million and 14.5 per million for Kern County (Milet 2007). An older report by CDHS reported age-adjusted asthma mortality rates in California for all ages, all ethnicities for 1990-1997. The rate in the state was 18.8 per million population and in Kern County it was 19.9 per million (Hernandez 2000).

Asthma mortality data can also be compared to the Healthy People 2020 target levels published by the Centers for Disease Control and Prevention and the National Institutes of Health. The Healthy People 2020 target for asthma deaths is 6.0 per million in ages 35-64 and 22.9 per million for ages 65 and older.

4.2 Asthma Prevalence

Asthma in Kern County is measured using results of California and county health surveys and other data sources. Health surveys report asthma prevalence and asthma hospitalization rates and emergency department visits, among many other parameters. Approximately 13.7 percent of adults and 13.3 percent of children in the State of California have been diagnosed with asthma at some point in their lives (Milet 2007). The 2009 California Health Interview Survey (CHIS) conducted by the University of California Los Angeles Center for Health Policy Research, reports that 15.6 percent of Kern County residents responded yes to whether they had ever been diagnosed with asthma compared to 13.7 percent of California residents.

Data on lifetime asthma prevalence in California residents were collected in the 2009 California Health Interview Survey (CHIS) and are available on-line at www.californiabreathing.org/asthma-data/county-asthma-profiles/kern-county-asthma-profile (California Breathing 2011). Pertinent data collected on lifetime asthma prevalence are summarized below:

Lifetime Asthma Prevalence by Age (2009):

	Kern County	California
Children (0-4 yrs)	n/a	7.7%
Children (ages 5-17)	n/a	16.2%
Adults (ages 18-64)	16.8%	13.8%
Adults (> 65 yrs)	16.0%	11.8%
All Ages	15.6%	13.7%

Active Asthma Prevalence by Age (2007):

	Kern County	California
Children (0-4 yrs)	n/a	6.3%
Children (ages 5-17)	16.1	10.2%
Adults (ages 18-64)	10.4%	7.8%
Adults (> 65 yrs)	14.6%	7.4%
All Ages	11.9%	8.1%

Liu (2010) reports that based on data obtained during the 2007 CHIS, the statewide prevalence of active asthma is 8.1 percent in adults and 10.4 percent in children. In Kern County the rates are 11.4 percent in adults and 14.8 percent in children. Milet (2007) reports lifetime asthma prevalence to be 12.4 percent for all counties in California compared to 14.5 percent for Kern County (based on 2001-2003 data reported by CHIS).

4.3 Asthma Hospitalization and Emergency Department Visit Data

4.3.1 Kern County and California

Asthma hospitalization data provide information on patients with asthma so severe that they are admitted to the hospital for treatment. These data do not provide information on asthma incidence in the population or on how many people visit private doctors, emergency rooms or outpatient clinics for asthma, or on the mortality rate of asthma.

The California Department of Public Health, Environmental Health Investigations Branch (EHIB 2012) provides an online health tracking program, the California Environmental Health Tracking Program (www.ehib.org). This program was used to enter an “Asthma Data Query” to evaluate the most recent data on asthma hospitalizations and emergency department visits for Kern County and the State of California.

Asthma Hospitalizations, all ages, age-adjusted per 10,000 (2009):

	Kern County	California
All ethnicities	10.66	9.42
African American/Black	32.75	29.65
Asian/PI	7.36	6.56
Hispanic/Latino	7.96	9.31
White	11.25	7.90

Emergency Department Visits due to Asthma, all ages, age-adjusted per 10,000 (2009):

	Kern County	California
All ethnicities	49.69	47.99
African American/Black	155.97	163.05
Asian/PI	16.52	18.68
Hispanic/Latino	38.42	44.53
White	47	40.36

Data on lifetime asthma hospitalizations and Emergency Department visits in Kern County and California residents, based on data collected by the California Office of Statewide Health Planning and Development (OSHPD) are available on-line at :www.californiabreathing.org/asthma-data/county-asthma-profiles/kern-county-asthma-profile (California Breathing 2011). Pertinent data are summarized below for hospitalization rates, emergency department visits and by race/ethnicity:

Asthma Hospitalization & Emergency Dept. Visit data for Kern County and California in 2010 (age-adjusted per 10,000 residents)[4]:

	Kern County	California
Asthma Hospitalization Rate		
0-17 yrs old	11.0	11.0
18+ years old	10.1	8.3
All ages	10.3	9.0
Emergency Dept. Visit Rate		
0-17 yrs old	78.4	72.6
18+ years old	38.0	36.9
All ages	48.4	46.1

Asthma Hospitalization & Emergency Dept. Visit data for Kern County and California in 2008 compared to Healthy People 2020 targets (age-adjusted rate per 10,000 residents):

	Kern County	California	HP 2020
Asthma Hospitalization Rate			
0-4 yrs old	16.4	22.0	18.1
5-64 years old	7.8	6.0	8.6
65+ years old	22.7	21.9	20.3
Emergency Dept. Visit Rate			
0-4 yrs old	93.7	102.5	95.5
5-64 years old	38.1	39.8	49.1
65+ years old	32.9	37.7	13.2

Age-adjusted asthma hospitalizations and emergency department visits by Race/Ethnicity (in 2010; per 10,000 Kern County residents):

	Hospitalizations	ED Visits
White	11.9	45.4
African-American	26.9	151.9
Hispanic	7.4	37.9
Asian/Pacific Islander	7.6	15.7

[4] Asthma hospitalization and ED visit data were obtained from the following sources:
Asthma Hospitalization and Emergency Department Visit for Kern & California in 2010) is OSHPD 2010
Asthma Hospitalization and Emergency Department Visit for Kern & California in 2008) is OSHPD 2008.

Data on preventable hospitalizations in California are reported by OSHPD for 1999-2008 (OSHPD 2010). Asthma hospitalizations for children ages 2-17 were 57.3/100,000 persons 2-17 years old in Kern County in 2008 compared to 77.6/100,000 in California for that year. In adults, the rates were 90.4/100,000 adults for Kern County compared to 82.5/100,000 in California.

Age-adjusted asthma hospitalization rates are reported by CDHS in the California County Chart Book for asthma hospitalization rates in California and Kern County for 1998 to 2000 (Stockman 2003). Age-adjusted asthma hospitalization rates by race/ethnicity for all ages and for children (ages 0-14) are presented below (annual rates per 10,000):

	Total	non-Hispanic White	African-American	Hispanic	Asian/Pacific Islander
All Ages:					
California	11.1	9.5	33.0	10.3	7.8
Kern County	8.7	10.6	21.6	5.3	n/a
Children (ages 0-14)					
California	18.1	14.9	57.6	14.9	9.7
Kern County	16.1	22.7	48.2	5.9	n/a

4.3.2 Kern County Zip Codes

Kern County health indicators are available at “Healthy Kern County,” a website that provides a single internet source for current health information. “Healthy Kern County” is a consortium of community, government and health organization partners[5] (Healthy Kern 2012). The website provides a “Community Dashboard” link where data on different diseases can be searched for by zip code.

Using the website www.zipmaps.net, the zip codes for the areas adjacent to the proposed HECA project site were identified and include:

- 93206 – Buttonwillow, north of the project site
- 93263 – Shafter, north of the project site
- 93268 – Taft, south of the project site
- 93301 – Bakersfield, east of the project site
- 93304 – Bakersfield, east of the project site
- 93305 – Bakersfield, east of the project site
- 93306 – Bakersfield, east of the project site
- 93311 – southeast of the project site
- 93312 – northeast of the project site

[5] Participants of “Healthy Kern County” include representatives from Bakersfield Memorial Hospital, Boys & Girls Club of Kern County, Delano Regional Medical, Greater Bakersfield Legal Assistance, Kaiser Permanente, Kern Community Foundation, Kern County Public Health Services Department, Kern Family Healthcare, Mercy Hospitals of Bakersfield, Pacific Health Education Center, Saint Francis Parish, San Joaquin Community Hospital and United Way of Kern County.

The Community Dashboard was queried in order to identify age-adjusted hospitalization and emergency department visit rates for asthma in the zip codes listed above, compared to rates given for the entire county, for the period of 2008-2010:

Age-adjusted Hospitalization Rate due to Asthma:

Zip Code	Adults (per 10,000 adults)	All ages (per 10,000 population)
Kern County	13.5	12.9
93206	n/a	n/a
93263	8.3	7.4
93268	13.9	12.1
93301	24.9	22.8
93304	19.2	17.6
93305	13.8	12.1
93309	10.8	10.3
93311	9.8	10.3
93312	11.2	10.9

Age-adjusted Emergency Room Visit Rate due to Asthma:

Zip Code	Adults (per 10,000 adults)	All ages (per 10,000 population)
Kern County	38.5	49.7
93206	30.5	38.3
93263	22.3	28.4
93268	16.7	21.8
93301	70.9	87.6
93304	57.2	70.3
93305	70.0	75.7
93309	35.0	46.7
93311	31.9	43.5
93312	22.9	29.0

The Environmental Health Investigations Branch of CDPH (EHIB 2012) was queried to obtain data on asthma hospitalizations and emergency department visits by selected zip codes, Kern County and California. The age-adjusted hospitalization rate due to asthma in 2009 for all ages was 9.42 per 10,000 population in California compared to 10.66 per 10,000 in Kern County. For emergency department visits due to asthma in 2009, the rate for California was 47.99 per 10,000 population and in Kern County it was 49.69 per 10,000. Data for selected zip codes in the vicinity of the proposed project are presented below:

Emergency Department Visit Rate due to Asthma per 10,000 (age-adjusted):

Zip Code	Children	Adults	All Ages
93263	40.8	16.35	22.66
93268	37.1	21.63	25.61
93301	144.25	97.03	109.2
93304	127.34	64.33	80.57
93305	102.76	71.02	79.2
93309	94.46	47.91	59.9

Emergency Department Visit Rate due to Asthma per 10,000 (age-adjusted) (continue)

Zip Code	Children	Adults	All Ages
93311	59.49	26.75	35.2
93312	43.7	25.72	30.35

A custom data request was made of California Breathing of the California Department of Public Health to obtain zip code-specific data on asthma hospitalizations and emergency department visits for selected Kern County zip codes (Milet 2012). Sufficient data was not available to compare asthma hospitalization rates in selected zip codes. Asthma emergency department visit rates in 2009, by age group and age-adjusted rates per 10,000 residents are presented below:

Asthma Emergency Department (ED) Visits, 2009, by Age Group, Age-Adjusted Rates per 10,000 Residents for Selected Kern County Zip Codes:

Zip Code	Age 0-4	Age 5-17	Age 0-17	Age 18-64	Age 65+
93263	n/a	46.7	40.8	18.1	n/a
93268	95.2	n/a	37.1	21.0	n/a
93280	54.3	37.4	41.9	30.9	n/a
93311	59.0	59.7	59.5	23.3	43.8
93314	106.1	26.4	57.8	10.3	n/a
All zip Codes Combined	63.7	40.3	46.6	20.9	32.4

4.4 Chronic Obstructive Pulmonary Disease (COPD)

Chronic Obstructive Pulmonary Disease or COPD is a group of lung diseases that includes emphysema and chronic bronchitis. COPDs are characterized by airflow obstruction in the lungs that interferes with normal breathing. 82 percent of deaths due to COPD are caused by cigarette smoking. According to the American Lung Association, COPD is the fourth leading cause of death in the United States with an age-adjusted death rate of 42.2 deaths per 100,000 population in 2001. COPD is the only lung disease with a higher age-adjusted death rate in Whites than in African-Americans (ALA 2004). The Healthy People 2020 target rate for COPD hospitalizations is 50.1 per 10,000 and 55.2 per 10,000 for COPD emergency department visits.

The California Office of Statewide Health Planning and Development reported data on preventable hospitalizations due to COPD in California (OSHPD 2010). In 2008, COPD hospitalizations for adults were 224.5 discharges per 100,000 adults in Kern County compared to 127.7 discharges per 100,000 adults in California.

The Community Dashboard was queried in order to identify age-adjusted hospitalization and emergency department visit rates for asthma in the zip codes listed above, compared to rates given for the entire county, for the period of 2008-2010 (Healthy Kern County 2012):

Age-adjusted COPD Hospitalizations and Emergency Department Visits by Zip Code (per 10,000):

Zip Code	Hospitalizations	ED Visits
Kern County	34.7	26.4
93263	26.3	14.4
93268	42.7	23.1
93301	58.5	59.8
93304	37.9	29.9
93305	31.7	31.5
93309	23.1	15.5
93311	21.6	11.0
93312	22.4	15.3

5.0 Valley Fever (Coccidioidomycosis)

Valley Fever is a fungal infection that is caused by *coccidioides immitis* organisms that are found in the soil of dry, low rainfall areas and is endemic to Kern County. Spores of the fungus can become airborne due to soil disruptions like farming, construction and wind, and can be carried by the wind for miles. If the spores are breathed into the lungs, they can cause Valley Fever. It is estimated that up to half of the people living in areas where Valley Fever is endemic have been infected. Filipinos, Hispanics, African-Americans, Native Americans and Asians are more susceptible to serious infection than whites, as are women in their third trimester of pregnancy, new mothers, people with weakened immune systems and the elderly (Mayo Clinic 2012).

Mild cases of Coccidioidomycosis, with symptoms appearing 1-3 weeks after exposure, present with flu-like symptoms of fever, chest pain and coughing and usually resolve on their own. In cases where these symptoms are more severe, the course of the disease varies and it may take months to fully recover, with the severity of the disease usually depending on the overall health of the exposed person. The initial infection may progress to a chronic pneumonia with symptoms of low-grade fever, weight loss, cough, chest pain and nodules in the lungs. In its most severe form, the infection spreads beyond the lungs to the skin, bones, liver, brain, heart, and membranes that protect the brain and spinal cord (meninges). The most severe and deadly complication is meningitis, an infection of the meninges (Mayo Clinic 2012).

Kern County experienced an epidemic of Valley Fever between 1991-1994 in which the highest annual incidences of Valley Fever that have been recorded since 1930 occurred in 1992 with 599.6 cases per 100,000 population and in 1993 with 435.8 cases per 100,000 population. Prior to the epidemic, the rate was 50.0 per 100,000 in 1990 and following the epidemic the rate fell to 61.2 per 100,000 in 1996 (Kern County 2012b).

The number of reported cases dramatically rose again in 2010 to 244.3 cases per 100,000 from a rate of 71.3 reported for 2009. 2011 has continued to show this trend with 322.2 cases per 100,000 reported (Kern County 2012b). For comparison, the 2010 rate reported for the State of California was 11.5 cases per 100,000 population (CDPH 2011).

In 2011 Kern County and Kings County were reported to have the highest coccidioidomycosis rate in California (Kern County 2012b). It appears that the higher trend for Kern County has continued in 2012, based on the number of cases reported by the Kern County Public Health Services Department (Kern County 2012b) for data collected between 2007-2012 for reporting months January – July:

# cases coccidioidomycosis	
2007	436
2008	514
2009	263
2010	550
2011	1253
2012	1136

Coccidioidomycosis rates have also been reported by city/area in Kern County with the following rates for the cities in the vicinity of the proposed project (Kern County 2012b). These data also show an increase in coccidioidomycosis cases in 2010-2011:

City/Area	2001-2008 Average	2010	2011
Bakersfield	165.2	262.5	347.2
Buttonwillow	211.9	319.3	403.1
Shafter	229.9	458.6	659.2
Taft	415.4	504.5	736.8
Wasco	259.0	526.7	699.0

6.0 Cancer

6.1 Cancer in the United States

Cancer is the second leading cause of death in the United States (following death due to heart disease), and is the cause of 1 of every 4 deaths in the nation (American Cancer Society, ACS 2012a). It has been estimated that in January 2008 there were 12 million Americans alive who were either cancer survivors or current cancer patients. The American Cancer Society estimates that nearly one-third of the 577,190 cancer deaths expected to occur in the United States in 2012 will be due to lifestyle factors related to nutrition, physical inactivity, and obesity and thus could be prevented (ACS 2012a).

The top three leading sites of new cancer cases and deaths for males are prostate, lung/bronchus and colon/rectum. For women the top three leading sites are breast, lung/bronchus and colon/rectum (ACS 2012a).

Incidence rates in the U.S. for all cancers in 2004-2008 were highest among African-American males (626 cases per 100,000 population compared to 545 per 100,000 for white males) and white females (421 cases per 100,000 population compared to 394 per 100,000 for African-American females; ACS 2012a). Incidence rates for cancers of the colon/rectum were highest for African-Americans (males and females) and for lung and prostate cancer in African-American males. White females had the highest breast cancer incidence rate (122 cases per 100,000 compared to 116 per 100,000 for African-American females; ACS 2012a).

Eheman (2012), in the "Annual Report to the Nation on the Status of Cancer, 1975-2008" reported incidence rates in the United States for all cancers and prostate cancer in males/breast cancer in females by sex and race/ethnicity for 2004-2008, per 100,000:

	Males		Females	
	All Cancers	Prostate Cancer	All Cancers	Breast Cancer
All Races	553	153	416	121
White	545	143	421	122
African-American	626	231	394	116
Asian/PI	332	79.7	284	84.9
AI/AN	428	101	362	89.2
Hispanic	423	127	333	92.3
Non-Hispanic	564	155	424	124

PI = Pacific Islander
AI/AN = American Indian/Alaska Native
White, black, API and AI/AN include Hispanic and non-Hispanic; the race and ethnicity categories are not mutually exclusive

The data presented above show that African-American males had the highest cancer incidence rates for all cancers and prostate cancer of all ethnic groups and white females had the highest rates for all cancers and breast cancer.

The American Cancer Society reported cancer mortality rates in the U.S. for 2004-2008. African-American males and females had the highest cancer mortality rates for cancers of all sites (295 per 100,000 for African-American males compared to 220 per 100,000 for white males and 178 per 100,000 for African-American females compared to 153 for white females). Mortality rates were highest for African-American males and females for cancers of the colon/rectum, for lung and prostate cancer in males, and breast cancer in females (ACS 2012a).

Cancer mortality rates were also reported in the "Annual Report to the Nation on the Status of Cancer, 1975-2008" (Eheman 2012). U.S. death rates for all cancers and lung cancer in males/lung and breast cancer in females by sex and race/ethnicity for 2004-2008 per 100,000 were:

	Males		Females		
	All Cancers	Lung Cancer	All Cancers	Lung Cancer	Breast Cancer
All Races	223	67.4	153	40.1	23.5
White	220	66.9	153	41.2	22.8
African-American	295	85.4	178	38.8	32.0
Asian/PI	135	36.7	94.1	18.5	12.2
AI/AN	190	50.5	138	33.9	17.2
Hispanic	149	32.0	102	14.3	15.1
Non-Hispanic	229	70.3	157	42.2	24.2

PI = Pacific Islander
AI/AN = American Indian/Alaska Native

Similar to cancer mortality trends reported by the American Cancer Society (2012a), African-American males had the highest cancer mortality rates for all cancers and lung cancer. African-American women also had the highest mortality rates for all cancers and breast cancer while white women and the highest mortality rate for lung cancer (Eheman 2012).

Trends in cancer mortality over time have shown decreases in rates for all cancers combined and for many of the leading cancers in men and women, as well as in nearly all racial and ethnic groups. Trends show that the incidence of some cancers is increasing, however, including several associated with overweight and obesity (Eheman 2012).

6.2 Cancer in California

Cancer is also the second leading cause of death in California, again, following heart attacks. In 2012 an estimated 144,800 Californians will be diagnosed with cancer and 55,415 people will die of the disease in 2013 (ACS 2012b). The overall cancer incidence rate in California is lower than the rate in the rest of the nation. From 1988-2007 the incidence of cancer in California declined 15 percent among men and 9 percent among women and the rate of cancer deaths declined by 24 percent among men and 19 percent among women (Hofer 2010, Morris 2010).

African American males in California have the highest overall cancer rate, followed by non-Hispanic white males. Non-Hispanic white females have the highest cancer incidence rate among women, although African American women are more likely to die of the disease (ACS 2012b).

ACS (2012b) reports the three leading cancer sites in males and females in California in terms of incidence for the period 2005-2009, by race/ethnicity:

Males:

Rank	Cancer Site	Race/Ethnicity
1st	Prostate	African America, American Indian, Chinese, Filipino, Hawaiian, Hispanic, Japanese, Pacific Islander, South Asian, non-Hispanic White
	Liver	Kampuchean, Laotian
	Lung	Vietnamese
	Colorectal	Korean
2nd	Lung	African American, American Indian, Kampuchean, Chinese, Filipino, Laotian, Pacific Islander, non-Hispanic White
	Colorectal	Hawaiian, Hispanic, Japanese, South Asian
	Liver	Vietnamese
	Prostate	Korean
3rd	Colorectal	African American, American Indian, Kampuchean, Chinese, Filipino, Laotian, Pacific Islander, non-Hispanic White
	Lung	Hawaiian, Hispanic, Japanese, South Asian
	Stomach	Korean
	Prostate	Vietnamese

Females:

Rank	Cancer Site	Race/Ethnicity
1st	Breast	All races/ethnicities
2nd	Lung	African American, American Indian, Hispanic White
	Colorectal	Kampuchean,Chinese, Filipino, Hawaiian, Hispanic, Japanese, Korean, Laotian, South Asian, Vietnamese
	Uterus	Pacific Islander
3rd	Colorectal	African American, American Indian, non-Hispanic White
	Lung	Kampuchean, Chinese, Filipino, Hawaiian, Hispanic, Japanese, Laotian, Pacific Islander, Vietnamese
	Stomach	Korean
	Uterus	South Asian

Cancer incidence and death rates in California are reported by the California Cancer Registry (CCR 2009) for 1988-2009. Rates are age-adjusted to the 2000 U.S. standard population:

Cancer incidence rates in California (per 100,000):

	Total	Male	Female
All sites	412.8	463.3	379.4
Breast	64.9	1.1	121.7
Colon & rectum	40.5	47.1	35.2
Lung & bronchus	47.8	55.7	42.2
Non-Hodgkin Lymphoma	18.1	21.9	15.1
Prostate		126.0	

Cancer death rates in California (per 100,000):

		Male	Female
All sites	158.3	189.4	137.4
Breast	12.2	0.2	22.2
Colon & rectum	14.5	17.6	12.2
Lung & bronchus	37.8	46.9	31.1
Non-Hodgkin Lymphoma	6.0	7.8	4.6
Prostate		22.4	

Cancer incidence and mortality rates by race/ethnicity and sex for California in 2009 are shown below, per 100,000 (CCR 2009):

All sites	Incidence		Mortality	
	Male	Female	Male	Female
All Races	463.3	379.4	189.4	137.4
Non-Hispanic white	502.2	422.5	202.9	146.8
African-American	541.9	405.4	281.7	186.0
Hispanic	362.8	298.8	152.2	118.1
Asian/PI	317.5	293.0	142.0	98.4

6.3 Cancer in the Kern County

Cancer incidence and mortality rates in Kern County are reported by the California Cancer Registry (CCR 2011), the California Department of Public Health (CDPH 2012) and the County of Kern Public Health Services Department (Kern County 2012c). CCR (2011) reports that the Kern County population in 2008 was comprised of 47 percent Hispanics, 42 percent non-Hispanic whites, 6 percent non-Hispanic blacks, 4 percent Asian/Pacific Islanders and 1 percent American Indian/Alaska Native.

Incidence rates and mortality rates for Kern County are compared to state rates for California's most common cancers for 2004-2008; rates are age-adjusted and expressed per 100,000 population (CCR 2011):

Males	Incidence rate		Mortality rate	
	Kern County	California	Kern County	California
All sites	495.0	494.5	224	194.2
Prostate	123.3	143.3	27.9	22.9
Lung & Bronchus	77.4	62.0	64.5	49.7
Colon & Rectum	54.7	50.3	19.9	18.1

Note: Kern County incidence rates for prostate and lung/bronchus cancers are statistically significantly different from the statewide rate. Mortality rates for lung & bronchus, prostate and all sites are statistically different.

Females	Incidence rate		Mortality rate	
	Kern County	California	Kern County	California
All sites	388.8	387.4	153.8	142.1
Breast	116.1	121.6	23.3	22.3
Lung & Bronchus	48.8	45.0	41	33.6
Colon & Rectum	36.8	38.1	13.4	13.1

Note: Kern County mortality rates for lung & bronchus and all sites are statistically different.

The County of Kern Public Health Services Department listed cancer incidence rates in Kern County for 2009 compared to California rates (Kern County 2012c). Age-adjusted rates are listed below:

Cancer incidence rates in Kern County and California (per 100,000):

	Male		Female	
	Kern County	California	Kern County	California
All Sites	470.1	483.94	331.1	390.91
Prostate	94.99	130.88	-	-
Breast (invasive)	-	-	113.8	123.17
Breast (non-invasive)	-	-	18.5	30.93
Lung & Bronchus	74.3	59.37	47.54	49.32
Color & Rectum	46.98	48.19	35.8	36.03
Non-Hodgkin Lymphoma	16.61	22.9	15.12	15.61

Age-adjusted death rates in Kern County are compared with values reported for California and Healthy People 2010 guidelines for the period of 2008-2010 (CDPH 2012):

Cancer death rates in Kern County and California (per 100,000):

	Kern County	California
All sites	167.9	151.7
Colorectal	14.2	14.1
Lung	45.1	36.1
Female Breast	21.8	20.7
Prostate	25.1	21.2

Cancer statistics in Kern County at the zip code level are not available on the Community Dashboard (Healthy Kern County 2012).

6.4 Childhood Cancer

6.4.1 United States

Childhood cancer does not encompass one single disease but rather represents a wide group of different malignancies that vary by histology, origin site, race, sex and age. The causes of cancer in children are unknown. Consistent findings have not been reported that link environmental exposures or parental occupations to childhood cancer. Only a few known conditions or agents have been determined to explain a small percentage of specific cancers in children (Down syndrome, ionizing radiation from accidents or radiation therapy, certain chemotherapeutic agents, AIDS, specific genetic syndromes; National Cancer Institute, NCI 2012).

Cancer is the leading cause of death by disease in children in the U.S; the major types of childhood cancers are leukemia and brain and other central nervous system tumors (NCI 2012). The American Cancer Society (ACS 2012c) estimates that about 12,600 new cases of childhood cancer will occur in the United States among children ages 0-14 in 2012, with an estimated 1,340 deaths. While the incidence of cancer in children has been rising slightly over the past 30 years, the mortality rate has decreased over 50 percent (NCI 2012, ACS 2012c).
The National Cancer Institute's SEER program (Surveillance, Epidemiology and End Results) has published detailed information on the incidence of childhood cancer in the United States (NCI 2009). The following age-adjusted cancer incidence and mortality rates, per 100,000 children, for all races for 2005-2009 were presented:

	Incidence		Mortality	
	Male	Female	Male	Female
All Sites	16.41	4.4	2.4	2.1
Brain & other nervous	3.4	3.1	0.7	0.7
Hodgkin Lymphoma	0.8	0.9	0.1	0.1
Leukemia	5.5	4.5	0.7	0.6

6.4.2 California

In California, the leading cause of death in children is accidents, with the second leading cause of death in children being cancer, with leukemia, central nervous system tumors and lymphomas being the most common types of cancer diagnosed in children and teenagers in California (CDPH no date). According to the American Cancer Society (2012b), more than 1,600 children and young adults under the age of 20 are diagnosed with cancer each year in California. White and Hispanic children in California have a higher incidence of cancer than children of other racial groups (NCI 2012).

Cancer incidence among children ages 0-14 in California in 2009 are given for race/ethnicity, per 100,000 age-adjusted (ACS 2012b):

	Cancer incidence rate
Non-Hispanic White	17.8
African American	13.5
Hispanic	17.6
Asian/PI	14.1

6.4.3 Kern County

The California Department of Health Services (CDHS 2002) reported that in 1975-1984, a cluster of childhood cancers was reported in Rosamond, Kern County. Eight cases of cancer occurred in children ages 0-15 in this city located in the southeastern region of the county, a rate reported to be several times higher than the rate determined for Los Angeles and San Francisco. None of the cancers were leukemia (the most common childhood cancer). Elevated rates were not found in the areas around Rosamond and the incidence of adult cancer was not elevated during the time frame of the childhood cancer cluster. The CDHS investigation did not identify a cause of the cancer cluster, and the rate of childhood cancer in Rosamond has since gone down.

CDHS also investigated a cluster of childhood cancers identified in 1984 in McFarland, Kern County in which a total of 13 cases were diagnosed by 1989, a rate that is 3-4 times what would be expected for a town the size of McFarland (Coye 1991). McFarland is located to the northeast of Bakersfield in a primarily agricultural setting. The cancer cluster was not associated with environmental contamination in the town.

Staff did not discover any current statistics on childhood cancer in Kern County.

7.0 Discussion

Kern County is ranked one of the lowest of the California counties for overall health outcomes. The city of Bakersfield in Kern County is the most polluted city in the nation for annual and 24-hour particulates in the air (PM2.5) and the third most polluted city for ozone.

The asthma mortality rate in Kern County is higher than the rate reported for the State of California. Likewise, asthma prevalence in Kern County is higher than the prevalence observed in the State of California.

Asthma hospitalization and emergency department visit rates in 2008 were reported to be lower in Kern County than in California but that trend was reversed by data reported for 2009 and 2010. Further, the 2008 data shows that the asthma hospitalization and emergency department visit rates for children and adults under age 64 are less than the target rates recommended by the Healthy People 2020 objectives. Kern County rates for the elderly, however, exceed the HP 2020 level for asthma hospitalizations by a slight margin and are more than double the HP 2020 level for asthma emergency department visits.

Within Kern County, the Bakersfield zip codes (93301, 93304, 93305) have higher hospitalizations and emergency department visit rates in adults and all ages compared to the rates reported for the county overall and for the other zip codes in the project vicinity.

Review of asthma hospitalization rates in Kern County by race/ethnicity shows that the hospitalization rate for African-Americans is 2.3 times greater than the rate for Whites and approximately 3.6 times greater than the rate for Hispanics. Similarly, the emergency department visit rate for African-Americans is 3.3 times greater than the rate for Whites and about 4.0 times greater than the rate for Hispanics.

COPD hospitalization rates in Kern County in 2008 were almost double the rate reported for California. Across the county, the highest rates were seen in Bakersfield zip codes.

Valley Fever or Coccidioidomycosis, a potentially serious infection caused by fungi endemic to Kern County soil, is exhibiting increased incidence in Kern County since 2010.

The incidence of adult cancer in Kern County is higher for some cancer sites and lower for others compared to the rates in the State of California. Cancer mortality rates of all cancer sites combined are higher in Kern County than in the State of California.

Cancer is the leading cause of death by disease in children in California and the United States, with the most common cancers being leukemia and brain and other central nervous system tumors. Within the past 30 years or so, the incidence of childhood cancer has been rising slightly while the mortality rate is declining. In the 1980s two childhood cancer clusters were identified in Kern County but nothing remarkable has been reported since.

8.0 Conclusions

This assessment has reviewed available information on the current status of respiratory disease and cancer in Kern County, California with particular attention to the region near the proposed Hydrogen Energy California project.

Studies reviewed have shown that Kern County is ranked one of the lowest counties in California for overall health outcomes, with Bakersfield being the most polluted city in the nation for particulates and the third most polluted city in the nation for ozone.

The mortality rate for asthmatics in Kern County is higher than the rate in the State of California. The city of Bakersfield was found to have the highest asthma hospitalization and emergency department visit rates of Kern County, with hospitalization of African American asthmatics 2.3 times higher than the rate of hospitalization of whites and 3.6 times greater than the hospitalization rate of Hispanics in Kern County. COPD in Kern County is double the rate in the State of California, with the highest incidence in the city of Bakersfield.

Valley Fever appears to be on the rise in Kern County.

The death rate due to cancer in Kern County adults is greater than the death rate in the State of California. In the 1980s two childhood cancer clusters were identified in Kern County but nothing remarkable has been reported since.

SOCIOECONOMICS

Lisa Worrall and Amanda Stennick

SUMMARY OF CONCLUSIONS

Energy Commission staff concludes that construction and operation of the Hydrogen Energy California (HECA) project, with the associated Enhanced Oil Recovery (EOR) component, described in the Amended Application for Certification (AFC), would not result in significant direct, indirect, or cumulative adverse socioeconomic impacts on project area housing, schools, law enforcement services, and parks. The project would therefore have no adverse socioeconomic impacts on an environmental justice population, though staff concludes that the minority population located within the buffer area does constitute an environmental justice population. The project would not induce substantial population growth, displacement of population, or demand for housing and public services. The project would result in substantial economic benefits, including employment opportunities and revenue to local governments. Staff is proposing condition of certification **SOCIO-1** to ensure to the extent possible that sales tax from the project would benefit Kern County.

INTRODUCTION

Staff's socioeconomic impact analysis evaluates the project-induced effects on existing population, employment patterns, housing, and community services (e.g. police protection, schools, and parks and recreation) that would result from construction and operation of the proposed project. Staff also reports estimates of the noteworthy public benefits likely to result from project implementation. Please refer to the **Waste Management**, **Worker Safety and Fire Protection**, and **Water Resources** sections of this document for analysis of impacts on utilities, fire protection, water supply, and wastewater disposal.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Socioeconomics Table 1 outlines the laws, ordinances, regulations, and standards (LORS) that are pertinent for socioeconomic analysis of the proposed projects.

SOCIOECONOMICS Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
State	
California Education Code, Section 17620	The governing board of any school district is authorized to levy a fee, charge, dedication, or other requirement to fund the construction or reconstruction of school facilities.
California Government Code, §§ 65996-65997	Except for a fee, charge, dedication, or other requirement authorized under Section 17620 of the Education Code, state and local public agencies may not impose fees, charges, or other financial requirements to offset the cost for school facilities.

SETTING

The HECA project would be an Integrated Gasification Combined Cycle (IGCC) poligeneration power plant with an integrated manufacturing complex. The HECA power plant would supply carbon dioxide (CO_2), a byproduct of the gasification process, to Occidental of Elk Hills, Inc. (OEHI) for use in an associated enhanced oil recovery (EOR) operation. All project components are proposed for construction and operation in the unincorporated area of western Kern County, California. Activities taking place at the main project site would include power generation and chemical manufacturing. CO_2 generated at the project site would be transported via pipeline to a processing facility in the Elk Hills Oil Field (EHOF) for use in the EOR component.

The main HECA power plant site would be located approximately 2 miles to the northwest of the community of Tupman, 4 miles to the southeast of the community of Buttonwillow, and 7 miles from the western most boundary of the city of Bakersfield. The power plant and manufacturing complex would occupy a 453-acre parcel. Another 653 acres may be purchased adjacent to the project site to function as a controlled area (i.e. a buffer between the project elements and the surrounding land uses). The project site and controlled area are currently engaged in agricultural uses, as are the lands within one-quarter mile of the project linear facilities (i.e. pipelines carrying CO_2, natural gas, process and potable water, and the electrical transmission lines). Primary access to the power plant site would be from Adohr Road.

The EOR component of the proposed project would include construction of a carbon dioxide (CO_2) processing facility with 13 satellite sites, on roughly 136 acres, in the EHOF. The processing facility would occupy 102 acres, roughly 4 miles south of the HECA power plant site. EOR would take place at 309 CO_2 injection wells and 411 oil production wells. Of the 720 required wells, 570 are already established. If approved, 150 new wells would be installed during the 20-year construction phase. The EOR processing facility would be located roughly 3 miles to the northeast of the community of Tupman, and around 3 miles directly to the north of the communities of Dustin Acres and Valley Acres. Other communities located in proximity to the EHOF include Fellows, Ford City, Maricopa, McKittrick, Taft, Taft Heights, and South Taft. Primary access to the processing facility site would be from the SR 119 and North Access Road (Gate 2) entrance, the Tupman Road and North Access Road (Gate 1) entrance, the Elk Hills Road and Skyline Road (Gates 3 and 4) entrance, and the McKittrick (Gate 5) entrance.

To assess the potential socioeconomic impacts of the proposed project, staff defined a number of unique study areas. To evaluate impacts on environmental justice populations, staff estimated a buffer area around the main HECA project site and the CO_2 processing facility site. Staff created the buffer area by merging two distinct six-mile radii, estimated from the center point of each construction site (**Socioeconomics Figure 1**). For impacts on population, housing, and parks, staff defined a study area that includes all of Kern County. To estimate "local workforce" impacts during the project construction period, staff defined a study area equal to a two-hour commute from the project site. For "local workforce" during project operations, staff defined a study area equal to a one-hour commute from the project site. Staff assumed that a two-hour drive time was equal to 120-miles and a one-hour drive time was equal to 60-miles.

Geospatial analysis identified the cities of Arvin, Bakersfield, Corcoran, Delano, Maricopa, McFarland, Porterville, Shafter, Taft, Tehachapi, and Wasco, as well as 66 Census Designated Places (CDP's), within a 60-mile buffer of the main project site. The analysis identified an additional 105 cities and 248 CDPs within a 120-mile buffer of the project site. Staff used Kern County as the primary study area for the noteworthy benefits and cumulative impact portions of the analysis. The cumulative analysis considered projects located in Fresno, Inyo, Kern, Kings, Los Angeles, San Bernardino, and Tulare counties.

USING THE 2010 US CENSUS AND US CENSUS BUREAU'S AMERICAN COMMUNITY SURVEY IN STAFF ASSESSMENTS

The decennial census is a complete 100 percent count, collected once every 10 years, and represents information from a single reference point (April 1). The main function of the decennial census is to provide counts of people for the purpose of congressional apportionment and legislative redistricting. Where the decennial census historically collected detailed information on American populations, including demographics, economics, and housing characteristics, much of this information was not collected for the 2010 Census (US Census 2008). Rather, the Bureau collects detailed descriptive information through the U.S. Census Bureau's American Community Survey (ACS). ACS estimates represent a sample of the population based on information compiled continually and aggregated into one, three, and five-year estimates ("period estimates") released every year. The primary purpose of the ACS is to measure the changing demographic, social, and economic characteristics of the U.S. population. As a result, the ACS does not provide official counts of the population in between censuses. Instead, the Census Bureau's Population Estimates Program will continue to be the official source for annual population totals by age, sex, race, and Hispanic origin.

ACS collects data at a variety of Census defined geographic levels. These range from the nation (largest geographic level) to the block group (smallest geographic level).[1] Census Bureau staff recommends the use of data no smaller than the Census tract level.[2,3] Five-year estimates are used for the following analysis as they provide the greatest detail for the smallest available geographic area. Because ACS estimates come from a sample population, a certain level of variability is expected. This variability is expressed as a margin of error (MOE), which is used to calculate a coefficient of

[1] Census Block Group - A statistical subdivision of a census tract. A block group consists of all tabulation blocks whose numbers begin with the same digit in a census tract; for example for Census 2000, BG 3 within a census tract includes all blocks numbered between 3000 and 3999. The block group is the lowest-level geographic entity for which the Census Bureau tabulates sample data. http://www.census.gov/dmd/www/glossary.html.

[2] Census Tract - A small, relatively permanent statistical subdivision of a county or statistically equivalent entity, delineated for data presentation purposes by a local group of census data users or the geographic staff of a regional census center in accordance with Census Bureau guidelines. Designed to be relatively homogeneous with respect to population, economic status, and living conditions at the time they were established. Census tracts generally contain between 1,000 and 8,000 people, with an optimum size of 4,000 people. Census tract definitions are intended to be stable over time and are considered relatively stable geographic divisions. http://www.census.gov/dmd/www/glossary.html.

[3] Census Workshop: Using the American Community Survey (ACS) and The New American Factfinder (AFF) hosted by Sacramento Area Council of Governments on May 11 & 12, 2011. Workshop presented by Barbara Ferry, U.S. Census Partnership Data Services Specialist.

variation (CV). CVs are a standardized indicator of the reliability of an estimate. While not a set rule, the U.S. Census Bureau considers the use of estimates with a CV of more than 15 percent cause for caution when interpreting the data (US Census 2009). When the CV exceeds acceptable parameters, aggregation can often improve reliability.

PROJECT-SPECIFIC DEMOGRAPHIC SCREENING

Staff's demographic screening method was designed to identify the existence of a minority or below-poverty-level population, or both, within a minimum of 6-miles of the proposed project site. It was designed using guidance from the Council on Environmental Quality (1997) and the US Environmental Protection Agency (1998). Due to changes in the data collection methods utilized by the U.S. Census Bureau, the screening process relies on 2010 Decennial Census data to determine the minority population and five-year estimates from the ACS to calculate the population below-poverty-level. Staff determined that ACS estimates at the census tract level when aggregated, were the most appropriate for use in this analysis, because they were the smallest geographic division that yielded CV values equal to, or less than, the 15 percent reliability threshold.

Minority Populations

According to *Environmental Justice: Guidance Under the National Environmental Policy Act*, minority individuals are defined as members of the following groups: American Indian or Alaskan Native; Asian or Pacific Islander; African-American; or Hispanic. An environmental justice population exists when the minority population of the potentially affected area is greater than 50 percent, or when the minority population percentage is meaningfully greater than the minority population percentage in the general population or in some other appropriate unit of geographic analysis.

Socioeconomics Figure 1 illustrates the geographic distribution of the minority population by census block, as a percentage of the total population, in the project area. To assess the potential presence of an environmental justice population in the project area, staff first estimated two radii encompassing areas equal to 6-miles from the center points of the HECA power plant site and the CO_2 processing facility site, respectively. Staff then merged the two radii to create a combined buffer area. **Socioeconomics Table 2** presents data on the minority population within the buffer area, as well as for a variety of surrounding communities and for an assortment of comparison geographies.

According to the Decennial Census, the 2010 resident population of the census blocks located within the buffer area was 3,663 persons. The minority population was 1,850 persons, which equaled roughly 51 percent of the total population. Notable population centers located within the buffer area include Buttonwillow, Dustin Acres, Tupman, and Valley Acres. Buttonwillow had a total population of 1,508 and a minority population of 1,254, equal to nearly 83 percent minority. Dustin Acres had a total population of 652, with a minority population of 159, or around 24 percent. Tupman had a smaller population with 161 residents, and a minority population of 22 residents, equal to around 14 percent. Valley Acres had a total population of 527, with a minority population of 148, or around 28 percent.

Socioeconomics Table 2
Minority Population of Communities in the Project Area

Area[1]	Total:	White alone	Minority	Percent Minority
Buffer Area **(Socioeconomics Figure 1)**	3,663	1,813	1,850	**50.6**
Buttonwillow	1,508	254	1,254	**83.2**
Dustin Acres CDP	652	493	159	24.4
Tupman CDP	161	139	22	13.7
Valley Acres CDP	527	379	148	28.1
Bakersfield	347,483	131,311	216,172	**62.2**
Derby Acres CDP	322	279	43	13.4
Fellows CDP	106	88	18	17.0
Ford City CDP	4,278	2,140	2,138	**50.0**
Maricopa	1,154	854	300	26.0
McKittrick CDP	115	99	16	13.9
South Taft CDP	2,169	1,139	1,030	47.5
Taft	9,327	5,221	4,106	44.0
Taft Heights CDP	1,949	1,439	510	26.2
Wasco	25,545	3,689	21,856	**85.6**
Kern County	839,631	323,794	515,837	**61.4**
Buttonwillow CCD	3,953	1,326	2,627	**66.5**
West Kern CCD	30,229	19,373	10,856	35.9

Notes: Bold text- minority population 50 percent or greater. [1]CDP- Census Designated Place and CCD - Census County Division.
Source: US Census 2010a.

Other notable communities located in the general project area include Bakersfield, Derby Acres, Fellows, Ford City, Maricopa, McKittrick, South Taft, Taft, Taft Heights, and Wasco. Of these, Bakersfield had a 62 percent minority population, while Ford City was 50 percent minority and Wasco was nearly 86 percent minority. Kern County as a whole showed a minority population equal to more than 61 percent of the total population. The HECA project site and the CO_2 processing site are located within two different Census County Divisions (CCDs). The Buttonwillow CCD had a minority population of nearly 67 percent, while the West Kern CCD had a minority population of only around 36 percent. **Socioeconomics Table 2** provides additional data for these geographies for comparison purposes.

Because the minority population located within buffer area was greater than 50 percent of the total population, staff concludes that the minority population located within the buffer area does constitute an environmental justice population, as defined above. Construction and operation of the proposed HECA project, including the associated EOR operation, could therefore have adverse or disproportionate impacts on an environmental justice population. Please refer to each technical section to identify whether the project has significant, unmitigated impacts on the above identified environmental justice population.

Below-Poverty-Level-Populations

Socioeconomics Table 3 shows estimates of the population living below-poverty-level from the 2007-2011 ACS Five-Year Estimates.[4,5] According to this data, approximately 1,390 people in the combined census tracts intersecting the project buffer area, about 21 percent, lived below the federal poverty threshold between 2007 and 2011 (US Census 2011a, US Census 2013) . The combined Census County Divisions (CCD's) intersecting the project buffer (Buttonwillow CCD and West Kern CCD) and Kern County's poverty data are provided in the table for comparison purposes.

Socioeconomics Table 3
Poverty Data within the Project Area

Area	Total			Income in the past 12 months below poverty level			Percent below poverty level		
	Estimate[1]	MOE	CV	Estimate	MOE	CV	Estimate	MOE	CV
Census Tracts Used to Determine Poverty Status[2]- Total	6,276	±460	4.46	1,390	±346	15.13	22.15	±5.73	15.78
Project Buffer CCD's[3]	30,484	±1,416	2.82	5,454	±910	10.14	17.89	±3.10	10.53
Kern County	792,117	±1,997	0.15	169,635	±5,542	1.99	21.40	±0.7	1.99

Notes: [1]Population for whom poverty status is determined. [2]Census tract 33.04 and 37.00 combined. [3]Buttonwillow CCD and West Kern CCD combined.
Source: US Census 2011a.

Additional Environmental Justice Population Considerations

Final Guidance for Incorporating Environmental Justice Concerns in EPA's Compliance Analyses (US EPA 1998) also encourages outreach to community-based organizations and tribal governments early in the screening process to identify the presence of distinct minority communities residing within, or in close proximity to, the proposed project site. It also encourages identification of minority groups that utilize or are dependent upon natural and cultural resources that may be affected by the proposed action. For information regarding the Energy Commission's outreach program and consultations with local Native American communities, see the **Executive Summary, Introduction,** and **Cultural Resources** sections of this document.

[4] When projects are proposed in remote locations, the population within a 6-mile radius of the project site is often quite small. The resulting sample size collected for the ACS can be too small to yield estimates with a reasonable CV. For this analysis, staff determined that data for the combined Census tracts that intersect the project buffer (tract 33.04 and 37.00) were the most appropriate, as they were the smallest geographic area with reasonable CV. Please note that the data reported by the ACS are period estimates, meaning the numbers represent the average characteristics attributable to the local population over a specified time period.

[5] According to the 2011 Poverty Thresholds published by the US Census Bureau, the poverty threshold for a single person household who is under 65 years of age is $11,702. The threshold for a family of four with two dependent children was $22,811 (UC Census 2013).

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

As discussed in the Introduction section of the PSA, this document analyzes the project's impacts pursuant to both the National Environmental Policy Act (NEPA) and CEQA. The two statutes are similar in their requirements concerning analysis of a project's impacts. Therefore, unless otherwise noted, staff's reference to and use of CEQA criteria and guidelines also encompasses and satisfies NEPA requirements for this environmental document.

CEQA defines a significant effect on the environment as "a substantial, or potentially substantial, adverse change in any of the physical conditions within the area affected by the project" (CEQA Guidelines Section 15382). Thresholds of significance serve as the benchmark for determining if a project would result in a significant adverse impact when evaluated against existing conditions (e.g., "baseline" conditions). CEQA Guidelines do not provide specific, quantifiable thresholds of significance for socioeconomic impact determinations. CEQA Guideline Section 15064(e) specifies that: "[e]conomic and social changes resulting from the project shall not be treated as significant effects on the environment." However, Section 15064(e) continues by stating that when "a physical change is caused by economic or social effects of a project, the physical change may be regarded as a significant effect in the same manner as any other physical change resulting from the project. Alternatively, the economic and social effects of a physical change may be used to determine that the physical change is a significant effect on the environment. If the physical change causes adverse economic or social effects on people, those adverse effects may be used as a factor in determining whether the physical change is significant. For example, if a project would cause overcrowding of a public facility and the overcrowding causes an adverse effect on people, the overcrowding would be regarded as a significant effect."

According to Appendix G of the State CEQA Guidelines, a project may have a significant effect on population, housing, and public services if it would:

- Induce substantial population growth in an area, either directly or indirectly;
- Displace substantial numbers of people and/or existing housing, necessitating the construction of replacement housing elsewhere; or
- Adversely impact acceptable levels of service for police protection, schools, parks and recreation, and hospitals and emergency medical response.

Staff's assessment of the significance of impacts on population, housing, police protection, schools, and parks and recreation are based on professional judgments, input from local and state agencies, and the industry-accepted two-hour commute range for construction workers and one-hour commute range for operations workers. Impacts on fire safety and emergency medical services are assessed in the **Worker Safety and Fire Protection** section of this document.

DIRECT/INDIRECT IMPACTS AND MITIGATION

Induce Substantial Population Growth

To determine whether the project would directly or indirectly induce substantial population growth, first staff analyzed the historic and projected population growth trends in the project area. Staff then evaluated whether the labor force in the surrounding region would be sufficient to meet the needs of the HECA project, including associated actions, and whether workers would need to relocate, either permanently or temporarily, to the project area. In those cases where workers would likely relocate, staff assessed whether the scope of this relocation would be sufficient to induce the construction of new housing and government facilities, or expansion of existing facilities.

Historic and Projected Population Growth

To assess long-term population growth trends in the project area, staff collected data from the U.S. Census Bureau and the California Department of Finance (DOF). **Socioeconomics Table 4** reports historic and projected population data for communities located in proximity to the project. According to this data, the population within the buffer area increased by 31 percent, from 2,789 residents in the year 2000 to 3,663 residents in 2010. The community of Buttonwillow grew by 176 persons, around 19 percent. Dustin Acres grew by 67 persons, around 11 percent. The community of Tupman lost 66 persons, or 29 percent of its total population, and Valley Acres grew by 15 persons, around 3 percent, during the same period.

Outside of the buffer area, the city of Bakersfield grew by 100,426 persons, or 41 percent. The city of Wasco grew by 4,282 persons, or 20 percent. The McKittrick CDP lost roughly 45 persons, or 28 percent of its 2000 population. The city of Taft grew by 2,927 persons, or 46 percent. Considered along with adjacent communities, the Taft urban area grew by 4,048 persons, or around 30 percent. The two CCDs of Buttonwillow and West Kern, grew by 915 persons and 2,847 persons respectively. This was equal to around 30 percent growth in the Buttonwillow CCD and 10 percent growth in the West Kern CCD. Note that these geographies include both the HECA project site and the EOR processing facility site, as well as a variety of established communities located throughout western Kern County. For this reason, population estimates reported for the Buttonwillow CCD differ significantly from the reported for the Buttonwillow CDP. Kern County reportedly grew by 177,986 persons, or 27 percent, during this period. Population projections from the California Department of Finance (DOF) indicate that the county may expect to grow by another 983,646 persons to total population of 1,823,277 persons by 2050. This would equal around 117 percent population growth over 40 years, which is equal to a compound annual average growth rate of 2 percent.

Project Labor Requirements, Workforce Availability, and Growth Inducement

Due to the complexities associated with analysis of the proposed project (such as the diverse workforce requirements of the different project components), staff assessed labor requirements, workforce availability and potential population growth inducement of the two main project components independently. Staff then combined the results of the analyses to identify potential impacts from the whole of the project.

Socioeconomics Table 4
Historical and Projected Population Growth Trends in the Project Area

Area[1]	2000	2010	Percent Change 2000-2010	2020	2030	2040	2050	Percent Change 2010-2050
Buffer Area	2,789	3,663	31	Data Not Available				
Buttonwillow CDP	1,266	1,508	19					
Dustin Acres CDP	585	652	11					
Tupman CDP	227	161	-29					
Valley Acres CDP	512	527	3					
Bakersfield	247,057	347,483	41					
Derby Acres CDP	376	322	-14					
Fellows CDP	153	106	-31					
Ford City CDP	3,512	4,278	22					
Maricopa	1,111	1,154	4					
McKittrick CDP	160	115	-28					
South Taft CDP	1,898	2,169	14					
Taft	6,400	9,327	46					
Taft Heights CDP	1,865	1,949	5					
Wasco	21,263	25,545	20					
Kern County	661,645	839,631	27	1,041,469	1,276,155	1,529,987	1,823,277	117%
Buttonwillow CCD	3,038	3,953	30					
West Kern CCD	27,382	30,229	10					

Notes: [1]CDP- Census Designated Place and CCD - Census County Division. **Sources:** US Census 2000, US Census 2010b, CA DOF 2012.

Labor Requirements for Construction of the HECA Component

The AFC states that construction of the HECA power plant and manufacturing complex component (from site preparation and grading to commercial operation) would take approximately 49 months. Based on the Commission's current schedule, publication of the Final Staff Assessment (FSA) should occur in July of 2013 (CEC 2013a). The Commission would likely make a decision in the four to five months following publication. If approved, pre-construction of the proposed project could begin as early as November of 2013 (HECA 2012a). This represents a delay of approximately five months from the original commencement date of June 2013. As such, Truck deliveries and ground disturbance would likely begin in January of 2014 and would conclude around July of 2017. Pre-commissioning and commissioning would begin in August of 2016 and commercial operation would begin in February of 2018. As shown in Table 5.9-11 of the AFC, the number of workers required for construction of this component would range from a low of 34 during pre-construction to a high of 2,461 at peak construction in the thirty-first month. The average number of on-site workers during the 49-month construction period would be around 1,160 (including construction workers and contractor staff), which is equal to roughly 4,700 job-years.[6] These estimates include both construction craft workers and other construction staff. Craft workers would make up the majority of the workforce throughout the construction period. The craft workforce would encompass a variety of occupations ranging from boilermakers and carpenters to pipefitters, sheet metal workers, and teamsters. The number of craft workers required during construction would range from a low of 16 workers during pre-construction to a high of 2,090 at peak construction. Construction would require an average of around 930 on-site craft workers throughout the 49-month construction period. This would be the equivalent of roughly 3,800 job-years. Construction staff would make up a smaller portion of the construction workforce and would include management, engineering, document control occupations, as well as assorted subcontractor's staff, commissioning staff, and some administrative and operating staff. The number of construction staff would range from a low of 18 during pre-construction to a high of over 417 during month-32. There would be an average of 230 staff on site during construction, equal to roughly 900 job years. Note that in month-32 the number of construction staff would begin to decline, corresponding to an increase in the number of commissioning and operating staff.

Workforce Availability for Construction of the HECA Component

The applicant anticipates that 60 percent of the construction workforce for the power plant component would come from within Kern County, with the remainder coming from Los Angeles County. According to a representative of the Building Trades Council (BTC) for Kern, Inyo, and Mono counties, the project contractor has signed a Project Labor Agreement (PLA) with local BTC affiliates (CEC 2012a). Due to the structure and hiring hall procedures of the participating unions, the BTC expects that between 65 and 75 percent of the construction workforce would come from Kern County. The remainder

[6] One job-year is the equivalent of one full-time job held for a period of one year. For example, this could equal one full-time job held for 12 months, two full-time jobs held for six months, three full-time jobs held for four months, or two half-time jobs held for one-year, and so on.

would primarily come from the area around Lancaster and Palmdale in Los Angeles County. Additional workers would also come from Fresno County, as some of the participating local unions have existing offices there. The representative from the BTC noted existing high unemployment among Kern County construction workers and emphasized that many have needed to travel outside of Kern County to find work over the past few years. Construction of the HECA component would represent a substantial increase in the availability of local employment and the existence of a PLA helps to ensure that local workers would benefit to the greatest extent possible.

Socioeconomics Table 5 provides occupational employment estimates published by the California Employment Development Department (EDD) for Kern County. The occupations listed roughly correspond to those reported under construction craft employment in Table 5.8-11 of the AFC (HECA 2012a) and Table A25-1 of the applicant's Responses to CEC Workshop Requests – Nos. A1 through A32 (HECA 2012b). Although data were not available for all occupational categories, staff confirmed that the existing labor force in Kern County would be sufficient to accommodate most of the craft labor requirements of the HECA component. The occupational categories most likely to experience a shortfall of local craft workers during peak demand include reinforcing iron and rebar workers, as well as plumbers and pipefitters. Data were unavailable for two of the 14 occupational employment categories due to data suppression.[7] These include boilermakers and insulation workers. Since suppressed data are often an indicator of low levels of employment, workers in these occupations would likely be in short supply. For carpenters and millwrights, peak labor demand during project construction would equal 30 to 40 percent of the local workforce in each category. This could result in shortages during peak construction, if there is competition from other projects. Local labor unions can respond to craft labor shortages in a number of ways. These include outreach to unemployed residents, enrollment of new apprentices into craft training programs, and the recruitment of workers from outside the local area.

The employment estimates for construction staff reported in Table 5.8-11 of the AFC lack the specificity required to match project labor requirements with occupational employment estimates (HECA 2012a). At the data response workshop held on September 27, 2012, staff requested clarification regarding the types of occupations associated with construction staff employment. The applicant, in their response to the workshop data requests, provided clarification of the occupations associated with construction staff (HECA 2012b). Although the clarification was solely qualitative and did not facilitate quantitative comparison, staff confirmed that the existing labor force in Kern County would be sufficient to accommodate most of the staff labor requirements of the HECA project. This is because the project would require a relatively small number of construction staff in any given occupational category. For example, the project would require only six staff in document control, six in off-plot construction, 15 in engineering, and 40 in commissioning. Each of these employment categories would include workers from an assortment of occupations. For example, engineering staff would include

[7] Data are suppressed for a variety of reasons, including failure to meet Bureau of Labor Statistics (BLS) quality standards, or the need to protect the confidentiality of survey respondents. The BLS is unable to provide the specifics on why an estimate was not released.

mechanical engineers, civil engineers, structural engineers, electrical engineers, instrument and control engineers, quality engineers, and surveyors. Construction staff employment would thus require a very small number of workers within each occupational category. This would increase the likelihood that the project could find qualified workers within the local area and would decrease the need to recruit workers from outside of Kern County.

Socioeconomics Table 5
Construction Craft Labor for Select Occupations, Kern County, 2000 and 2011

SOC Code	Occupation Type	Estimated Workforce		Peak Demand
		2000	2011	
47-2011	Boilermakers	n.a.	n.a.	140
47-2031	Carpenters	900	550	220
47-2051	Cement Finishers	530	290	20
47-2111	Electricians	990	1,610	400
47-2130	Insulation Workers	110	n.a.	220
47-2171	Reinforcing Iron	90	80	280
47-2061	Construction Laborers	1,530	2,180	163
49-9044	Millwrights	80	360	120
47-2073	Operating Engineers	840	1,040	200
47-2141	Painters, Construction	390	310	50
47-2152	Plumbers and Pipefitters	980	690	720
47-2211	Sheet metal Workers	380	140	14
53-7051	Truck and Tractor Operators	1,230	1,120	n.a.
49-9051	Electric Power-Line Installers	n.a.	300	10

Source: CA EDD 2001, CA EDD 2011, HECA 2012a.

Growth Inducing Impacts from Construction of the HECA Component

Based on the construction labor requirements reported in the AFC and estimates of labor availability from the BTC and EDD, staff determined that the HECA component of the project would likely achieve a 60 to 75 percent local workforce. With peak construction labor demand estimated at nearly 2,500 workers, staff estimated that between 600 and 1,000 workers would need to relocate, temporarily or permanently, to the project area to participate in construction activities. Note that temporary relocation may entail commuting to the project area on a daily or weekly basis. While daily commuters would have little to no impact on residential housing and services, this analysis assumes a worst-case scenario in which all non-local workers would relocate permanently or would commute on a weekly basis, thus affecting residential housing availability and municipal service provision.

To evaluate the relative ability of the surrounding communities to absorb this influx of population, staff developed a gravity model for migration, similar to that used by the applicant. The model does not provide a precise forecast. Rather it offers a general indication of the attractiveness of different communities and helps quantify worker relocation preferences. Gravity models rely on the assumption that the propensity to relocate to a given location is directly proportional to population size and inversely proportional to the square of the distance from the project site. Population size is a proxy for the relative utility or desirability of a given location, as defined by the quality and variety of community amenities. Staff used the inverse of the squared driving distance because the relative attractiveness of a location typically diminishes with distance from one's place of work. The results of the gravity model suggest that of those workers that would relocate to the project area, over 50 percent would prefer to relocate to the city of Bakersfield. The remainder would prefer to locate in more than 30 other cities, towns, and CDPs located throughout Kern County. Around 8 percent of the non-local workforce, for example, would prefer to locate in the Rosedale CDP, while roughly 5 percent would prefer the communities of Oildale, Wasco, or Shafter. Despite the close proximity of the communities of Buttonwillow or Tupman to the project site, only 2 percent of the non-local workforce would likely seek to live in either community. Staff presumes this would be due to their relatively small size and lack of amenities, compared to the nearby city of Bakersfield.

To estimate the total population change that could occur due to construction, staff multiplied the estimated number of workers who would relocate to each community by the average household size for Kern County from the 2010 Census of 3.15. Based on these estimates and a total non-local workforce equal to 40 percent of labor demand, a maximum of around 500 workers and their families could relocate to the city of Bakersfield. This would equal around 1,650 people and a 0.5 percent increase in the population. The Rosedale CDP could also experience a sizable increase in population of around 75 workers and 230 people, equal to a 1.7 percent increase in the population. Other notable population impacts could occur in the communities of Buttonwillow and Tupman. Due to its proximity to the project site, Buttonwillow could experience an increase in population of around 70 people, including 20 project construction workers. This would equal an increase in the existing population of more than 4.5 percent. Likewise, the community of Tupman could experience an increase of nearly 55 people, including almost 20 project construction workers, for a total increase of over 30 percent.

Labor Requirements for Construction of the OEHI/EOR Component

The supplemental environmental analysis provided in Appendix A of the AFC states that construction of the OEHI EOR operation is scheduled to take place incrementally over a 20-year implementation schedule. Pending certification of the HECA power plant, construction associated with the EOR component would begin in 2014 and would continue through 2033. Table 3-4 of Appendix A reports that the number of workers required for the project would range from a low of seven to a high of 385. The number of workers would fluctuate substantially from year to year. Years with the highest average workers per day are those that include construction activities related to the CO_2 processing facility, as well as the satellite stations and pipelines. Throughout the 20-year construction period, the applicant anticipates ongoing installation and conversion of new and existing well sites.

Page 3.0-13 of Appendix A describes that OEHI currently employs around 345 workers and 2,650 contract personnel in the EHOF. The applicant anticipates that 75 percent of the labor required for the well and pipeline installations can be accommodated using the existing employed workforce. They also estimate that 25 percent of the labor required for construction of the processing facility and satellite stations would come from the existing employed workforce. The construction labor requirements reported in Appendix A do not differentiate between the number of workers required for construction of the processing facility and satellite stations, compared to the number required for well installation and conversion. Because of this, staff requested that the applicant provide a breakdown of the personnel required for installation of the various facilities (CEC 2013b). As illustrated in **Socioeconomics Table 6**, the EOR component could require up to 218 workers, in addition to those already employed or contracted in the EHOF, for construction of the main CO_2 processing plant and satellite facilities. Up to 50 new workers would also be required to accommodate pipeline construction and well installations. Combined, this could equal up to around 240 new workers. As noted earlier, the number of workers would fluctuate substantially from year-to-year.

Socioeconomics Table 6
OEHI/EOR Construction Personnel Requirements
(Average Annual Daily-Employment)

Year	Total, All Types	Main Plant	Satellite Stations	Pipeline Installation	Well Install/ Convert
2014	195	177	4	10	4
2015	385	255	35	92	3
2016	64	0	17	37	10
2017	299	128	18	144	9
2018	231	192	15	21	3
2019	329	319	2	5	3
2020	49	0	17	25	7
2021	74	0	17	53	4
2022	7	0	0	0	7
2023	19	0	2	3	14
2024	85	35	17	30	3
2025	81	70	0	0	11
2026	8	0	2	3	3
2027	69	0	18	47	4
2028	217	0	18	196	3
2029	53	0	16	26	11
2030	9	0	2	3	4
2031	52	0	16	24	12
2032	7	0	2	1	4
2033	42	0	16	14	12

Source: CEC 2013b.

Local Workforce Availability for Construction of the OEHI/EOR Component

As noted earlier, the applicant anticipates that 75 percent of the workforce required for construction of new wells and pipelines would come from the existing OEHI workforce, including contract personnel. An additional 25 percent of the workforce required for construction of the processing facility and satellite stations would come from these

Socioeconomics Table 7
OEHI/EOR Construction Personnel Requirements by Craft Type
(Average Annual Daily-Employment)

Year	Total	Carpenter	Equipment Operator	Welder	Pipe Fitter	Electrician	Mechanical Other	Other
2014	195	12	35	35	23	39	35	16
2015	385	23	69	69	47	77	69	31
2016	64	4	12	11	8	13	11	5
2017	299	18	54	54	36	59	54	24
2018	231	14	42	41	28	46	42	18
2019	329	20	59	60	39	66	59	26
2020	49	3	9	9	6	10	8	4
2021	74	5	13	13	9	15	13	6
2022	7	1	1	1	1	1	1	1
2023	19	1	3	3	2	4	4	2
2024	85	5	15	16	10	17	15	7
2025	81	5	15	14	10	17	14	6
2026	8	0	1	2	2	1	1	1
2027	69	4	12	12	9	14	12	6
2028	217	13	39	39	26	43	40	17
2029	53	3	9	10	6	10	11	4
2030	8	0	1	1	1	1	3	1
2031	52	3	9	9	6	11	10	4
2032	7	0	1	2	1	1	1	1
2033	42	3	8	7	4	9	8	3

Source: CEC 2013b.

sources. Based on these estimates of labor force utilization, construction of the EOR facilities would require up to 240 additional workers, beyond those already employed or contracted with OEHI. According to data published by the California Employment Development Department (EDD), there were roughly 14,850 workers employed in Kern County in the construction and extraction trades as of May 2010. The maximum number of workers that OEHI would need to hire to meet their projected labor requirements would equal only about 2 percent of this total (CA EDD 2011).

Socioeconomics Table 7 reports the average number of workers, per day, per year, that would be required in the 10 major occupational categories used by the project. During peak construction in 2015, the project would require up to 23 carpenters, 69 equipment operators, 69 welders, 47 pipefitters, 69 mechanical workers, 77 electrical workers (including 46 electricians, 23 electrical technicians, and eight other electrical workers), and 31 other construction workers. **Socioeconomics Table 8** provides occupational employment estimates published by EDD for Kern County. The occupations listed roughly correspond to those reported in Table 7 above. Based on this data, staff confirmed that the existing labor force in Kern County would be sufficient to accommodate the craft labor requirements of the OEHI/EOR project component.

Socioeconomics Table 8
Construction Craft Labor for Select Occupations,
Kern County, 2000 and 2011

SOC Code	Occupation Type	Estimated Workforce		Peak Demand
		2000	2011	
	Carpenters	**900**	**550**	**23**
47-2031	Carpenters	900	550	
	Equipment Operators	**840**	**1,040**	**69**
47-2073	Operating Engineers	840	1,040	
	Welders	**910**	**1,000**	**69**
51-4121	Welders, Solderers, and Brazers	910	1,000	
	Plumbers and Pipefitter	**1,270**	**900**	**47**
47-2152	Plumbers and Pipefitters	980	690	
47-3015	Helpers, Pipelayer, Plumber, etc.	290	210	
	Electrical Workers	**1,150**	**1,610**	**77**
47-2111	Electricians	990	1,610	
47-3013	Electrical Technicians	160	n.a.	
	Other Mechanical	**330**	**630**	**69**
17-2141	Mechanical Engineers	330	630	
	Other	**1,530**	**2,180**	**31**
47-2061	Construction Laborers	1,530	2,180	

Source: CA EDD 2001, CA EDD 2011, HECA 2012c.

In the event that trained workers were not available within the local area, one option would be for the project to hire existing unemployed residents. As of November 2012, Kern County had a total unemployed population of 47,400 residents, equal to around 12.4 percent of the total labor force (CA EDD 2012). The maximum number of workers that OEHI would need to hire would equal only 0.5 percent of the existing unemployed population. As was described for the HECA project, employers can respond to labor shortages in a number of ways. These include outreach to unemployed residents, enrollment of new apprentices into craft training programs, and the recruitment of workers from outside the local area.

Growth Inducing Impacts from Construction of the OEHI/EOR Component

Based on the construction labor requirements discussed above, staff determined that construction of the OEHI/EOR component could temporarily require up to 240 workers, beyond those currently employed or contracted with OEHI. Given the large number of existing Kern County workers employed in the construction and extraction trades, as well as the high unemployment currently present in Kern County, staff believes that the OEHI would be able to satisfy the additional labor requirements through the recruitment of existing Kern County residents. To the degree that some workers would need to relocate into the project area from outside of Kern County, staff anticipates that most would do so on a temporary basis. This is because the number of workers required for construction of the EOR facilities would fluctuate substantially from year-to-year, providing little incentive for workers to relocate permanently to the project area.
The temporary relocation or workers would entail commuting to the project area on a daily or weekly basis. While daily commuters would have little to no impact on residential housing and services, this analysis assumes a worst-case scenario in which all non-local workers employed in construction of EOR facilities would commute on a weekly basis, thus affecting housing availability and public service provision.

To evaluate the relative ability of the surrounding communities to absorb this influx of population, staff utilized a gravity model for migration, comparable to that used for analysis of the HECA component. The results of the gravity model suggest that of those workers that would temporarily relocate to the project area during the construction period, around 59 percent would prefer housing in the city of Bakersfield. This could equal more than 140 workers, resulting in a temporary 0.04 percent increase in the city's population. The remainder would prefer to locate in some 25 other cities, towns, and CDPs located throughout western Kern County. More than 4 percent of the workforce, for example, would prefer to locate in the greater Taft area, including the city of Taft, Taft Heights, South Taft, and Ford City. This could equal more than 20 workers, resulting in a temporary increase in the population of about 0.13 percent. Roughly 4 percent would prefer to locate in Rosedale and Oildale. Meaning that up to 10 workers could seek housing in Rosedale, while another nine could seek residence in Oildale. This would translate into temporary population increases of 0.07 and 0.03 percent, respectively. Despite the close proximity of the community of Tupman to the EHOF, only a little over 1 percent of the temporary workforce would be expected to look for housing there. This would equal a maximum of only three workers, resulting in a population increase of less than 2 percent.

Growth Inducing Impacts from Construction of the Whole of the Project

To ascertain whether construction of the whole of the project, including both the HECA power plant and the EOR components, would result in substantial induced population growth, staff combined the results of the two gravity models described above. The combined results suggest that of those workers that would temporarily relocate to the project area during the initial construction period (i.e. the period during which the two construction schedules would overlap), around 54 percent would prefer housing in the city of Bakersfield. This could equal more than 650 workers, resulting in a temporary increase in the city's population of up to 0.6 percent, if workers are assumed to relocate with their families. The remaining workers would likely prefer to locate in around 40 other cities, towns, and CDPs throughout western Kern County. Most notably, the model indicates that around 20 workers might prefer to temporarily locate in Tupman, resulting in an increase in the resident population of up 12 percent. If those workers were to relocate with their families (which is unlikely for workers hired to construct the EOR facilities), this could result in the introduction of more than 60 people, or around 39 percent of the 2010 resident population. Another 24 workers could seek residence in Buttonwillow, resulting in a population increase of around 1.6 percent. If these workers were to relocate along with their families, this could represent closer to five percent population growth. Around 10 workers could relocate to Dustin Acres CDP, increasing the population by between 1.5 and 4.5 percent. Valley Acres, by comparison, might see around five construction workers, increasing the population by around one to three percent. Another 75 construction workers could relocate to the greater Taft area – including Ford City, Taft, Taft Heights, and South Taft – increasing the population by between two and five percent.

Labor Requirements for Operation of the HECA Component

Table 5.8-11 of the AFC indicates that hiring for operation of the HECA power plant and manufacturing component would begin in month 32 of project construction and would conclude around 18 months later on commencement of commercial operations in February of 2018 (HECA 2012a). The project would require an annual average of 200 full-time permanent employees. Page 5.8-16 of the AFC states that the operations workforce would include 88 operating technicians working in four teams of 22 workers on 12-hour shifts. Operating staff would also include 65 contract maintenance workers, nine administrative support staff , nine material coordination and procurement staff, eight health and safety staff, five production planning staff, three laboratory staff, two training staff, one human resources person, and six management and administration staff (HECA 2012b).

Workforce Availability for Operation of the HECA Component

The applicant expects 60 percent of the operations workforce to come from within Kern County. The remainder would relocate or commute from surrounding areas, such as the County of Los Angeles. **Socioeconomics Table 9** provides employment estimates for select occupations associated with the operations crews and equipment maintenance staff. Based on these estimates, staff concludes that the existing labor force in Kern County would be sufficient to accommodate most of the operational labor requirements of the HECA project. Staff estimates that there were approximately 1,700 workers in Kern County in 2011 with skills appropriate for employment on the HECA operations crews. These include power plant operators, stationary engineers and boiler operators, wastewater treatment plant operators, chemical plant operators, gas plant operators, petroleum pump and refinery operators, and other plant and system operators. Kern County also has over 1,000 workers with skills appropriate for employment as contract based equipment maintenance staff. These include industrial machinery maintenance workers and other general maintenance and repair workers. Staff does not anticipate a shortfall of workers in the remaining nine employment categories reported in Table 26 of the applicant's Response to CEC Workshop Requests – Nos. A1 through A32 (HECA 2012b). This is due to the relatively small number of workers required in each employment category. The applicant states on Page 5.8-16 of the AFC that the HECA, LLC, would provide local preference for hiring (HECA 2012a). Given the large labor pool, staff expects that, in the absence of cumulative labor impacts from other projects, the HECA project could achieve greater than 60 percent local hiring.

Socioeconomics Table 9
Operations Staff Labor for Select Occupations, Kern County, 2000 and 2011

SOC Code	Occupation Type	Estimated Workforce		Peak Demand
		2000	2011	
	Operations Crew	**1,180**	**1,690**	**88**
51-8013	Power Plant Operators, Distributors, and Dispatchers	100	280	
51-8021	Stationary Engineers and Boiler Operators	80	80	
51-8031	Water and Wastewater Treatment Plant Operators	80	330	
51-8091	Chemical Plant and System Operators	20	n.a.	
51-8092	Gas Plant Operators	80	90	
51-8093	Petroleum Pump System and Refinery Operators	740	820	
51-8099	Plant and System Operators, All Other	80	90	
	Equipment Maintenance	**2,350**	**1,020**	**65**
49-9041	Industrial Machinery Maintenance Workers	170	1,020	
49-9042	Maintenance and Repair Workers, General	2,180	n.a.	

Source: CA EDD 2011, HECA 2012a.

Growth Inducing Impacts from Operation of the HECA Component

Staff agrees with the applicant's assumptions about the HECA power plant operations workforce and expects that, at most, 40 percent of operations employees would need to relocate or commute to the project area, given the robust regional workforce. While the project could likely achieve a greater than 60 percent local workforce, the use of the 40 percent non-local figure represents a more conservative, worst-case scenario. Based on this estimate, around 80 workers would relocate to Kern County, translating into a total population increase of over 250 people, based on an average household size of 3.15. Applying this estimate to the gravity model described above, roughly 40 workers and their families, or around 135 people in total, could relocate to the city of Bakersfield. Another 19 people would relocate to Rosedale. Only two workers and their families would relocate to Buttonwillow. This would equal a population increase of only around 0.4 percent. One worker and their family would likely locate in Tupman, which would equal a 2 percent increase in the resident population.

Growth Inducing Impacts from Operation of the OEHI/EOR Component

On page 4.12-6 of Appendix A of the AFC, the applicant indicates that the OEHI EOR component of the HECA project would generate up to 25 full-time operations jobs over its 20-year implementation period. Hiring would likely occur over time, coinciding with build-out. The applicant expects that a majority of these positions would go to existing Kern County residents. Based on the occupational employment estimates, and the unemployment data reported earlier, staff believes that the existing Kern County labor force would be sufficient to accommodate labor demand associated with operation of the EOR component of the project. For analytical purposes, the applicant assumed that all 25 of the operations workers would be non-local and would permanently relocate to Kern County. For this analysis, staff used the same worst-case scenario in which operation of the EOR component would result in the permanent relocation of 25 workers and their families to Kern County.

To estimate the total population change that would occur due to the permanent relocation of worker households, staff first applied the gravity model for migration described above to the total operations workforce estimate of 25 workers. Staff then multiplied the estimated number of workers who would relocate to each community by the average household size for Kern County from the 2010 Census of 3.15. Based on these estimates, the majority of households, around 15 in total, would prefer to relocate to the city of Bakersfield. This would translate into a total of 47 new residents and a 0.01 percent increase in the city's population. The remaining households would relocate to communities located throughout western Kern County, resulting in no greater than a 0.02 percent increase in the population of each affected community.

Growth Inducing Impacts from Operation of the Whole of the Project

To ascertain whether operation of the whole of the project, including both the HECA power plant and the EOR components, would result in substantial induced population growth, staff combined the results of the two gravity models described above. The combined results suggest that of those workers that would relocate to the project area during the initial construction period (i.e. the period during which the two construction schedules would overlap), around 55 percent would prefer housing in the city of Bakersfield. This could equal around 60 workers, resulting in a temporary increase in the city's population of up to 0.05 percent, if workers are assumed to relocate with their families. The remaining 45, or so, households would relocate to communities located throughout western Kern County, resulting in no greater than a 0.2 percent increase in the population of each affected community. Tupman could be the only exception to this trend, wherein the relocation of one household could increase the population by around 2 percent.

Displace Existing Housing and Substantial Numbers of People, Necessitating the Construction of Replacement Housing Elsewhere

Socioeconomics Table 10 reports data on the existing housing stock in the project area and Kern County, including data for the two effected CCDs. As of April 1, 2010, there were around 406 housing units in Buttonwillow, 144 in Derby Acres, 73 in Tupman, and 193 in Valley Acres. This equaled 816 housing units located in urban areas within the project buffer area. Around 10 percent of those units were vacant, equal to 84 total units. Note that the vacancy rates in Buttonwillow and Valley Acres were only 7 percent and 9 percent, respectively. By comparison, vacancy rates in Derby Acres and Tupman were equal to around 15 percent and 25 percent. Around 20 units in the buffer area were reported for-rent, while 12 units were listed for-sale.

Socioeconomics Table 10
Housing Supply and Vacancy Status

Area[1]	Total	Occupied		Vacant		For Rent	For Sale	Other[2]
		Number	Percent	Number	Percent			
Buffer Area	816	732	90%	84	10%	20	12	52
Buttonwillow CDP	406	379	93%	27	7%	9	3	15
Derby Acres CDP	144	123	85%	21	15%	6	7	8
Tupman CDP	73	55	75%	18	25%	3	0	15
Valley Acres CDP	193	175	91%	18	9%	2	2	14
Bakersfield	120,725	111,132	92%	9,593	8%	4,428	2,187	2,978
Dustin Acres CDP	252	224	89%	28	11%	2	9	17
Fellows CDP	40	37	93%	3	8%	0	1	2
Ford City CDP	1,426	1,260	88%	166	12%	36	18	112
Maricopa	466	414	89%	52	11%	16	5	31
McKittrick CDP	46	42	91%	4	9%	1	0	3
South Taft CDP	733	606	83%	127	17%	33	0	94
Taft city	2,525	2,254	89%	271	11%	108	37	126
Taft Heights CDP	776	674	87%	102	13%	35	14	53
Wasco	5,477	5,131	94%	346	6%	103	143	100
Kern County	284,367	254,610	90%	29,757	10%	9,743	5,072	14,942
Buttonwillow CCD	1,137	1,034	91%	103	9%	12	14	77
West Kern CCD	12,181	9,670	79%	2,511	21%	361	229	1,921

Notes: [1]CDP - Census Designated Place and CCD - Census County Division; [2]Other includes units that are rented or sold, but not occupied, as well as units that are vacant due to recreational or occasional use, use by migratory laborers, and units that were vacant for other miscellaneous reasons.
Source: US Census 2010c.

More than 50 additional units were vacant due to occasional use, use by migratory laborers, or were vacant for other reasons.

Outside the buffer area, the city of Taft had 2,525 housing units, of which 11 percent were vacant. Of those 271 total vacant units, 108 were for-rent and another 126 were for-sale. When combined with the communities of South Taft, Taft Heights, and Ford City, the greater Taft area had a total of 5,460 housing units. Of these, 666 were reported vacant, which equals a vacancy rate of 12 percent. Roughly 212 units were reported for rent in the area and another 69 units reported for-sale, with an additional 385 units vacant for other reasons. The city of Wasco had 5,477 housing units, of which 6 percent were vacant. Of the 346 total vacant units, 103 were for-rent and another 143 were for-sale. The city of Bakersfield had 120,725 housing units in 2010. With a vacancy rate of roughly 8 percent, Bakersfield had 9,593 vacant units. Of those, 4,428 units were for-rent and 2,187 were for-sale, with another 2,978 units vacant for other reasons. Kern County had 284,367 units, with a vacancy rate of 10 percent. This equaled 29,757 vacant housing units, including 9,743 rental units and 5,072 for-sale units.

As many construction workers are likely to commute to the project area on a daily or weekly basis, staff also investigated the availability of temporary housing options. According to the Bakersfield Convention and Visitors Bureau, there are around 5,400 hotel rooms in the city of Bakersfield, another 600 in surrounding communities, and 196 rooms in Buttonwillow (CEC 2012b). For the 2011 calendar year, the average occupancy for these rooms was around 63 percent. This translates to an average of 3,900 occupied rooms, with around 2,300 vacancies. A report by Smith Travel Research estimated that there are nearly 10,000 hotel rooms at 128 properties in the greater Bakersfield metropolitan area (STR 2012). The report estimates an average nightly occupancy rate of 65 percent from January through June of 2012, up from 60 percent for the same period a year earlier. Based on these estimates, there would be more than sufficient temporary housing to accommodate workers seeking to commute to the project on a weekly or semi-weekly basis.

To identify the available accommodations for temporary construction workers that might prefer to camp, rather than rent a hotel room, staff identified a variety of recreational vehicle (RV) and primitive camping options. **Socioeconomics Table 11** identifies 10 RV parks located near the cities of Bakersfield and Taft. These facilities offer over 1,000 sites with electrical hookups and waste disposal facilities. The Kern County Department of Parks and Recreation also operates five campground facilities in the unincorporated area (Kern County 2012a). The Buena Vista Aquatic Recreational Area is located only 7.5 miles southeast of Tupman. It offers 112 campsites and allows up to 15 people per site. Kern River Campground located northeast of Oildale has 50 campsites and allows eight people per site. While located some distance from the project site, the Tehachapi Mountain Park offers 61 family campsites and two group facilities. The Tehachapi Mountain Camp accommodates a minimum of 40 persons and the Sierra Flats Camp can accommodate up to 150 persons. The Greenhorn Mountain Park located 50 miles to the northeast of Bakersfield has 70 family campsites and two group facilities that can accommodate a combined total of 175 people. Of the four state parks located in Kern County, only Red Rock Canyon State Park in the far eastern corner of the county offers

50 primitive campsites with no RV hookups. Based on this information, staff estimates that there would be sufficient resources available to accommodate those construction workers who would prefer camping to other forms of accommodation.

Socioeconomics Table 11
Sample Inventory of Recreational Vehicle and Mobile Home Sites

Name	Street Address	City	Number of Sites
A Country RV Park	622 S. Fairfax Rd.	Bakersfield	120
Bakersfield Palms RV Park	250 Fairfax Rd.	Bakersfield	25
Bakersfield RV Resort	5025 Wible Rd.	Bakersfield	215
Bakersfield RV Travel Park	8633 E. Brundage Ln.	Bakersfield	100
Bear Mountain RV Park	16501 S. Union Ave.	Bakersfield	131
Buena Vista Mobil Home Park	123 N. 10th St.	Taft	n.a.
Orange Grove RV Park	1452 S. Edison Rd.	Bakersfield	177
River Run RV Park	3715 Burr St.	Bakersfield	123
Rosedale Village RV Park	13901 Rosedale Hwy.	Bakersfield	156
Suncrest Village RV Park	2555 Jewetta Ave.	Bakersfield	41

Displacement Impacts from Construction for the Whole of the Project

Compared to the worker relocation estimates described above, staff estimates that the existing housing stock in the project area would be sufficient to accommodate demand for housing generated by construction of the whole of the proposed project. For example, if staff assumes that 40 percent of the construction workforce for the HECA component, and 25-75 percent of the construction workforce for the EOR component, would be non-local, the project area would need to absorb a maximum of around 1,250 workers and their families during the project construction period. According to data from the Decennial Census, the city of Bakersfield alone could absorb nearly 9,600 households in a combination of rental and for-sale housing, and over 4,400 households in rental housing alone. Thus, the available housing supply within one-half hour of both the HECA and OEHI EOR project sites would be more than sufficient to accommodate the non-local project labor force.

The gravity model developed by staff suggests that a maximum of around 60 households may prefer to locate in communities in the buffer area during construction. While census data indicate that there were around 84 vacant housing units within the four constituent communities, roughly 50 of them were vacant for reasons other than being for-rent or for-sale. This suggests that those 50 units may not be available for occupancy by households associated with the proposed project. However, due to the preponderance of available housing in and around the cities of Bakersfield and Taft, it is likely that these households would be able to find sufficient accommodation in other nearby communities. As a result, staff does not anticipate that project construction would result in displacement of existing housing or substantial numbers of people, necessitating the construction of replacement housing.

Displacement Impacts from Operation for the Whole of the Project

Furthermore, staff estimates that the existing housing stock in the project area would be sufficient to accommodate demand for housing generated by the whole of the proposed project, once in full operation. Based on the applicant's assumption that 40 percent of the HECA power plant workforce, and 100 percent of the EOR operations workforce, would be non-local, around 105 households could relocate to the project area. The gravity model indicates that around 60 households would relocate to the city of Bakersfield, which could easily be accommodated by the available housing stock. Likewise, two households could relocate to Buttonwillow and one to Tupman. Even with limited housing availability in these two communities, the introduction of these new households would be insufficient to displace the existing population and would not necessitate the construction of new or replacement housing.

Result in Substantial Physical Impacts to Government Facilities

As discussed under the subject headings below, the HECA project would not cause significant impacts with regard to service ratios, response times, or other performance standards associated with law enforcement, education, and parks and recreation facilities. The systems and procedures proposed by the applicant to provide occupational safety and health protection for project employees are discussed in the **Worker Safety and Fire Protection** section of this document.

Law Enforcement

The HECA power plant site and EOR processing facility site are located within the jurisdiction of the Kern County Sheriff's Office. Staff contacted the Kern County Sheriff's Office to discuss the proposed project components, ascertain their ability to provide law enforcement services to the project, and to solicit comments or concerns they might have about the project. Communications with Lieutenant Steve Hansen, Sergeant Marc Haiungs, and Sergeant Martin Downs indicated that the two substations located in Buttonwillow and Taft would provide direct services to the two project sites (CEC 2012c). The boundary between the service areas of the two substations roughly corresponds to the course of the California Aqueduct. Subsequently, the HECA power plant site would be served primarily by the Buttonwillow substation, while the OEHI EOR operation would be served by the Taft substation.

The North County Substation in Buttonwillow is the closest station to the proposed HECA power plant site at approximately 10 miles and would be the most likely to provide direct service to the site. The station covers a service area of 1,500 square miles and is staffed by 13 sworn deputies and two civilian clerks. The response time to the power plant site would be between 10 and 40 minutes for priority calls and 15 to 60 minutes for non-priority calls. The range of response times is due to variation in where deputies would respond from. Deputies would not typically respond from the substation, as they are usually on-patrol elsewhere in the service area.

The Taft Substation is located 20 miles from the HECA power plant site and 13 miles from the OEHI EOR CO_2 processing facility site (CEC 2013c). The substation serves an area of roughly 790 square miles. Existing staffing includes 11 deputies, two detectives, one sergeant, and one office clerk. There are currently two vacancies for Deputy Sheriff positions at the Taft Substation. At current staffing, the station provides approximately one deputy per 1,500 residents. The response time from the Taft substation to the power plant site would be between 15 and 25 minutes for priority calls and 25 to 35 minutes for non-priority calls. Response times to the processing facility site would be between 10 and 15 minutes for priority calls and more than 20 minutes for non-priority calls.

The Sheriff's Office indicated that oil field and rural crime is prevalent in the project area. This places both components of the project at risk for vandalism and theft, particularly during the construction phase. While this could create a need for extra patrols by on-duty deputies and would require deputies to conduct theft and vandalism investigations, the overall increase in demand for law enforcement services would be negligible. The Sheriff's Office also identified potential impacts on traffic circulation during periods of heavy construction activity. The main point of concern would be on Highway 119, which is a two-lane road connecting Interstate 5 and city of Taft. The Sheriff's office does not anticipate significant traffic impacts resulting from project operation. Other concerns voiced by law enforcement include the vulnerability of the power plant and EOR facilities, including the CO_2 pipeline, to terrorist attack. Protests and demonstrations related to climate change could also occur due to the project. Sergeant Downs expressed significant concern over the possible exposure of Sheriff's Deputies to dangerous gases, such as carbon dioxide. Recommended mitigation measures to be implemented that could further reduce the impact on law enforcement from the HECA power plant component include 24-hour private security patrols, chain link perimeter fencing, large motion sensor lights, video monitoring and recording systems, and alarm systems (CEC 2012c). Suggested mitigation measures for the OEHI EOR component include private security patrols, security fencing, good lighting, and the securing of costly equipment and materials (CEC 2013c). The **Hazardous Materials Management** section of the PSA includes recommended Condition of Certification **HAZ-6** addressing security provisions for construction and operation of both project components. With mitigation, the project would not necessitate the provision of new or physically altered law enforcement facilities or the recruitment of additional law enforcement personnel.

The California Highway Patrol (CHP) is the primary law enforcement agency for state highways and roads. The agency is predominately concerned with traffic safety, motoring services, and protection of state property. The CHP does not have the legal authority to be the lead agency for general law enforcement and does not contract for general law enforcement duties. When appropriate, CHP officers can provide law enforcement assistance, if the Kern County Sheriff's Department requests such aid. Both project sites are located within the Central Division District. The closest CHP office is located around 3.5 miles east of the power plant site at 2944 Stockdale Highway at the Interstate 5 interchange. Staff contacted the Buttonwillow Office of the CHP to discuss the proposed project and ascertain their ability to provide traffic and motor vehicle law enforcement services to the project area (CEC 2012d, CEC 2013d). The office is currently staffed with one lieutenant commander, three sergeants, 31 officers, and four civilian staff. The estimated response time to the power plant site for priority calls would be between five and 10 minutes. For non-priority calls, the response time would be between 10 and 20 minutes. Response times to the CO_2 processing facility site would be roughly the same. CHP anticipates that response times could be affected by increased traffic congestion. The project could also result in additional traffic incidents, collisions, and violations. CHP anticipates, however, that the impact on CHP facilities, equipment, and staffing needs would be minimal (CEC 2012d, CEC 2013d).

Based on multiple communications with affected local law enforcement agencies, and the suggested mitigation measures described above, staff concludes that the project would not necessitate the alteration of existing law enforcement facilities, the construction of a new police substation, or the hire of additional law enforcement officers. Thus, the project would have a **less than significant impact on law enforcement**.

Education

Both the power plant and CO_2 processing facility sites are located in the Elk Hills Elementary (EHESD) and the Taft Union High (TUHSD) school districts. The EHESD provides kindergarten through eighth grade education to approximately 140 students at the Elk Hills Elementary School located in Tupman, which represents the school's primary service area (CEC 2012e). The school has nine regular education classrooms and one intervention/resource class. The TUHSD, by comparison, is a comprehensive four-year secondary school that offers ninth through 12th grade education to around 1,060 students (CEC 2012f). The district serves nine communities. These include Derby Acres, Dustin Acres, Fellows, Ford City, McKittrick, South Taft, Taft, Taft Heights, Tupman, and Valley Acres. It operates three campuses including Taft Union High School, Buena Vista High School, and Westside Independent Study High School. Buena Vista High is a small independent study program that houses roughly 120 students. Westside Independent Study High is an adult opportunity program affiliated with the Westside Regional Occupational Program (WSROP). In addition to the EHESD and TUHSD, portions of the EHOF are also located in, or near, the Belridge, Buttonwillow Union, McKittrick, Midway, and Taft City elementary school districts, as well as the Kern Union High School District.

Socioeconomics Table 12 presents data on enrollment, average pupil-to-teacher ratio, and average classroom size for schools located in the EHESD and TUHSD, as well as for other school districts in the project area. As of the 2011-2012 academic year, the EHESD had nine full-time equivalent teachers, a pupil-to-teacher ratio of 21, and an average classroom size of 13 students. The TUHSD schools had around 72 full-time equivalent teachers, a pupil-to-teacher ratio of 14.5, and an average classroom size of around16 students. The majority of students in the TUHSD were located at the Taft Union High School, which had around 960 students, 66 full-time equivalent teachers, a pupil-to-teacher ratio of 14.5, and an average classroom size of around 17. Roughly 80 additional students were enrolled in the Buena Vista continuation program, which had six full-time equivalent teachers, a pupil-to-teacher ratio of 13.3, and an average classroom size of only seven students.

Socioeconomics Table 12
Enrollment and Staffing by School District (2011-2012)

School District	2011-2012 Enrollment	FTE Teachers	Pupil-to-Teacher Ratio	Ave. Class Size
Belridge Elementary	32	3	10.7	3.6
Buttonwillow Union Elementary	373	21	17.4	11.0
Elk Hills Elementary	200	9	21.1	13.4
Kern Union High	37,505	1,572	23.9	23.2
McKittrick Elementary	74	5	14.8	8.2
Taft City Elementary	2,107	100	21.1	21.5
Taft Union High School District	1,042	72	14.5	15.6
Buena Vista High (Continuation)	80	6	13.3	7.0
Non-Public (Independent)	2	n.a.	n.a.	n.a.
Taft Union High	960	66	14.5	17.4
Kern County, All Districts	**175,835**	**7,760**	**22.7**	**23.6**

Source: CDE 2012.

Impact of Construction on Schools

Based on the assumption that 25 to 40 percent of the construction workforce for the HECA power plant component would be non-local, staff estimates that up to 17 worker households could relocate to Tupman during peak construction. To estimate the number of school age children associated with these households, staff used an estimate of the average number of children, ages five to 17, per household in Kern County from the 2010 Decennial Census. Based on these figures, the EHESD could receive up to 12 new students during the project construction phase. At 2011-2012 staffing levels, this would increase the pupil-to-teacher ratio from 21 to 23, and the average class sizes from 13 to 14 students. The District Superintendent for the EHESD indicated that the school works to maintain a maximum pupil-to-teacher ratio of 20 to 1 for the lower grade levels and 25 to 1 for the higher grades (CEC 2012e). The district was out of conformity with these standards in the 2010-2011 school year, but reportedly came back into conformity in the 2011-2012 school year. The superintendent noted that Elk Hills is a "District of Choice" which means that parents located outside of the district can apply to have their child admitted to the district. The district currently transports 155 students by bus from outside of the district. While the majority of these students come from the Taft area, at least one bus currently serves families located in and around Buttonwillow, Rosedale, and Bakersfield. The school's choice status is significant, because in the event that project induced population growth in Tupman were to push the pupil-to-teacher ratio out of conformity with the accepted standard, the school would be required to accept the new local students and to reassess the number of seats made available to out-of-district students. While this could preclude some out-of-district students from attending the EHESD, it lessens the likelihood that project induced population growth would necessitate the construction of new school facilities.

Using the same gravity model and conversion factors described above, staff estimates that up to 75 worker households associated with construction of the HECA power plant component could relocate to communities within the TUHSD. This could equal up to 54 new school age children. If all of these children were to enter the TUHSD system, at 2011-2012 staffing levels, the pupil-to-teacher ratio would remain essentially unchanged, going from 14 to 15. Likewise, the average classroom size, district wide, would only increase from 15 to 16 students. According to a representative from the TUHSD, the district lost 10 teachers during the past year and has only filled two of the vacant positions (CEC 2012f). The district expects to leave the remainder unfilled, as the district is in a deficit and currently has excess staff capacity. With pupil-to-teacher ratios in the mid-teens, the district is well below its maximum pupil-to-teacher ratio of 30, as set forth in the district's labor agreement. Staff concludes that induced population growth associated with the HECA power plant component of the proposed project would not constitute a substantial increase in the school age population within the EHESD and TUHSD, and that the construction of the proposed facilities would not necessitate the provision of new or physically altered facilities.

During construction, staff and the applicant expect the majority of the workforce necessary for construction of the OEHI EOR facilities, including the CO_2 processing site and ancillary facilities, would be existing OEHI employees and contractors. Staff estimates that up to 240 additional workers could be required during peak construct, although most of these would come from within Kern County. Due to fluctuations in the number of workers required for construction of the EOR project facilities, staff anticipates that most of the non-local workers would likely commute on a daily or weekly basis to the project area. It is therefore unlikely that workers would relocate with their families. As a result, staff does not anticipate a significant adverse impact to the Kern County schools from construction of the EOR component of the proposed project.

Impact of Operations on Schools

Staff assumes that 40 percent of the 200 full-time workers needed to operate the HECA power plant would relocate from outside of Kern County. This would translate into 80 new worker households. Staff estimates that of the 80 workers that would relocate to Kern County, only one worker household would likely relocate to Tupman during the project operations phase. This could result in the introduction of up to one additional student to the EHESD. Likewise, staff estimates that up to three worker households could relocate to communities within the TUHSD, possibly introducing up to three new students to the TUHSD system. The possible addition of one to three students to the EHESD and TUHSD systems, given existing enrollment and staffing levels, would not constitute a substantial increase in the school age population and, by extension, would not necessitate the provision of new or physically altered facilities in order to maintain acceptable service ratios.

The applicant anticipates that operation of the EOR component would generate up to 25 full-time jobs, maintained over the 20-year implementation period. A majority of these workers would be existing Kern County residents. For analytical purposes, the applicant assumed that all 25 workers would relocate into Kern County with their families. To estimate the number of school age children associated with these households, staff used an estimate of the average number children, ages five to 17, per household in Kern County of 0.71 from the 2010 Decennial Census. This would translate into around 18 new school age children. The majority of these, around 11 in total, would likely reside in the city of Bakersfield and would attend schools in that area. The remaining households would relocate to communities throughout western Kern County, resulting in the addition of one or two school age children in each affected community. Based on these estimates, and those reported above, staff concludes that project induced population growth would not constitute a substantial increase in the school age population and that the project would not necessitate the provision of new or physically altered school facilities. Therefore, the project would have a **less than significant impact on schools**.

Parks and Recreation

In addition to the Kern County Parks and Recreation Department, there are many different cities, independent park districts, and state and federal agencies, that provide parkland and recreational facilities for use by Kern County residents. Although the project site is located in an area of unincorporated Kern County served by the County Parks and Recreation Department, the majority of the impacts on parks and recreation facilities would occur in and around incorporated communities, such as the city of Bakersfield, due to project induced population growth. To assess the likelihood and severity of project related impacts on parks and recreation facilities, staff utilized the results of the gravity model for migration to identify those park districts that would experience the greatest induced population growth. For each park district, staff identified existing service standards and inventoried existing facilities and park acreages. Staff used Geographic Information Systems (GIS) to estimate the existing population located within each parks district based on census block estimates from the 2010 Decennial Census. The existing and planned park facility inventories were then compared to the population estimates to assess whether induced population growth would result in a breach of service standards. **Socioeconomics Table 13** reports the 2010 population and existing park acreages for the seven parks districts that would be most affected by project induced population growth.

According to the Kern County Parks and Recreation Master Plan (Kern County 2010), the goal of the county is to provide a total of five acres of parkland per 1,000 residents. The minimum service standard according to the Kern County General Plan is 2.5 acres per 1,000 residents (Kern County 2009). While most of the affected park districts, such as the Wasco Recreation and Parks District, have no formally adopted service standard, many already conform to the 2.5-acre standard. Some districts, such as the Westside Recreation and Parks District, have adopted standards that are lower than the existing county minimum. According to the data provided in **Socioeconomics Table 13**, four of the seven affected parks districts are currently in compliance with the minimum county service standard. These include the Buttonwillow Recreation and Parks District, the North Bakersfield River Recreation and Parks District (also known as the North of the River Recreation and Parks District), the Wasco Recreation and Parks District and the Westside Recreation and Parks District. The city of Bakersfield appears slightly out of compliance with the existing county standard with a total of 700 acres of dedicated parkland. This equals an estimated 2.4 acres per 1,000 residents. However, in addition to the 700 acres of dedicated parkland, the city also maintains an estimated 700 acres of public medians and other landscaping that, if included, would bring the ratio to 4.9 acres of open space per 1,000 residents. There are no adopted service standards in the McFarland and Shafter Recreation and Parks District.

Socioeconomics Table 13
Park Acreage in Select Districts

Park and Recreation Department/District	2010 Population	Park Acreage	Acres per 1,000 Persons
Buttonwillow	2,130	20	9.4
Bakersfield	347,483	700	2.4
McFarland	13,560	25	1.8
North Bakersfield[1]	128,270	317	2.5
Shafter	19,620	30	1.5
Wasco	26,290	72	2.7
Westside	20,040	50	2.5

Note: [1]The North Bakersfield Recreation and Parks District (also known as the North of the River Recreation and Parks District) serves part of the city of Bakersfield and parts of unincorporated Kern County.

To assess whether induced population growth would result in a breach of service standards, staff added the induced population estimates for the communities located within each park district to the existing 2010 Decennial Census estimates. The greatest estimated increase in population would occur in the Buttonwillow Recreation and Park District, which would experience up to a 3.5 percent increase in its service population. The Shafter, Wasco, and Westside districts would each experience an increase in their service populations of roughly 1 percent. The Bakersfield, McFarland, and North Bakersfield districts would experience increases of less than 1 percent. Based on these estimates, staff concludes that project induced population growth would be insufficient to appreciably reduce the ratio of park acreage to population in any of the seven affected parks districts. The project would therefore have a **less than significant impact on parks and recreation facilities**.

CUMULATIVE IMPACTS AND MITIGATION

According to CEQA Guidelines, proposed projects can have cumulatively considerable effects on the environment, even when the project has anticipated environmental impacts that are independently less than significant. This means that the incremental contribution of a project can still be significant, when viewed in conjunction with other past, present, and probable future projects. An analysis of potential cumulative impacts should identify the likelihood that cumulative effects would occur, and if so, determine the potential severity of those effects. The cumulative analysis does not require the same level of detail provided for the impacts of the proposed project alone. Staff is simply required to make all practical and reasonable efforts to discover, disclose, and discuss related projects, as they pertain to the impacts in question. Even when staff identifies a significant cumulative impact, the project’s incremental contribution can be less than cumulatively considerable, if the project implements all measures necessary, and feasible, to avoid, or substantially reduce, the project’s cumulative effects [Public Resources Code Section 21083; California Code of Regulations, Title 14, Sections 15064(h); 15065 (c); 15130; and 15355].

Staff evaluates cumulative socioeconomic impacts based on the above guidance, using the thresholds of significance identified in Appendix G of the CEQA Guidelines. For assessment of cumulative impacts to emergency medical services and response times, please refer to the section on **Worker Safety and Fire Protection**. For socioeconomics, cumulative impacts can occur when multiple projects within the same labor market area have overlapping construction schedules. If cumulative labor demand is greater than the existing and projected local labor supply, projects would need to rely, to a greater extent, on other non-local labor sources. The resulting influx of non-local workers and their dependents, whether relocating temporarily or permanently, can place a strain on local housing, public services, and recreation facilities.

Due to the proposed location of the HECA project site, staff identified Kern County as the area most likely affected by cumulative socioeconomic impacts. The Bakersfield-Delano Metropolitan Statistical Area, defined to include Kern County and its constituent communities, represents a reasonably cohesive market area for housing and public services. As such, non-local workers relocating, temporarily or permanently, to participate in project construction or operation, would likely reside within this area. Non-local labor, which staff anticipates could account for up to 40 percent of the total workforce, would likely originate from one of six surrounding counties, including Fresno, Inyo, Kings, Los Angeles, San Bernardino, and Tulare. Staff defined this labor market area based on the information reported in the AFC, the industry standard one- and two-hour commute sheds for operation and construction labor, and through conversations with the BTC for Kern, Inyo, and Mono counties. While the cumulative analysis reported in the AFC uses a list of projects located within six-miles of the project site, staff believes this area is too small and is not representative of the local labor market area.

Socioeconomics Table 14 lists the projects considered as part of the HECA power plant cumulative scenario, from a socioeconomic resources perspective. Staff compiled the list based on environmental reports and notices submitted to the state clearinghouse. Staff also reviewed planning and environmental documents available on city and county websites and contacted local planning agencies. As of November 2012, the BTC for Kern, Mono, and Inyo counties was unaware of any projects planned, proposed, or under development in the region that could have an impact on labor availability for both the HECA power plant and OEHI EOR components (CEC 2013e). According to the BTC, most small-scale projects can be excluded from the cumulative list due to their relatively short construction schedules and small labor force requirements. Construction workers and contractors typically give preference to projects with longer construction schedules and larger workforce requirements, as these provide more stable employment opportunities. The cumulative impacts of multiple small-scale developments, if any, would be of low severity and short duration. Most residential and commercial development projects can also be excluded. They require less skilled labor that is easily supplemented by existing apprenticeship programs. These projects also rely on non-union labor, meaning that they draw on labor supplies that are distinct and separate (i.e. not represented by participating local unions) from those utilized for the HECA project.

Socioeconomics Table 14
Cumulative Project List for Socioeconomics

Project Name	Location	Description
Abajo Transmission	Kern County	Installation of 18-inch diameter pipeline along Abajo Avenue connecting Sage Land and Santa Lucia water tanks.
Barren Ridge Transmission	Kern County; Los Angeles County	Expansion of Barren Ridge Switching Station; and construction of Haskell Canyon Switching Station; construction of 230 kV transmission lines and reconductoring of existing lines.
Berry Petroleum Steam Injection	Kern County	Construction of cyclic steam injection facilities for enhanced oil recovery.
Biodiesel Refinery	City of Fresno	Three phase construction of industrial biodiesel refining facility.
Borax Co-gen Plant Replacement	Kern County	Construct replacement co-generation plant with two natural-gas-fired turbine generators and steam recovery system.
California High Speed Rail	Fresno County; Kern County; Los Angeles County	Construction of dedicated, electrified high-speed rail system. If developed, Merced to Palmdale sections may utilize area labor.
Calnev Pipeline Expansion	San Bernardino County	Construction of a new 233-mile 16-inch diameter pipeline.
Crystal Geyser Bottling Plant	Inyo County	Construct water-bottling facility with associated warehouse and 8.3-acre solar photovoltaic power array.
Fremont Valley Preservation	Kern County	Construction of tertiary wastewater treatment and disinfection facility.
Fresno Tertiary Water Treatment	City of Fresno	Construct tertiary wastewater treatment and disinfection facility.
Lehigh Alternative Fuels	Kern County	Install equipment necessary to use alternative fuels to provide heat for cement production.
Liberty Energy Center	Kern County	Construct 19.5-megawatt gasification facility to supplement existing composting operation.
Northern Area Water	Kern County	Convert 18-miles of earthen canals to 25-miles of pipeline in Buttonwillow Service Area.
Red Rock Bridge Replacement	Kern County	Replace existing bridge on SR 14 at Red Rock Canyon Wash.
Sierra View Hospital Laboratory	City of Porterville	Construct new hospital laboratory facility.
Tulare County Sherriff Detention Facility	Tulare County	Construct new Tulare County detention facility.

Sources: Fresno County 2012, Kern County 2012b, Kern County 2012c, Kern County 2012d, OPR 2012.

In addition to the projects listed below, staff identified 132 solar photovoltaic power projects and 11 wind power projects that are planned, proposed, or under development in the defined labor market area. Over half of the solar projects are proposed in Kern County, while the remaining projects are primarily in Fresno County. The photovoltaic projects range in size from one megawatt or less, to over 1,000 megawatts, in the case of the Kern Solar Ranch project. The majority of the proposed wind power projects are located in eastern Kern County. They range in size from 40 to 750 megawatts. Given the unique labor force requirements of these projects, staff does not expect substantial overlap with the HECA project. Construction of photovoltaic power projects mostly requires general construction labor, with limited usage of electricians for installation of power inverters and essential wiring. Wind projects, by comparison, require general laborers, crane operators, and workers who have received special training on the installation of wind turbine generators. In the event that a local labor shortage were to occur among workers in these occupational categories, the Kern Community College District has partnered with the Clean Energy Center to offer training and certification for construction laborers and electricians on the handling and proper installation of photovoltaic and wind power systems (Energy Center 2012).

Staff identified a total of 17 industrial, infrastructure, and natural resource projects with labor needs that could potentially overlap with those of the HECA power plant component. Where possible, staff collected information on anticipated construction schedules and workforce requirements. As discussed earlier, construction of the HECA power plant component would take approximately 49-months, beginning with pre-construction activities in September of 2013. The number of workers required for the project would increase gradually from only 34 workers during pre-construction to 2,461 at peak employment. In month-32 of project development, the number of construction workers would begin to decline, corresponding to an increase in the number of commissioning and operating staff. Although it is likely that some of the cumulative projects listed would break ground during the HECA power plant construction period, staff does not anticipate that these labor demands would overly conflict with those of the HECA project, such that the applicant could not achieve 60 percent or greater local employment during construction of the power plant component of the proposed project.

The primary basis for the above conclusion is the high unemployment rate and large number of unemployed residents in Kern County. As of November 2012, the county had an unemployment rate of 12.4 percent and around 47,400 residents without work. While this was an improvement over the 15.9 percent unemployment rate experienced in March of 2012, or the 17.8 percent rate from March 2010, it remains substantially higher than the state average in November of 9.6 percent (CA EDD 2012). Anecdotal evidence suggests that unemployment remains a problem among construction craft workers of various types, with Kern County workers commuting to Los Angeles County, and elsewhere, to find work (CEC 2013e). Although the applicant may face labor shortfalls in some key occupational categories (i.e. boilermakers), the gradual increase in employment levels anticipated during project construction should allow participating unions to locate and train prospective workers through existing apprenticeship programs and the community college system.

In summary, **Socioeconomics Tables 5** and **6** report that the labor force in Kern County would be more than sufficient to accommodate the HECA power plant component of the proposed project. For the reasons described above, none of the cumulative projects identified would likely constrain labor availability for the proposed HECA project, beyond the assumed 60 percent local hiring assumption. The estimates of housing availability reported in **Socioeconomics Table 10** shows a vacancy rate of more than 10 percent, and over 14,800 housing units for sale or rent in Kern County. As a result, staff does not anticipate that induced population growth, resulting from both of the proposed project components, as well as other cumulative developments, would constrain local housing availability. Because the provision of public services is tied to new housing development, staff believes that the introduction of new households, who would occupy existing housing units, would not place undue strain on area services and infrastructure. Staff, thereby concludes, that the construction of the HECA power plant component of the proposed project would not result in any significant and adverse cumulative socioeconomic impacts on population, housing, schools, parks and recreation, or law enforcement.

As discussed earlier, the applicant anticipates that around 75 percent of the labor required for the well and pipeline installations necessary for the EOR component of the proposed project would be employees or contractors already working on behalf of OEHI. Another 25 percent of the labor required for construction of the processing facility and satellite stations would come from the existing OEHI workforce. Based on these estimates, staff estimates that the project would require a maximum of 240 additional workers, beyond those already employed or contracted with OEHI. For the purpose of this socioeconomic impact assessment, staff assumes that all of the 240 additional non-OEHI workers would be non-local and would commute to the project area on a daily or weekly basis. The project would also require up to 25 workers for operation of the EOR facilities. While the applicant anticipates that most of these workers would come from within Kern County, the impact analysis assumes a worst-case scenario, in which these workers would be non-local and would permanently relocate, with their families, to communities within Kern County. As described above, staff was unable to identify any projects with the potential to increase reliance on non-local workers. Therefore, none of the projects considered together with the HECA power plant and EOR operation would create cumulative impacts with regard to labor supply. Staff, thereby, concludes that the proposed OEHI EOR component of the proposed project would not result in any significant and adverse cumulative impacts on population, housing, schools, parks and recreation, or law enforcement.

NOTEWORTHY PUBLIC BENEFITS

For the purpose of this analysis, staff defines noteworthy public benefits to include the changes in local economic activity and tax revenue that would result from project construction and operation. The anticipated economic impacts of proposed projects are typically estimated using quantitative economic models. The economic model most commonly used is the IMPLAN input-output model, developed by the Minnesota IMPLAN Group (MIG). The model relies on complex input-output tables and social accounting matrices. These are quantitative representations of the purchaser-supplier relationships between producers, and intermediate and final consumers. Based on these tables, the analyst can estimate the economic activity that would result from a given expenditure, or other economic event. The resulting economic impact estimates are divided into three categories. These are the Direct, Indirect, and Induced economic impacts. Within each of these categories, the model estimates associated changes in employment, labor income, and economic output.[8] Direct economic effects represent the

[8] The Minnesota IMPLAN Group (2012) defines Economic Output as “the value of industry production.” In the manufacturing sector, output is equal to total sales, minus inventory changes. For the

employment, labor income, and spending associated with construction or operation of the project itself. Indirect economic effects represent the expenditures on intermediate goods made by suppliers who provide goods and services to the project. Induced economic effects represent household spending that occurs due to the increased wages, salaries, and proprietor's income generated in the direct and indirect rounds.

There are several important caveats to note with regard to input-output analysis and the IMPLAN model. The purpose of the analysis is to construct a reasonable profile of the project related investments and to demonstrate the overall magnitude and direction of the economic impacts that would accrue to the surrounding economy. The resulting impact estimates do not represent a precise forecast, but rather an approximate estimate of the overall economic effect. The IMPLAN model is a static model, meaning that it relies on inter-industry relationships, institutional spending patterns, and household consumption patterns, as they exist at the time of the analysis. The model assumes that prices remain fixed, regardless of changes in demand, and that industry purchaser-supplier relationships operate in fixed proportions. The model does not account for substitution effects, supply constraints, economies of scale, demographic change, or other structural adjustments. Impact estimates represent gross impacts and do not account for opportunity costs, such as the construction of other types of power generation facilities. The model also does not account for various intangible effects, such as grid reliability or renewable versus non-renewable energy.

One concern when using modeling programs, such as IMPLAN, to estimate the economic impacts of power plant construction and operation, is that the standard industry classifications provided by the software may not be representative of the types of activities that are proposed. For example, Sector 31 in the IMPLAN software represents the average spending pattern for the electrical power generation, transmission, and distribution industry. The details of the industry spending pattern for a given study area depend on what power plants are already located there. As a result, the analyst can expect that the spending pattern for Sector 31 will typically reflect conventional power generation technologies, such as coal and natural gas. For a project like HECA, that uses an innovative hydrogen-based technology, the default spending patterns associated with Sector 31 may not be representative of how the proposed project would actually operate. Likewise, Sector 35 represents the spending pattern associated with construction of new nonresidential manufacturing structures. While the HECA facilities may broadly fall within this category, the IMPLAN sector would more accurately model general manufacturing construction, of the type that might occupy large warehouse type structures. Likely excluded from the default Sector 35 spending pattern are purchases unique to power plant construction, such as natural gas turbines or, in this case, the Mitsubishi Heavy Industries (MHI) dry feed gasifier and 501GAC® generator. Staff was, therefore, careful to evaluate the available information on anticipated project budgets for construction and operation, in order to assess whether the default industry spending patterns will provide reasonably reliable impact estimates.

On pages 5.8-15 through 5.8-18 of the amended AFC, the applicant reports estimates of the direct, indirect, and induced economic impacts of the proposed project, including

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service sectors, output is equal to total sales. In the retail and wholesale trade sectors, output is equal to the gross margin (i.e. total sales, minus the cost of goods sold).

both the HECA power plant and OEHI EOR components, developed using the IMPLAN economic model. The applicant used Kern County as the unit of analysis. The economic data used was from the year 2009 and was presumably the most recent data available at the time of the analysis. Staff requested that the applicant provide a detailed list of assumptions and input values used in the IMPLAN model (CEC 2012g). In Data Response A163 the applicant explained that the primary input used in the model was direct employment, measured by the maximum number of jobs per calendar year (HECA 2012d). The employment estimates include figures for the HECA power plant, the OEHI EOR operation, and the rail spur. The construction scenario used IMPLAN Sector 35. The applicant edited the industry data for this sector to reflect average employee compensation of $85 per hour and a 50-hour workweek. The applicant assumes that 60 percent of the construction labor force would come from Kern County. The applicant extends this assumption to other non-labor construction costs, assuming that 60 percent of the construction materials and supplies would be purchased from within Kern County (HECA 2012a, page 5.8-16). The operations scenario used IMPLAN Sector 31 for Electric Power Generation, Sector 130 for Fertilizer Manufacturing, Sector 20 for Extraction of Oil and Natural Gas, and Sector 333 for Transport by Rail (HECA 2012d). According to the AFC, the applicant assumes that 30 percent of the non-labor expenditures made during project operations would occur within Kern County, while operations labor would be 100 percent local (HECA 2012a, page 5.8-17).

Based on the IMPLAN model specifications described above, the applicant estimated that the total construction cost for the whole of the project would be around $3.15 billion (HECA 2012a, page 5.8-16).[9] The total direct labor costs for construction would equal roughly $1.37 billion. The remaining $1.78 billion includes other non-labor expenditures, such as project engineering and materials procurement. Note that these are gross figures, which do not account for economic leakage.[10] Based on these direct expenditures, the applicant anticipates that the project would generate roughly $843 million in indirect and induced economic output, as well as $294 million in additional labor income (HECA 2012a, page 5.8-17). Note that these are gross estimates, and that some unidentified portion of these benefits would accrue to areas located outside of Kern County.

For operations, the applicant estimated that the project as a whole would generate around $30 million in direct labor income (HECA 2012a, Page 5.8-17). While the AFC does not provide an estimate of non-labor direct spending for operations, the applicant assumes that 30 percent of all materials and supply purchases would occur within Kern County. The indirect and induced impacts of project operations, including both HECA and the OEHI EOR projects, would reportedly include the annual maintenance of 430

[9] Because the applicant used Sector 35 of the IMPLAN model to estimate direct construction costs, rather than using independently derived construction cost estimates, staff is concerned that the applicant's estimates may exclude the costs associated with some high-value, specialized equipment used to construct the Gasification and Power Blocks. Examples include the Mitsubishi Heavy Industries (MHI) dry feed gasifier and 501GAC® generator. While these expenditures would likely occur outside of Kern County, and would therefore not represent a local economic impact, their exclusion may significantly under represent the total value of project construction.

[10] Economic leakage represents the value of expenditures and economic activity that occurs outside of the local area.

jobs, $21 million in labor income, and $68 million in economic output (HECA 2012a, Page 5.8-18). Note, again, that these are gross estimates, which do not account for economic leakage. While the applicant expects a majority of these impacts to accrue to Kern County, some unspecified amount will accrue to areas outside of Kern County.

In order to develop a more comprehensive profile of project related investments, staff requested that the applicant provide more detailed information on anticipated construction and operations costs and employment levels (CEC 2012g). The purpose of this request was to ensure that staff had sufficient information to confirm the accuracy and reliability of the estimates provided by the applicant, or to independently model the economic impacts of the proposed project. To prevent disclosure of proprietary business information, staff encouraged the applicant to submit a request for confidential treatment of the information. In response to staff's initial request, the applicant filed a formal objection (HECA 2012c). Following continued discussions between the applicant and staff, the applicant filed a response under cover of confidentiality (HECA 2012b). However, because the project is only in its preliminary stages, the applicant indicated that much of the requested information is not yet available. Staff, therefore, cannot fully confirm the accuracy or reliability of the economic impact estimates reported in the AFC. Staff can, however, confirm that the economic impacts of the whole of the project, including both the power plant and EOR operation, would represent a substantial economic benefit to Kern County.

PROPERTY TAX

Article XIII, Section 19, of the California Constitution gives the Board of Equalization (BOE) jurisdiction over the assessment of properties owned or operated by electrical corporations. Sections 118, 721, 721.5, and 722.5 of the Revenue and Taxation Code clarify that the BOE is responsible for assessment of electrical generation facilities with capacity of 50 megawatts or more, that are operated by electric corporations or public utilities, as defined in Subsections (a) and (B) of Section 218 of the Public Utilities Code. For electrical generation facilities with capacities of less than 50 megawatts, the assessor's office for the each county is responsible for property tax assessments.

The property tax rates for parcels associated with the construction of the power plant and manufacturing complex are set by the Kern County Auditor-Controller's office. The base rate for Kern County is 1 percent, with an additional percentage levied within certain tax rate areas. The current property tax rate for the power plant site is 1.06 percent (Kern County 2012e). This includes the two parcels with Assessors Tax Numbers (ATNs) 159-040-18-00-2 and 159-040-16-00-6. Both properties are located in the Elk Hills (067-007) Tax Rate Area and neither is subject to any special assessments. The assessed values for the parcels for the 2012-2013 Fiscal Year was around $2.5 million combined (Kern County 2012f). Based on the above tax rate, these parcels have a combined tax liability of just over $26,000.

In the response to staff's Data Request A169, the applicant reported ATNs and property tax rates for the 26 parcels associated with the proposed railroad spur (HECA 2012d). A total of 15 parcels have tax rates of 1.09 percent. One parcel has a rate of 1.07 percent, while the remainder have rates of 1.06 percent. One parcel, ATN 103-100-37-00-7, was reported as an "Assessors Utility Parcel," which is not subject to property taxes (Kern

County 2012f). The total assessed value of the affected parcels for the 2012-2013 Fiscal Year is $8.2 million, with a total tax liability of roughly $92,850.

Various techniques can be used to estimate value and to otherwise assess property for tax purposes. These include the comparable sales approach, replacement cost approach, and capitalized income method, among others. Section 721 of the Revenue and Taxation Code indicates that the BOE follows a policy of valuing public utility properties based on reproduction cost, minus depreciation. However, it has the authority to use other methods as necessary to maintain fairness and uniformity. Reassessment of property takes place when new construction or a change of ownership occurs. For the purpose of this analysis, staff assumes that assessment of the project related properties would occur post-construction and that the value would be determined using the reproduction cost method. Note that the estimates reported below do not represent a formal assessment of property value or property tax liability.

The applicant estimates on page 5.8-16 of the amended AFC that the total cost for project development would equal roughly $3.15 billion. This includes the estimated cost for improvements to the project site, construction of the rail spur, and the first three years of development associated with the OEHI EOR project. For the reasons discussed earlier, staff cannot confirm whether this cost estimate is an accurate or complete representation of the proposed project's development costs. However, for this analysis, staff allocated the total estimated development cost between the two main project components (i.e. HECA power plant and OEHI EOR operation), plus the rail spur, based on the percentage of the construction workforce utilized for each component, to provide an estimate of the amount of property tax revenue that the project might generate. Employment estimates for construction of the HECA power plant were taken from Table 5.8-11 of the amended AFC. Employment estimates for the first four years of construction of the OEHI EOR component were taken from Table 3-4 of Appendix A of the amended AFC. Employment estimates for construction of the rail spur were from Table A163-1 in the applicant's *Responses to CEC Data Requests Set Two*. Based on this distribution, staff estimates that the capital cost attributable to the construction of the HECA power plant would equal roughly $2.6 billion. At the applicable 1.09 percent property tax rate, this would generate nearly $28.7 million in annual property tax revenue. The rail spur, likewise, would account for around $26 million in capital costs, which would translate to between $278,000 and $285,900 in annual property tax revenue. Together, the HECA power plant and rail spur could generate upwards of $28.9 million in annual property tax revenue.

According to the California Department of Conservation (CDC), the State of California does not levy severance taxes on oil and natural gas production (CDC 2012a). The state does levy an assessment on the value of oil and natural gas produced. The Oil and Gas Assessment rate for fiscal year 2012-2013 is 14.06207 cents per barrel of oil or 10 million cubic feet (Mcf) of natural gas produced (CDC 2012b). An increase in the amount of oil produced due to implementation of the EOR project would correlate to an increase in the assessed value of oil and natural gas production and in the revenues received by the CDC's Division of Oil, Gas, and Geothermal Resources.

Kern County also levies ad valorem taxes on property used for oil and natural gas production. Staff used parcel data to identify the Assessor's Parcel Numbers (APNs) and property tax rates for parcels located within the EHOF (Kern County 2012e). According to the assessor's records, 2012-2013 tax rates for properties in the EHOF range from 1.03 to 1.09 percent (Kern County 2012d). The AFC does not identify the Assessor's Parcel Numbers (APNs) associated with the EOR project, nor does it identify the anticipated value of new construction that would occur solely in the EHOF. As construction of the OEHI EOR component would occur over a 20-year implementation schedule, the assessed value of the EOR affected properties would fluctuate from year-to-year. As a result, staff was unable to estimate the property tax impacts associated with the OEHI EOR project.

In addition to the property tax and ad valorem tax on oil and gas holdings, construction spending on materials, equipment, and fixtures would result in payment of sales and use tax that would accrue to the community designated as the "point of sale" or "point of first use" for each transaction.

POINT OF SALE AND USE TAX

In its March 6, 2013 letter to the Energy Commission, Kern County identifies potential impacts to Kern County property owners, residents, and county services if HECA is built. To address such impacts, the Kern County Board of Supervisors requests a mitigation measure be imposed requiring HECA to identify its place of origin as an address within an unincorporated area of Kern County and register that address with the State Board of Equalization, such that the purchase of project equipment and other materials that generate sales tax would benefit Kern County residents. Kern County has proposed the following language for use as a condition of certification for the HECA project. The county stated that this mitigation has been implemented in over 15 other projects with no objection from applicants, including international and out-of-state companies.

> *Prior to the issuance of building permits for the HECA project, the Project Proponent/Operator shall comply with the following: The Project Proponent shall work with the appropriate Kern County Staff to determine how the receipt of sales and use taxes related to the construction of the project will be maximized. This process shall include, but is not necessarily limited to: the Project Proponent/Operator obtaining a street address within the unincorporated portion of Kern County for acquisition, purchasing and billing purposes, registering this address with the State Board of Equalization, using this address for acquisition, purchasing and billing purposes associated with the proposed project. The Project Proponent/Operator shall allow the County to use this sales tax information publicly for reporting purposes.*

In response to Kern County's comment letter, staff is proposing Condition of Certification **Socio-1**. This condition is drafted based on the mitigation measure the county proposed and includes specifics to clarify how the mitigation measure can be more customized to the HECA power plant and OEHI EOR operation facility. This condition would require a good faith effort to ensure the receipt of sales and use tax revenue in the unincorporated area of the Kern County. Terms that would ensure the receipt of sales and use tax could include, but are not be limited to, registration of the two main construction sites, or project office in Buttonwillow, with the California Board of Equalization as the official point of sale, or first use, for tax purposes.

DEPARTMENT OF ENERGY (DOE) FINDINGS REGARDING DIRECT AND INDIRECT IMPACTS OF THE NO-ACTION ALTERNATIVE

Under the No-Action Alternative, DOE would not provide financial assistance to the applicant for the HECA Project. The applicant could still elect to construct and operate its project in the absence of financial assistance from DOE, but DOE believes this is unlikely. For the purposes of analysis in the PSA/DEIS, DOE assumes the project would not be constructed under the No-Action Alternative. Accordingly, the No-Action Alternative would have no impacts associated with socioeconomics.

PROPOSED CONDITIONS OF CERTIFICATION

SOCIO-1 The project owner shall use best efforts to ensure as much sales and use tax revenue resulting from project construction and operation is attributed to Kern County. The project owner shall do the following:

1. Make a good-faith effort to have all transactions that will generate sales and use taxes, including transactions of project owner's contractors, occur in the unincorporated area of the county;
2. Encourage the contractors to establish a business location and tax resale account, and take other reasonable steps, to maximize receipt of sales and use tax revenues for the county;
3. Include in a master contract and any other contract for construction, language ensuring that the county will receive the benefit of any sales and use tax generated by the project to the fullest extent permitted by law;
4. Include the following provision from California Board of Equalization, Regulation 1806(b), in all construction contracts:

   The jobsite is regarded as a place of business of a construction contractor or subcontractor and is the place of sale of "fixtures" furnished and installed by contractors or subcontractors. The place of use of "materials" is the jobsite. Accordingly, if the jobsite is in a county having a state administrated local tax, the sales tax applies to the sale of the fixtures, and the use tax applies to the use of the materials unless purchased in a county having a state-administrated local tax and not purchased under a resale certificate.
5. In all agreements related to the project, identify the jobsite as the project address, which is located within the unincorporated area of Kern County
6. If the project owner enters into a joint venture or other relationship with a contractor, supplier, or designer, the project owner shall either

establish a buying company within Kern County under the terms and conditions of Board of Equalization Regulation 1699(h), to take possession of any goods on which sales and use taxes are applicable but are not defined by Regulation 1806 and shall include in it their requests for bids, procurement contracts, bid documents, and any other agreement whereby California Sales and Use Taxes may be incurred, that the sale occurs at that place of business in the unincorporated area of Kern County; or, alternatively, any entity that may sell goods on which sales taxes are applicable may establish its own place of business within the unincorporated area of Kern County where delivery is ultimately made to the project owner; principle negotiations for all such sales shall be carried on in Kern County;

7. Provide notice to all out-of-state suppliers of goods and equipment, no matter where originating, that Kern County is the jurisdiction where the first functional use of the property is made.

Verification: At least 30 days prior to the start of any project-related pre-construction site mobilization, the project owner shall provide to the CPM (for review and approval, and to Kern County for review and comment), a signed and notarized statement from someone authorized to sign on behalf of the company, with language acceptable to the company and the CPM specifying the terms related to sales and use taxes

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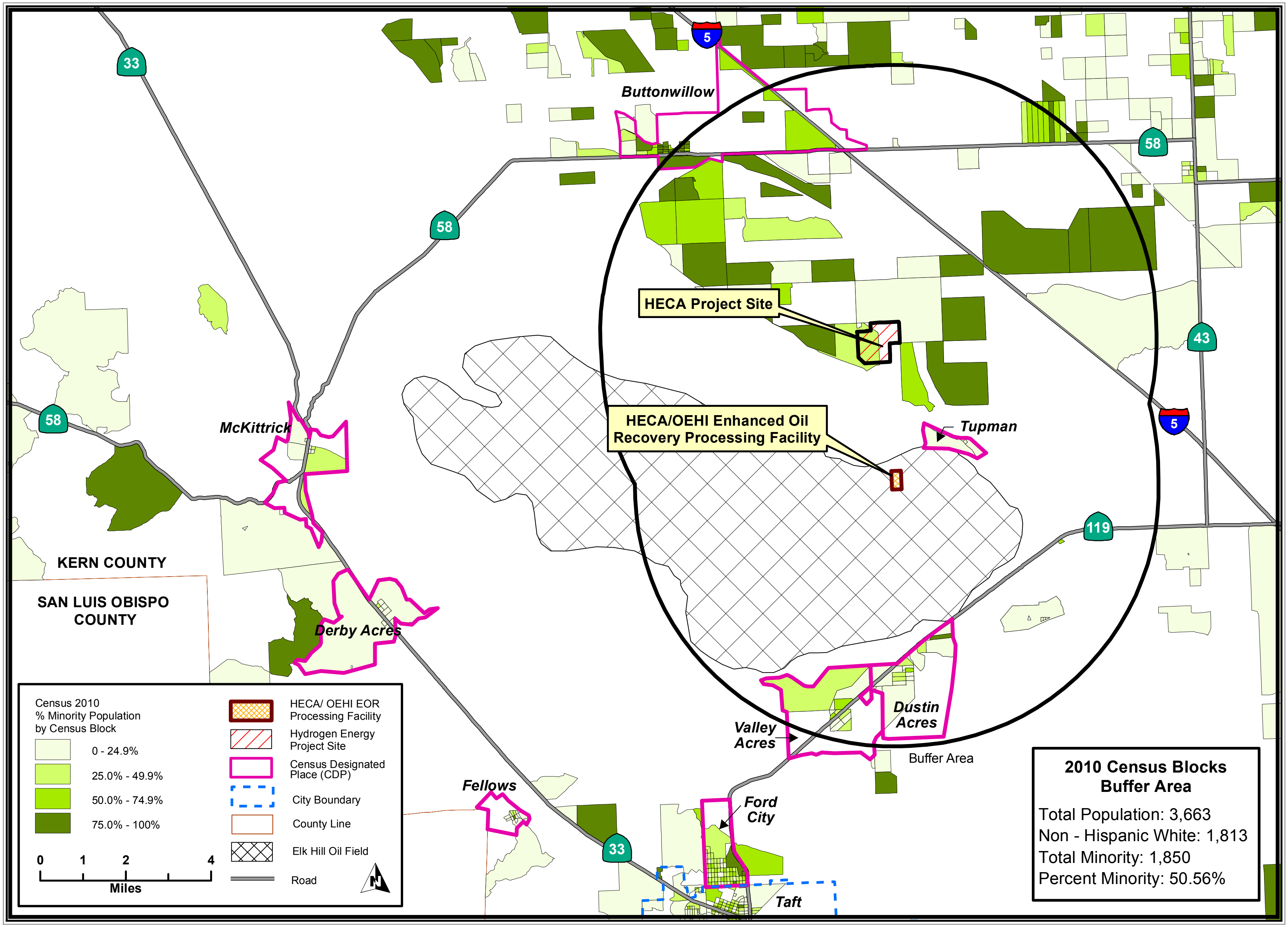
SOCIOECONOMICS - FIGURE 1
Hydrogen Energy California - Census 2010 Minority Population by Census Block



CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING DIVISION
SOURCE: California Energy Commission, URS - Census 2010 PL 94-171 Data

SOIL AND SURFACE WATER

Marylou Taylor, PE

SUMMARY OF CONCLUSIONS

Hydrogen Energy California LLC (the applicant) proposes to construct an Integrated Gasification Combined-Cycle polygeneration project, referred to as the Hydrogen Energy California (HECA) project. This assessment analyzes the potential impacts on soil and surface water resources by HECA and Occidental of Elk Hills, Inc (OEHI) carbon dioxide, enhanced oil recovery (CO_2-EOR) component. Refer to the **Water Supply** section of this Preliminary Staff Assessment/ Draft Environmental Impact Statement for a detailed analysis of the potential impacts on groundwater supplies and groundwater quality.

California Energy Commission (Energy Commission) staff evaluated the potential impacts to: accelerated wind or water erosion and sedimentation; flood conditions in the vicinity of the project; surface water supplies; surface water quality; and compliance with all applicable laws, ordinances, regulations, standards (LORS) and state policies. The affect of these impacts to environmental justice populations are included in this analysis. Staff concludes that construction and operation of the HECA and OEHI CO_2-EOR component would not result in any significant adverse impacts to soil and surface water resources, and would comply with applicable LORS and state policies, provided that the measures proposed in the Application for Certification (AFC) and staff's proposed conditions of certification are implemented.

The HECA site is located outside the designated 100-year floodplain and would not impede or redirect these flood flows. Compliance with staff proposed Conditions of Certification **SOILS-1** through **-6** would reduce or avoid impacts to less than significant of soil erosion, contact runoff, and discharge wastewater during construction and operations. In addition, staff has not identified any significant impacts that would occur as a result of the proposed OEHI CO_2-EOR component. Staff has also concluded that there will be no direct or disproportionate impact to an environmental justice population as identified for the HECA project (see page 51 of this section).

INTRODUCTION

This section of the Preliminary Staff Assessment/Draft Environmental Impact Statement (**PSA/DEIS**) analyzes potential impacts to soil and water resources from the construction and operation of HECA and OEHI CO_2-EOR component. Where the potential of a significant impact is identified, staff proposes mitigation to reduce the significance of the impact and, as appropriate, recommended conditions of certification.

As discussed in the **Introduction** section of this **PSA/DEIS**, this document analyzes the project's impacts pursuant to both the National Environmental Policy Act (NEPA) and CEQA. The two statutes are similar in their requirements concerning analysis of a project's impacts. Therefore, unless otherwise noted, staff's use of, and reference to, CEQA criteria and guidelines also encompasses and satisfies NEPA requirements for this environmental document.

For purposes of the Department of Energy (DOE), this section complies with Executive Order 11988, “Floodplain Management,” which requires federal agencies, while planning their actions, to avoid to the extent possible adverse impacts associated with the modification of floodplains and to avoid support for development in a floodplain when there is a better practicable alternative. This section describes floodplains potentially affected by the construction and operation of the proposed project, and analyzes the potential direct and indirect effects of the proposed project on these resources. This section provides the required floodplain assessment and this PSA/DEIS provides an opportunity for public review in compliance with regulations promulgated at “Compliance with Floodplain and Wetland Environmental Review Requirements” (10 Code of Federal Regulations, Part 1022).

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The following federal, state, and local environmental LORS were established for HECA and similar facilities to ensure the best and appropriate use and management of both soil and water resources. Additionally, the requirements of these LORS are specifically intended to protect human health and the environment. The potential for project compliance with these LORS is a major component of staff’s determination regarding the significance and acceptability of HECA with respect to the use and management of soil and water resources.

Soil & Surface Water Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Federal LORS	
Clean Water Act (33 U.S.C. Section 1257 et seq.)	The Clean Water Act (CWA) (33 USC § 1257 et seq.) requires states to set standards to protect water quality, which includes regulation of storm water and wastewater discharges during construction and operation of a facility. California established its regulations to comply with the CWA under the Porter-Cologne Water Quality Control Act. The CWA also establishes protection of wetlands through section 401 and protection of navigable waters of the U.S. from discharges of dredge and fill material through section 404. Navigable waters can include perennial and ephemeral drainages, streams, washes, ponds, pools, and wetlands. If a discharge would impact navigable waters, then the impacts need to be quantified and mitigated. Section 401 is administered by the states, and in California, through the State Water Resources Control Board/Regional Water Quality Control Boards (SWRCB/RWQCBs). The RWQCB maintains the quality of the State’s water by protecting the function and value of its use. Section 404 is administered and enforced by the U.S. EPA and Army Corps of Engineers (ACOE). Individual permit decisions and jurisdiction determinations are made by the ACOE.

State LORS	
The Porter-Cologne Water Quality Control Act of 1967, California Water Code Section 13000 et seq.	Requires the State Water Resources Control Board (SWRCB) and the nine Regional Water Quality Control Boards (RWQCBs) to adopt water quality criteria to protect state waters. Those regulations require that the RWQCBs issue waste discharge requirements (WDRs) specifying conditions for protection of water quality as applicable. Section 13000 also requires the state to be prepared to exercise its full power and jurisdiction to protect the quality of the waters of the state from degradation. Although Water Code 13000 et seq. is applicable in its entirety, the following specific sections are included as examples of applicable sections.
California Water Code Section 13240, 13241, 13242, 13243, & Water Quality Control Plan for the Sacramento and San Joaquin River Basin (Basin Plan)	The Basin Plan establishes water quality objectives that protect the beneficial uses of surface water and groundwater in the region. The Basin Plan describes implementation measures and other controls designed to ensure compliance with statewide plans and policies and provides comprehensive water quality planning.
California Water Code Section 13260	This section requires filing, with the appropriate RWQCB, a report of waste discharge that could affect the water quality of the state unless the requirement is waived pursuant to Water Code section 13269.
California Code of Regulations (CCR), Title 20, Division 2, Chapter 3, Article 1	The regulations under Quarterly Fuel and Energy Reports (QFER) require power plant owners to periodically submit specific data to the California Energy Commission, including water supply and water discharge information.
Title 23, CCR, Division 3 — SWRCB and RWQCBs	These regulations implement provisions of the CWC and the Porter-Cologne Water Quality Control Act. Among other things, the regulations address water rights, implementation of the federal Clean Water Act, discharges to land, underground tanks, and waste discharge requirements/NPDES permits.
SWRCB Order 2009-0009-DWQ	The SWRCB regulates storm water discharges associated with construction affecting areas greater than or equal to 1 acre to protect state waters. Under Order 2009-0009-DWQ, the SWRCB has issued a National Pollutant Discharge Elimination System (NPDES) General Permit for storm water discharges associated with construction activity. Projects can qualify under this permit if specific criteria are met and an acceptable Storm Water Pollution Prevention Plan (SWPPP) is prepared and implemented after notifying the SWRCB with a Notice of Intent (NOI).
SWRCB Order 2003-0003-DWQ	The SWRCB regulates storm water discharges to land that has a low threat to water quality. Categories of low threat discharges include piping hydrostatic test water.
SWRCB Order 97-03-DWQ	The SWRCB regulates storm water discharges associated with several types of facilities, including steam electric generating facilities. Under Order 97-03-DWQ, the SWRCB has issued a NPDES General Permit for storm water discharges associated with industrial activity. Projects can qualify under this permit if specific criteria are met and an acceptable SWPPP is prepared and implemented after notifying the SWRCB with a Notice of Intent.

California Water Code Section 12899	Department of Water Resources (DWR) is authorized to issue encroachment permits to allow outside parties to construct works within the State Water Project right of way. The permit program is in place to deter the draining or diverting of water that can result in damage to the State Water Project.
Local LORS	
Kern County General Plan-Land Use Element: Resource Goals, Objectives, and Policies Policy LU 1.9.11	Requires that development plans include controls to minimize erosion and sedimentation through utilization of grading and flood protection ordinances.
Kern County General Plan-Land Use Element: Resource Goals, Objectives, and Policies Policy LU 1.9.20	Areas along rivers and streams will be conserved where feasible to enhance drainage, flood control, recreation, and other beneficial uses.
Kern County General Plan-Land Use Element: Resource Goals, Objectives, and Policies Policy LU 1.10.6.34	Ensures that adequate water storage, treatment, and transmission facilities are constructed.
Kern County General Plan-Land Use Element: Resource Goals, Objectives, and Policies Policy LU 1.4.6	Provides a healthful and sanitary means of collecting, treating, and disposing of sewage and refuse.
Kern County Zoning Ordinance 17.28	Regulations that control excavation, grading and earthwork construction, including fills and embankments; establishes the administrative procedure for issuance of permits; and provides for approval of plans and inspection of grading construction.
Kern County Zoning Ordinance 17.48	Prohibits land uses which are dangerous to health, safety, and property loss due to water or erosion hazards, or which result in damaging increases in erosion or in flood heights or velocities.
State Policies and Guidance	
State Water Resources Control Board Resolution No. 68-16	The “Antidegradation Policy” mandates that: 1) existing high quality waters of the State are maintained until it is demonstrated that any change in quality will be consistent with maximum benefit to the people of the State, will not unreasonably affect present and anticipated beneficial uses, and will not result in waste quality less than adopted policies; and 2) requires that any activity which produces or may produce a waste or increased volume or concentration of waste and which discharges or proposes to discharge to existing high quality waters, must meet WDRs which will result in the best practicable treatment or control of the discharge necessary to assure that: a) a pollution or nuisance will not occur and b) the highest water quality consistent with maximum benefit to the people of the State will be maintained.

PROPOSED PROJECT

SETTING AND EXISTING CONDITIONS

The proposed Hydrogen Energy California (HECA) project would be constructed on a 453-acre site located in western Kern County, seven miles west of Bakersfield and a mile and half northwest of the unincorporated community of Tupman. The applicant has an agreement to purchase the proposed project site from the current land owner, as well as an additional 653 acres adjacent to the site, referred to as the Controlled Area (see **Soil & Surface Water Figure 3**), which the applicant would control access and future land uses (HECA 2012e, §2.1.6). The HECA site is approximately 286 feet above mean sea level (amsl) (HECA 2012bb, §A116). The proposed Occidental of Elk Hills, Inc (OEHI) carbon dioxide, enhanced oil recovery (CO_2-EOR) component would be constructed within the Elk Hills Oil Field on approximately 102 acres located about 3.4 miles south of the HECA site. The Elk Hills Oil Field is approximately 74 square miles and characterized as mountainous terrain with slopes averaging 30 percent or greater. The topography slopes from southwest to northeast towards the California Aqueduct. The elevation of the project area ranges from 1,500 to 300 feet amsl at the Aqueduct (HECA 2012e, Vol. II).

The Central Valley climate is semi-arid, creating hot dry summers and mild winters. Based on the period 1971 to 2000, the average winter temperature in Buttonwillow (located approximately 4 miles northwest of the HECA site) is 47.8 degrees Fahrenheit (°F) and the average summer temperature is 94.9 °F. Precipitation in the area is characterized by long, dry summers and intermittent wet periods. Over the same time period, the average annual precipitation at Buttonwillow was 6.41 inches[1].

Agriculture is the primary land use at the HECA site and local vicinity, with onions, cotton, and alfalfa currently being cultivated on the proposed project site (HECA 2012bb, §A116). Because the climate is semi-arid, almost all crops in the western portion of Kern County must be irrigated. The Elk Hills Oil Field has been producing oil and gas for 100 years[2]. The CO_2-EOR component would be located on a portion of the oil field where primary and secondary phases of oil recovery were employed to retrieve oil and/or gas from the field's underground reservoir[3]. The CO_2-EOR component is a tertiary phase method that would retrieve additional product that previous phases were not able to recover.

As discussed in the **Socioeconomic Resources** section of this **PSA/DEIS**, the minority population in the six-mile buffer around the HECA site and CO_2-EOR component constitutes an environmental justice population as defined by *Environmental Justice: Guidance Under the National Environmental Policy Act*. As a result, this analysis must identify whether the construction and operation of the proposed HECA project, including the associated EOR operation, could therefore have significant, unmitigated impacts or disproportionate impacts on an environmental justice population.

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[1] Climate Narrative for Kern County, California (www.wcc.nrcs.usda.gov/cgibin/soil-nar-state.pl?state=ca)

[2] The oil field was originally developed as part of the federal Naval Petroleum Reserves with the U.S. Navy being the original operator. In 1998, the oil field was acquired by OEHI.

[3] During primary recovery, the natural pressure of the reservoir or gravity drive oil into the wellbore, combined with artificial lift techniques (such as pumps) which bring the oil to the surface. But only about ten percent of a reservoir's original oil in place is typically produced. Secondary recovery techniques extend a field's productive life generally by injecting water or gas to displace oil and drive it to a production wellbore, resulting in the recovery of 20 to 40 percent of the original oil in place (http://fossil.energy.gov/programs/oilgas/eor/).

Regional Setting

HECA would be built on the southwestern side of the San Joaquin Valley, contained between the Coast Ranges to the west, the Emigdio and Tehachapi Mountains to the south, and the Sierra Nevada to the east. California's Central Valley is filled with up to 32,000 feet of sedimentary rock eroded from the adjacent mountain ranges. The proposed site is approximately three miles north of the Elk Hills oil field, the proposed location of carbon dioxide injection. The Elk Hills form the surface expression of an anticline composed of gravel and mudstone (HECA 2012e, §2.1).

Watershed

The primary responsibility for the protection of water quality in California rests with the State Water Resources Control Board (SWRCB) and nine Regional Water Quality Control Boards. This portion of Kern County falls under the jurisdiction of the Central Valley Regional Water Quality Control Board (CVRWQCB). The Water Quality Control Plan for the Tulare Lake Basin (Basin Plan) designates beneficial uses for water bodies within the region, and establishes water quality objectives and implementation plans to protect beneficial uses. The identified beneficial uses define the resources, services, and qualities of these aquatic systems that are the ultimate goals of protecting and achieving high water quality.

The Central Valley Region is divided into three basins: the Sacramento River Basin, the San Joaquin River Basin, and the Tulare Lake Basin. The proposed HECA site and CO_2-EOR site are located in the Tulare Lake Basin, which is essentially a closed basin situated at the south end of the Central Valley. The region is the driest of the Central Valley, but once contained the largest single block of permanent and seasonal wetlands in California. Today, these areas are heavily farmed, with all the region's streams diverted for irrigation or other purposes, except in the wettest years (DWR 2009). As irrigation infrastructure was built, the historical Tulare Lake was gradually cut off from its sources of inflow. The Tulare Lakebed was first reported to be dry in 1899 (ECORP 2007).

Historically, the streams drained runoff from the surrounding mountain range into natural depressions on the valley floor, Kern (dry) Lake, Buena Vista (dry) Lake and Tulare (dry) Lake, which receive flood water from the major rivers during times of heavy runoff (see **Soil & Surface Water Figure 1**). Historic floods through the HECA site typically resulted from excess flows that exceeded the banks of the Kern River. During extremely heavy runoff, flood flows north in the Kings River to reach the San Joaquin River (see **Soil & Surface Water Figure 2**). These occasional northbound flood flows represent the only significant outflows from the basin. Normally all native surface water supplies, imported water supplies, and direct precipitation percolate into valley ground water if not lost through consumptive use, evaporation, or evapotranspiration[4] (RWQCB 2004).

[4] Evapotranspiration is the return of water vapor to the atmosphere by evaporation from land and by transpiration from plants.

The Elk Hills Oil Field has relatively limited surface water resources, with a terrain of numerous, rounded divides and smooth slopes. The drainage divide follows the crest of Elk Hills, causing runoff to flow generally to the north and south. A large number of ephemeral/intermittent streams draining the hills have created a highly dissected stream pattern of gullies and channels. The primary drainage channels do not merge into an integrated network. The natural course of some of the channels in the northern flank is interrupted by the California Aqueduct, and many terminate naturally due to infiltration, and others terminate in gully plugs. Drainage channels in the central portion of the southern flank join Buena Vista Creek in Buena Vista Valley. Watersheds draining the western part of Elk Hills convey runoff in the direction of McKittrick Valley, which slopes towards the northwest (OXY 2012b).

Canals

HECA would be built within 0.5 miles of the California Aqueduct and the proposed groundwater supply would be pumped within approximately 2 miles of the aqueduct (HECA 2012e, §5.14.1). The California Aqueduct is a significant conveyance component of the State Water Project (SWP) managed by the California Department of Water Resources (DWR), which begins at the Sacramento-San Joaquin River Delta and continues south through the Central Valley, over the Tehachapi Mountains, and into southern California. The State Water Project provides a water supply for up to 25 million Californians and up to 750,000 acres of irrigated agriculture and is a vital water supply for many southern Californians. The aqueduct is 444 miles long and is mostly an open concrete-lined canal. The canal width and depth vary along the length of the aqueduct, but it is generally approximately 50 feet wide and approximately 30 feet deep[5].

Long-held water rights determine the amount of water that can be delivered to any particular user in any particular year based on projected volume of runoff. Water districts in the western area of the valley floor depend heavily on contracts for imported water from the State Water Project (SWP) via the California Aqueduct and the Central Valley Project (CVP) via the Friant-Kern Canal. These two projects follow a coordinated operation agreement for water shortages, water quality, and environmental requirements (DWR 2009). Another source of irrigation water is the Kern River, which is fed by the annual snowmelt from the Southern Sierra Nevada Mountains and stretches to the City of Bakersfield. Except during very wet years, there is no river flow downstream of Bakersfield due to upstream canal diversions (KJC 2011).

Several regional irrigation and water supply canals are located in the vicinity of the HECA site. The Outlet Canal and West Side Canal are located approximately 0.1 mile and 0.2 mile south of the site, respectively. The East Side Canal is located approximately 0.3 mile east of the project site boundary. Closer to the site, an irrigation canal extends generally from the east to the west from Tupman Road along the site's southern border. This irrigation canal connects the East Side Canal with the West Side and Outlet Canal (HECA 2012bb, §A116).

[5] www.water.ca.gov/swp/

Currently existing on the proposed HECA site, an irrigation ditch crosses approximately three-quarters of the site from south to north, runs diagonally northwest through the former natural fertilizer manufacturing plant area, and ends just south of Adohr Road. This ditch is approximately 7 feet deep and feeds the smaller irrigation ditches that traverse the site from north to south and east to west around the crop fields. These irrigation ditches are fed with water pumped from the canal south of the site, which is supplied by the West Side Canal and the East Side Canal (HECA 2012bb, §A116).

Flood Management

To lessen the flood risk to life and property, a combination of Federal, State, and local agencies have responsibilities in the overall effort to manage floods. The Federal Emergency Management Agency (FEMA) prepares 100-year flood maps for flood insurance purposes and for floodplain management use by local agencies to reduce the impact of flooding. FEMA map 06029C2225E indicates that the entire Elk Hills Oil Field is designated Zone X[6]. The U.S. Army Corp of Engineers (USACOE) was contracted to perform a floodplain study of the Elk Hills Oil Field which was completed in 1993. The results show that the 100-year floodplain boundaries are confined to isolated areas immediately adjacent to a few drainage channels. In every instance the floodplain widths are approximately 100 feet wide, with only four exceptions where flows fan out at the very northern and southern stretches to widths ranging from 440 to 1600 feet (OXY 2012b).

FEMA maps 06029C-2225E and 06029C-2220E cover the proposed HECA site and the surrounding area. The entire HECA site is designated Zone X, which has very little risk of encountering flood flows. The nearest area subject to 100-year floodplain Zone A[7] is along the Kern River Flood Control Channel located approximately 500 feet southwest of the project site (see **Soil & Surface Water Figure 3**). The levees of this flood control channel, which were constructed to protect the surrounding areas from the 100-year flood, prevent these flood flows from inundating the proposed HECA site.

In 1953, the USACOE built earthen dams across the north and south forks of the Kern River to create the Isabella Reservoir. Isabella Dam (referring to both the Main Dam and Auxiliary Dam) is located approximately 42 miles northeast of Bakersfield. It was designed to help reduce flood risk for Bakersfield and the surrounding region, and is a primary water source for water users throughout Kern County (ACOE 2012). The Kern River continues downstream of Isabella Dam and flows southwest toward Bakersfield (see **Soil & Surface Water Figure 2**) at the valley floor where various diversions and weirs distribute water through a total of seven canals that pass through the City of Bakersfield. Except during very wet years, the river is dry or near dry downstream of

[6] Zone X is defined by FEMA as an area determined to be outside the 0.2% annual chance flood also known as the 500-year flood (the flood that has a 0.2% chance of being equaled or exceeded in any given year). See www.fema.gov.

[7] Zone A is defined by FEMA as special flood hazard area subject to inundation by the 1% annual chance flood also known as the 100-year flood (the flood that has a 1% chance of being equaled or exceeded in any given year). Because detailed analyses are not performed for Zone A, no depths or base flood elevations are shown within these zones. See www.fema.gov.

Bakersfield due to upstream canal diversions[8]. When flows in the Kern River exceed the capacity of these diversion canals, water continues southwest past Bakersfield to the Buena Vista (dry) Lakebed, located approximately eight miles southwest of the HECA site near Tupman (KJC 2011).

The Buena Vista Aquatic Recreational Area occupies a portion of the Buena Vista (dry) Lakebed, a natural depression on the valley floor. Two separate aquatic lakes, Lake Evans and Lake Webb, provide the primary attraction for boating, skiing, sailing, and fishing (KJC 2011). The historic Buena Vista (dry) Lakebed is heavily farmed, but up to 30,000 acre-feet of Kern River floodwater can be stored in this area, per agreements between the landowners and Buena Vista Water Storage District (ECORP 2007).

In addition to inundating the Buena Vista (dry) Lakebed, excess flows could be directed north to the Tulare (dry) Lake via the Kern River Flood Control Channel or directed to the California Aqueduct via the Kern River-California Aqueduct Intertie (Intertie) located near Tupman (see **Soil & Surface Water Figure 4**). The Intertie is a structure built by the USACOE in 1977 to convey Kern River flood water into the aqueduct. Its purpose is to avoid damage to lands downstream, especially the farmland in the Tulare Lake Basin. In years when potentially damaging flow to the Tulare Lake Basin may occur, all or a portion of the excess flow is diverted to the California Aqueduct via the Intertie[9] (ECORP 2007). The Kern River Flood Control Channel is under the jurisdiction of Central Valley Flood Protection Board and the Intertie is under the jurisdiction of Kern County Water Agency.

Groundwater Resources

For a detailed discussion of the regional groundwater resources, refer to the **Water Supply** section of this **PSA/DEIS**.

PROPOSED PROJECT DESCRIPTION

The applicant proposes to construct an Integrated Gasification Combined-Cycle polygeneration project, referred to as the Hydrogen Energy California (HECA) project. HECA would use a blend of petroleum coke and coal to produce synthesis gas (syngas), which would be purified to hydrogen-rich fuel used to generate electricity. This combined cycle plant would produce from 405 to 431 gross-megawatts (MW) and provide up to 300 MW of power to the grid. The HECA site would include an integrated manufacturing complex to produce approximately 1 million tons per year of low-carbon nitrogen-based products, including urea, and urea ammonium nitrate (UAN), to be used in agricultural applications (HECA 2012e, §2.1).

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[8] Not all flows are diverted for agricultural uses. An agreement was signed in 1999 allowing some flows to remain in the Kern River during summer months in most years for recreation purposes at the Kern River Parkway area, located in the City of Bakersfield, and for groundwater recharge (ECORP 2007).

[9] From1977 through 2006, excess flows were directed to the Aqueduct during 10 of these years. The largest volume occurred in 1983 with 750 thousand acre-feet of floodwater. In 1969, prior to construction of the Intertie, it is estimated about 227 thousand acre-feet of Kern River flow reached the Tulare Lakebed (ECORP 2007).

Other major items of HECA would include (HECA 2012e, §2.1):

- Supporting process systems – raw water treatment, wastewater treatment, air separation unit, and other plant systems; and
- Linear facilities – an electrical transmission line, a natural gas supply line, water supply pipelines (both process water and potable water), a carbon dioxide pipeline, and potentially an Industrial Railroad Spur.

Additionally, the gasification block would capture 90 percent of raw syngas carbon dioxide (3 million tons per year). Approximately 2.6 million tons per year would be transported via a 12" diameter pipeline to the Elk Hills Oil Field, approximately 3.4 miles to the south, where it would be used to facilitate carbon dioxide, enhanced oil recovery (CO_2-EOR) and resulting sequestration (storage) of the CO_2 (HECA 2012e, §2.1).

In CO_2-EOR operations, compressed CO_2 (which has the characteristics of a liquid) is injected into an oil reservoir through injection wells designed for CO_2 injection. The CO_2 flows from the injection well and dissolves in the oil. To optimize CO_2-EOR performance, a technique of alternating cycles of water injection with cycles of CO_2 injection may be used (referred to as "Water Alternating Gas" or "WAG"). The fluids produced by this process would be a mixture of hydrocarbons (oil and gas), water and CO_2, which would be processed on-site. At the surface, the recovered fluids would be transferred to a separator at the EOR Processing Facility where the oil, water, and natural gas would be separated. Separated natural gas would enter a pipeline for transport to the existing gas processing facility to combine and process with other produced gas from the field for sale to customers. The CO_2 separated from the produced natural gas would be recompressed for reinjection along with more CO_2 purchased from HECA to further optimize the CO_2-EOR process (HECA 2012e, Vol. II).

Major elements of the CO_2-EOR component are (OXY 2012f, Attach A177-2):

- CO_2 Injection and Recovery Equipment – CO_2 supply system, 13 satellite gathering stations, infield gathering and injection distribution pipelines
- Recovered CO_2 Purification and Compression – central tank battery (CTB), reinjection compression facility (RCF), CO_2 recovery plant (CRP), water treating and injection plant
- Backup CO_2 Injection Facility
- Supporting Process Systems – hazardous material management, hazardous waste management, storm water management, fire protection, control systems, utilities, project buildings/facilities, security systems
- CO_2 sequestration, monitoring, measurement, verification and closure

Although the CO_2-EOR component of the project would occur at the Elk Hills Oil Field, which is outside Energy Commission jurisdiction[10], these proposed activities are

[10] For further discussion on jurisdictional authority over the CO_2-EOR component of the project that would occur at the Elk Hills Oil Field, refer to the **Project Description** section of this **PSA/DEIS**.

considered in the **PSA/DEIS** as part of the whole of the HECA project. Therefore, CEQA assessment of impacts to soil and water resources of both HECA and CO_2-EOR component are included in this section.

Refer to the **Project Description** section of this **PSA/DEIS** for more information on HECA major features including water use, wastewater handling, and storm water handling. Additional information relevant to the soil and water resources analysis is summarized below. For a complete detailed description of the proposed project, refer to the HECA Application for Certification ([AFC] HECA 2012e) and the applicant's related supplemental material.

Construction of the proposed HECA is anticipated take 42 months to complete. The project would have a project lifespan of 25 years, and the applicant requests that commercial operation begin in September 2017 (HECA 2012e, §2.1). Initial construction of the proposed CO_2-EOR component is anticipated take about 32 months to complete and would have a project lifespan of 20 to 40 years (OXY 2012f, Attach A177-2).

Soil Disturbance and Grading

HECA Site and Laydown Areas

The existing project site topography is generally flat, but some grading would be required to provide a level area for project construction. Earthwork associated with HECA would include site grading for drainage as well as excavation for foundations and underground systems. Excavated material suitable for compaction would be stockpiled in designated onsite locations. Soil unsuitable for supporting facility foundations or pavement would be excavated and used to level open areas and to construct the earthen berms located at the north and east fence lines (HECA 2012e, §2.7.1).

Preliminary grading plans indicate approximately 850,000 cubic yards of excavated soil and 500,000 cubic yards of imported fill. Syndex Ready Mix, a commercial aggregate company located within five miles of the site in Buttonwillow, is expected to provide the imported fill material (HECA 2012r, §26). No onsite or offsite fill disposal is expected (HECA 2012e, §5.9.2.1).

Gravel and road base material would be used to help stabilize soil for temporary construction roads, laydown, parking, and work areas (HECA 2012e, §2.7). Other erosion control measures would include (HECA 2012bb, §A116):

- tracking weather conditions and maintaining soil stabilization of disturbed areas prior to and during rain events.
- arranging the construction schedule as much as practicable to leave existing vegetation undisturbed until immediately prior to grading; and
- placing temporary soil stabilization and sediment control measures as soon as possible after grading, and permanent erosion control as soon as possible after construction is complete.

At the end of construction, temporary disturbance areas would be cleaned up and restored to their pre-construction conditions (HECA 2012bb, §A116).

Linear Facilities

Construction of proposed linear facilities would include installation of approximately 32 miles total of underground pipelines, as well as construction of a transmission line and potentially an industrial railroad spur (see **Soil & Surface Water Figure 5**). Construction of the underground pipelines would consist primarily of crews performing the following typical pipeline construction activities: hauling and stringing of the pipe along the route; welding; radiographic inspection; coating of the pipe welds; trenching; lowering of the pipe into the trench; backfill of the trench; hydrostatic testing of the pipeline; purging the pipeline; and cleanup and restoration of construction areas. Grade cuts would be restored to their original contours and affected areas would be restored to their original state to minimize erosion (HECA 2012bb, §A116).

At areas where pipes would cross certain watercourses and roadways, the applicant proposes to use horizontal directional drilling (HDD) to avoid direct disturbances at these locations. HDD involves drilling from the ground surface adjacent to the area of concern, such as a stream, using a technique that guides the direction of the drill to pass under the stream and emerge on the ground surface on the opposite side without disturbing the streambed. Staging areas are required at the entry and exit points of the drill, with each “entry pit” requiring a temporary disturbance area of approximately 120 feet by 100 feet and each “exit pit” requiring an area of approximately 75 feet by 100 feet (HECA 2012bb, §A116).

Construction and installation of the electrical transmission line would follow a sequence similar to that of underground facilities, with trench excavation being replaced by augering of holes to facilitate placement of the reinforced concrete foundations for the tubular-steel transmission structures, followed by backfilling and compaction. Grade cuts would be restored to their original contours, and affected areas would be restored to their original state to minimize the potential for erosion. To the extent possible, the material excavated from trenches and auger holes would be used to backfill around the foundations and in the trenches. Additional excess material that cannot be reused along the easement corridor would be transported to another reuse area or disposed of at an offsite landfill facility (HECA 2012bb, §A116).

Construction and installation of the industrial railroad spur would follow a typical method used on similar rail projects. Work would consist of clearing and grubbing, rough grading, tract embankment fill, drainage ditches, drainage culverts, road crossings, ballast placement, track placement, and crossing signals/signs. Some existing utility relocation work is anticipated which would be performed during rough grading. BMPs would be implemented to minimize construction-related impacts on soils and agricultural lands (HECA 2012bb, §A116).

CO_2-EOR Component

Currently at the proposed site of the CO_2-EOR component, over 200 water injection wells are used as secondary phase oil recovery to inject produced water[11] from the Elk Hills oil field, “sweep” or displace oil from the reservoir, and push the oil towards a production well. The proposed CO_2-EOR component would convert many of the existing water injector wells to CO_2 injector wells for WAG. CO2 from HECA would be transported via a pipeline to the CO_2-EOR facility, at which point the CO_2 would be distributed to CO_2 injection wells placed in a well pattern designed to optimize the recovery of oil from the reservoir. For each injection well there may be three or more nearby production wells where produced fluids are pumped to the surface and then transported by pipeline in a closed loop system to a centralized collection and processing facility. The recovered fluids would be transferred to a separator at the CO_2-EOR facility where the oil and natural gas are separated. The natural gas would be combined with other produced gas from the field for sale to customers. The CO_2 would be recompressed for reinjection along with additional purchased CO_2 from HECA to further optimize the CO_2-EOR process (HECA 2012e, Vol. II).

Disturbed Areas

Construction of HECA and associated linear facilities would affect the areas listed in **Soil & Surface Water Table 2**. Soil disturbance would occur as a result of grubbing, grading, and/or excavation activities. After construction, some of these areas would be covered with impervious material (i.e. concrete foundations, asphalt pavement) and temporary construction areas would be restored to natural existing conditions.

Soil & Surface Water Table 2
Disturbed Acreage (HECA and Linear Facilities)

Project Component	Temporary Disturbance[1] (acres)	Permanent Disturbance[2] (acres)
HECA Site (453 acres) Construction time: approximately 42 months	453	453
Temporary Construction Laydown Areas (in the Controlled Area) Construction time: approximately 42 months	91	None

[11] Produced water is a term used in the oil industry to describe water that is produced when oil and gas are extracted from the ground.

Project Component	Temporary Disturbance[1] (acres)	Permanent Disturbance[2] (acres)
Electrical transmission line (approx. 2.1 miles) Temporary: 25-foot wide road, plus up to 25-foot-diameter structural base for each of 15 poles. Permanent: Up to 25-foot diameter structural base for each of 15 poles. Construction time: approximately 3 months	7.35	0.15
Natural gas pipeline (approx. 13 miles) Temporary: 50 feet wide, plus 100-foot by 100-foot metering station at the inlet. Disturbance area shared with railroad spur. Permanent: Metering station at the inlet. Construction time: approximately 6 months	47.43[3]	0.23
BVWSD well field and process water pipeline (approx. 15 miles) Temporary: 50 feet wide, plus 150-foot by 100-foot area around each of 5 wells. Permanent: areas around each of 5 wells (100 feet by 100 feet). Construction time: approximately 6 months	90.25	1.15
Potable water pipeline (approx. 1 mile) Temporary: 10 feet wide and within transmission line corridor. Permanent: None. Construction time: approximately 3 months	Included with transmission line[4]	None
Railroad spur (Single track railroad approx. 5.3 miles) Temporary: 75 feet wide, plus 3 acres of laydown area. Permanent: 60 feet wide. Construction time: approximately 5 months	51	38.4

Project Component	Temporary Disturbance[1] (acres)	Permanent Disturbance[2] (acres)
PG&E Switching Station (4 acres) Construction time: “a few months”	4	4
OEHI Carbon dioxide pipeline[5] (approx. 3.4 miles) Temporary: 80 feet wide, plus 2 entry pits (120-foot by 100-foot each) and 2 exit pits (75-foot by 100-foot each) for HDD, plus two 50-foot by 50-foot valve box areas. Permanent: two 50-foot by 50-foot valve box areas. Construction time: approximately 6 months	29	0.11
Total	773	497

Sources: HECA 2013u, §A211; HECA 2012e, §5.14

Notes:

1. Temporary disturbance area is the total area disturbed during construction.
2. Permanent disturbance area is the disturbed/developed area that remains after construction.
3. The temporary disturbance area along the portion of the natural gas linear that follows the railroad spur from the project site to the interconnection of the railroad with the existing San Joaquin Valley Railroad line is included in the temporary disturbance area for the railroad spur.
4. The potable water pipeline temporary disturbance area is included in the temporary disturbance area for the electrical transmission line.
5. Sources: HECA 2012e, App A-2; HECA 2012s, §A59

The location of the proposed CO_2-EOR component is heavily industrial with large areas of significant disturbance. Proposed facilities include: CO_2-EOR Processing Facility, 13 Satellite Stations, new injection and production wells, new water distribution lines, and pipelines for producing and injection lines (see **Soil & Surface Water Figure 6**). A substantial portion of the CO_2-EOR component would utilize these existing disturbed acreages, well sites and pipeline alignments, however additional pipelines, satellites, and well sites would be required (HECA 2012e, Vol. II, OXY 2012f, Attach A177-2).

- Four new buildings for the CO_2-EOR component: administration/control building, maintenance/warehouse building, and two compressor shelters
- The estimated total length of all new pipelines is 652 miles, much of which will be located in existing pipeline corridors that are sited on disturbed acreage. Disturbances would be minimized due to multiple pipelines being bundled when practical and some types of pipelines being installed using pipe-rack support located above ground.
- The current estimated number of producing and injection wells is approximately 720 (309 injection and 411 production wells). Existing wells would be used for 570 of the wells. The remaining 150 wells would be new installations.
- **Soil & Surface Water Table 3** shows the total estimated disturbances from the various project components.

Soil & Surface Water Table 3
Disturbed Acreage (CO_2-EOR Component)

Project Component	Temporary Disturbance (acres)	Permanent Disturbance (acres)
CO_2-EOR Processing Facility and Central Tank Battery	-	101.8
CO_2-EOR Satellite Stations (2.6 acres for each of 13 stations)	-	33.8
New Well Installations (0.84 acres for each of 150 new wells)	-	126
Buried Pipelines (approx. 260.5 miles)	1448	None

Source: HECA 2012e, Vol. II

Different areas within the CO_2-EOR component site would be disturbed at different times during the 20 year construction phase of the proposed project. The CTB, which is the primary oil/water separation system for the CO_2-EOR process, would be designed based on two units operating at a maximum design capacity of 50 percent. One unit would be installed initially. The second unit will be installed when liquid production increases above 50 percent of maximum design capacity for the first unit (OXY 2012f, Attach A177-2).

In the initial years of CO_2-EOR operations, the average CO_2 content in the produced gas is relatively low. As a result, only the RCF equipment would be required to process the lower quantities of CO_2 for approximately the first 4 years of production. When CO_2 injected in the reservoir reaches the production wells in larger quantities, “breakthrough” has occurred. At this point, the CRP will be constructed to recover the larger quantities of CO_2. Both RCF and CRP operate at partial load until peak gas rate is reached approximately 6 years later (OXY 2012f, Attach A177-2).

Three of the proposed 13 Satellite Gathering Stations would be constructed initially, which would be sufficient to accommodate CO_2 volumes provided by HECA. Installation of systems would start in the eastern portion of the CO_2-EOR site, then the other ten systems would be added over time and progress westerly as reservoir development evolves. Approximately 10 to 12 years after startup, injection systems will be installed in the northwest area (OXY 2012f, Attach A177-2).

Storm Water and Drainage

HECA Site and Laydown Areas

The proposed HECA site is within agricultural fields with relatively flat topography and roughly 1-percent grade. During rain events, storm water that does not soak into the ground runs generally from east to west across the project site. Surface water runoff in the area is intersected directly along various paved roads, levees, and irrigation ditches located within and surrounding the site (HECA 2012bb, §A116).

The HECA site would require earthwork movement to form level building pads for the various HECA process areas and associated facilities. All existing irrigation ditches within the project site would be abandoned and filled in to meet design elevations. **Soil & Surface Water Figure 7** shows the project's major components. They would be placed on concrete pads and grouped into different areas as follows:

- the main plant area that includes the power and gasification blocks, acid gas removal (AGR), fertilizer complex, water treatment, and associated cooling towers;
- the ammonia and methanol storage area;
- the air separation unit (ASU) and associated cooling tower;
- the remote solids handling area; and
- the administration complex.

The completed HECA facility would increase the site's impervious area from the current three percent to a total of 29 percent of the entire 453 acres, consequently increasing the amount of storm water runoff during rain events (HECA 2012bb, §A116).

Storm water runoff would be directed to one of the onsite retention basins or sumps designed to prevent onsite storm water from leaving the site. Additionally, the potentially polluted contact[12] storm water would be completely separated from non-contact storm water runoff. Runoff would be managed as follows (HECA 2012bb, §A116):

- Potentially contaminated storm water runoff from the ASU and main plant areas would be collected and routed to retention basins with an impermeable liner. Water would be tested to determine an appropriate destination for reuse. Depending on the water quality, it may be used for cooling tower makeup, used for gasifier slurry water makeup, or disposed in one of the zero liquid discharge (ZLD) systems. (Further description of ZLD is found in the "Wastewater" subheading below.)
- Storm water that may be contaminated with oil would be separately collected then routed to an oil/water separator, and the separated water would be either reused in the facility or processed in a ZLD system.

[12] Contact runoff refers to storm water in contact with exposed polluted or hazardous materials and/or surfaces that can potentially result in contaminated runoff (containing trace oil, chemicals, metals, toxic substances, or other materials).

- Runoff in the AGR unit would be collected in a separate lined retention basin, dedicated for AGR storm water runoff. This isolated basin would also contain any potentially contaminated water that could result in the event of a methanol spill.
- Storm water runoff from chemical and oil storage areas would be held within the associated secondary containment. The captured water would be tested later then, based on the results, routed to an oil/water separator or to a retention basin.
- Storm water within the process plant area where solids are present (e.g., coal, petcoke, or gasification solids) would be collected and conveyed to the solids handling water collection facility. The collection facility would be constructed of concrete and would provide for mobile equipment access to remove accumulated solids. Water that accumulates within the collection facility would be processed in the ZLD system at the wastewater treatment plant.
- Storm water from remote solids handling areas, such as the feedstock unloading and the crusher station, would be collected in solids drain sumps for settlement, testing, reuse, and/or treatment as appropriate.
- Non-contact storm water runoff from administration complex and areas outside the main plant areas would be routed to storm water retention basins to allow sediment to settle. The water would be filtered and reused as cooling tower makeup water. If this collected storm water is determined unsuitable for cooling tower use, then it would be reused in the slurry preparation area or disposed of in one of the ZLD systems.
- Existing drainage patterns of storm water outside the site boundary would remain undisturbed. Offsite runoff would follow existing drainage patterns to convey flow around the project site. No runoff from outside the site boundary would flow onto the site.

Prior to construction, the applicant would prepare a Storm Water Pollution Prevention Plan (SWPPP) to control storm water and soil erosion during the facility's construction using best management practices (BMPs)[13]. Similarly for the facility's operation, a Storm Water Management Plan with a corresponding SWPPP would be developed to manage storm water and prevent soil erosion through the life of the project (HECA 2012bb, §A116).

Linear Facilities

During construction of linear facilities, measures to avoid or reduce storm water impacts include (HECA 2012bb, §A116):

- Avoiding sensitive habitats by developing construction exclusion zones and silt fencing in sensitive areas;

[13] Storm water and soil erosion BMPs are methods that have been determined to be the most effective, practical means of preventing or reducing pollution from nonpoint sources. BMPs can be classified as "structural" (i.e., devices installed or constructed on a site) or "non-structural" (procedures, such as modified landscaping practices). There are a variety of BMPs available, depending on pollutant removal capabilities.

- Avoiding wetlands and water courses where possible by establishing a distance of at least 10 feet between construction activities and these areas; and
- Preventing flows from work areas into surrounding water systems by installing physical barriers and other BMPs during construction.

At the end of construction, temporary disturbance areas would be cleaned up and restored to their pre-construction conditions (HECA 2012bb, §A116).

CO_2-EOR Component

During construction activities, clean storm water runoff from the site would be routed to an onsite storm water retention basin. A project-specific construction storm water pollution prevention plan (SWPPP) would be developed prior to construction. Storm water runoff at the CO_2-EOR component would be managed using BMPs, Rainfall Erosivity Waiver, or Notice of Intent (NOI) coverage under California Stormwater Construction General Permit, as appropriate. Construction project site storm water runoff in non-process areas but within the main plant area would be routed to a retention basin. Retention basins and storm water collection/conveyance systems would be designed in accordance with the Kern County Development Standards (OXY 2012f, Attach A177-2).

Initial plant construction would include the RCF, one unit of the CTB, supporting buildings/structures, and three Satellite Stations (with corresponding wells and piping).

After initial plant construction is complete, construction activities would continue to expand the CO_2-EOR processing facility and oil field with additional Satellite Stations.

All construction activities would continue to be subject to the project-specific construction SWPPP. Storm water from non-process areas outside the main plant area but within the CO_2-EOR component site is expected to reflect natural drainage conditions. Runoff from these areas follows natural drainage patterns of the Elk Hills Oil Field (OXY 2012f, Attach A177-2).

Project Water Use

For a detailed water use discussion of HECA and the CO_2-EOR component, refer to the **Water Supply** section of this **PSA/DEIS**.

Wastewater Management

HECA: Industrial

The primary sources of the project's wastewater would be from cooling tower blowdown, raw water treatment, process condensate wastewater from the gasifier, the sour water stripper, the AGR unit, and the Urea Plant. Process wastewater would be treated on-site and recycled to the cooling towers as make-up water. Cooling tower blowdown would also be treated on-site to produce demineralized and utility water. The reject from the cooling tower blowdown treatment plant would be sent to a zero liquid discharge (ZLD) system. The ZLD unit produces both high purity water that gets treated and recovered for further use within the plant and a solid salt cake. The ZLD solids would be disposed of at an approved off-site facility (HECA 2012bb, §A116). See the **Waste Management** section of this **PSA/DEIS** of this document for further analysis of the ZLD waste and disposal mitigation.

HECA: Sanitary Waste

No municipal sanitary sewer system is available in the vicinity of the project site. Sanitary wastewater from restrooms, showers, and kitchens would be disposed to a private onsite sewage disposal system consisting of a conventional septic tank and leach field (HECA 2012bb, §A116).

CO_2-EOR Component

All water to be injected would be produced water from the Elk Hills Oil Field, which would be treated in-field to remove trace oil and reinjected (OXY 2012e). The Satellite Gathering Stations would provide primary separation of the oil/water and gas from the production well stream. After separation, the gas and oil/water would flow separately via the infield gathering lines to the main process units for further processing. The liquid would flow to the CTB where the oil and water would be separated. The oil would be pumped to the existing oil shipment facility for export and sale. Produced water would then be treated at the water treatment portion of the CTB to remove oil, solids and other contaminants. It would then be pressurized in the injection pumps and sent to the Satellites Gathering Stations for reinjection. All produced water would be reused in the reinjection process (OXY 2012f, Attach A177-2).

Because no municipal sanitary sewer system is available in the vicinity of the project site, sanitary wastewater during construction would use portable chemical toilets. A sanitary waste contractor would pump and dispose the sanitary waste offsite (OXY 2012f, Attach A177-2). After permanent onsite facilities are constructed, sanitary waste would be disposed to an onsite sewage disposal system consisting of a conventional septic tank (OXY 2012f, Attach A177-4).

Contaminated Soil and Groundwater

HECA

The applicant conducted a Phase I Environmental Site Investigation for the proposed HECA site in 2009. Two Recognized Environmental Concerns (RECs) were identified on site. A standpipe, which may be associated with an underground storage tank (UST), was observed at the northwest corner of the site. Records also indicate that other USTs may be present either on or adjacent to the project site (HECA 2012e, App. L).

The Port Organic Products, LTD (PO) fertilizer manufacturing plant is located in the northwest corner of Section 10, Township 30 South, Range 24 East, directly adjacent to the propped project site. Approximately 0.8 acres of the PO facility lies within the HECA property boundary. The PO facility contains no solid waste storage; historically PO hired a contractor to transport solid waste offsite (HECA 2012e, App. L).

The PO facility historically discharged 500 to 750 gallons per day of manufacturing liquid to an onsite drainage ditch, located at the east side of the facility. The Phase I investigation recommends that this discharge be investigated to evaluate its impact to the environment (HECA 2012e, App. L).

The PO facility contained USTs in the past and may still contain USTs, as indicated in the Phase I assessment. The site has a long history of violations related to hazardous materials storage. The Kern County Environmental Health Services Department (KCEHSD) issued multiple Notices of Violation (NOVs) to PO within the last ten years. On January 31, 2009, PO's lease of the property expired. The status of site cleanup and the extent of soil contamination are still under investigation.

CO_2-EOR Component

After the sale of the Elk Hills Oil Field to OEHI, the California Department of Toxic Substances Control (DTSC) completed a Resource Conservation and Recovery Act (RCRA) Facility Assessment of the oil field in 1998. The Department of Energy (DOE) agreed to head up an environmental and human health risk assessment of the entire site with remediation to address the effects of past practices at the site. DOE and DTSC signed a Corrective Action Consent Agreement to complete the work for the assessment of 131 Areas of Concern (AOCs), which consists of both small and large areas of contamination. The work was stalled for seven years. In December 2011 and early 2012, DOE representatives submitted numerous Pre-Decisional Project Approach documents. The documents include an "overview of the planned approach to achieve site closure" for each of the 131 AOCs (HECA 2012s, §A121). For further discussion of potentially contaminated soil at the CO_2-EOR component, refer to the **Waste Management** section of this **PSA/DEIS**.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

This section provides an evaluation of the expected direct, indirect, and cumulative impacts to soil and water resources that could be caused by construction, operation, and maintenance of HECA. Staff's analysis consists of a description of the potentially significant impact, gathering data related to construction and operation of the project, then reaching a conclusion to determine whether or not the project presents a potentially significant impact. If staff determines there is a significant impact, then staff evaluates the applicants' proposed mitigation for sufficiency and staff may or may not recommend additional or entirely different mitigation measures that are potentially more effective than those proposed by the applicant. Mitigation is designed to reduce the effects of potentially significant HECA impacts to a level that is less than significant. The determination of significance for potential impacts to soil and water resources is discussed below.

METHOD FOR DETERMINING SIGNIFICANCE OF IMPACTS

This document analyzes the project's impacts pursuant to both the National Environmental Policy Act (NEPA) and CEQA. The two statutes are similar in their requirements concerning analysis of a project's impacts. Therefore, unless otherwise noted, staff's use of, and reference to, CEQA criteria and guidelines also encompasses and satisfies NEPA requirements for this environmental document.

This section provides an evaluation of the expected direct, indirect, and cumulative impacts to soil and water resources that would be caused by construction, operation, and maintenance of the project. Staff's analysis consists of a description of the potentially significant impact, gathering data related to construction and operation of the project, then reaching a conclusion to determine whether or not the project presents a potentially significant impact. If mitigation is warranted, staff provides a summary of the applicant's proposed mitigation and a discussion of the adequacy of the proposed mitigation. If necessary, staff presents additional or alternative mitigation measures and refers to specific conditions of certification related to a potential impact and the required mitigation. Mitigation is designed to reduce the effects of potential significant project impacts to a level that is less than significant.

Impacts leading to soil erosion or depletion or degradation of water resources, including beneficial uses, are among those staff believes could be most potentially significant soil and water resource issues associated with the proposed project. The determination of significance for these issues is discussed below.

SOIL RESOURCES

Staff evaluated the potential impacts to soil resources including the effects of construction and operation activities that could result in erosion and downstream transportation of soils and the potential contamination of soil and water resources. There are extensive regulatory programs in effect designed to prevent or minimize these types of impacts. These programs are effective, and absent unusual circumstances, an applicant's ability to identify and implement Best Management Practices (BMPs) to prevent erosion or contamination is sufficient to ensure that these impacts would be less than significant. The LORS and policies presented in **Soil & Surface Water Table 1** were used to determine the significance of project impacts with respect to CEQA.

WATER RESOURCES

Staff evaluated the potential of the project's proposed water use to cause a substantial depletion or degradation of groundwater resources, including beneficial uses. Staff considered compliance with the LORS and policies presented in **Soil & Surface Water Table 1** and whether there would be a significant impact under CEQA.

To evaluate if significant CEQA impacts to soil or water resources would occur, the following questions were addressed. Where a potentially significant impact was identified, staff or the applicant proposed mitigation to ensure the impacts would be less than significant.

a. Would the project substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or substantially increase the rate or amount of surface runoff in a manner which would result in flooding or substantial erosion or siltation on or offsite?

b. Would the project create or contribute runoff water that would exceed the capacity of existing or planned storm water drainage systems or provide substantial additional sources of polluted runoff?

c. Would the project place housing within a 100-year flood hazard area as mapped on the federal Flood Hazard Boundary or Flood Insurance Rate Map or other flood hazard delineation map?

d. Would the project place within a 100-year flood hazard area structures that would impede or redirect flood flows?

e. Would the project expose people or structures to a significant risk or loss, injury or death involving flooding, including flooding as a result of the failure of a levee or dam?

f. Would the project result in substantial soil erosion or the loss of topsoil?

g. Would the project violate any water quality standards or waste discharge requirements?

h. Would the project cause substantial degradation to surface water or groundwater quality?

DIRECT IMPACTS

Soil Erosion Due to Water and Wind

Erosion during Construction

Soil losses would be created by construction and grading activities that would expose and disturb the soil and leave soil particles vulnerable to detachment by wind and water. Soil erosion results in the loss of topsoil and increases in sediment loading to nearby water resources. In the absence of proper BMPs, earthwork could cause significant fugitive dust and erosion.

The magnitude, extent, and duration of those impacts would depend on several factors, including weather patterns in the vicinity of the HECA site, the types of soil that could be affected, and the method, duration, and time of year of construction activities. Prolonged periods of precipitation, or high intensity and short duration runoff events coupled with earth disturbance activities could result in accelerated onsite erosion. In addition, high winds during grading and excavation activities could cause wind borne erosion leading to increased particulate emissions that adversely impact air quality. The implementation of appropriate erosion control measures would help conserve soil resources, maintain water quality, prevent accelerated soil loss, and protect air quality.

HECA Site and Laydown Areas

Construction of HECA is scheduled to last 42 months (HECA 2012e, §2.7.1). The potential for erosion by water during construction is expected to increase as a result of loss of vegetative cover and increased local sediment transport through creation of localized gullies and rills on newly graded areas. The applicant submitted a Draft Drainage, Erosion, and Sedimentation Control Plan ([DESCP] HECA 2012bb, §A116) that lists standard BMPs applicable to HECA construction activities along with a Conceptual Erosion Control Plan that show locations of specific BMPs at the proposed project site and the adjacent temporary construction laydown area. In addition, the DESCP identifies specific measures to reduce erosion including:

- tracking weather conditions and maintaining soil stabilization of disturbed areas prior to and during rain events.
- arranging the construction schedule as much as practicable to leave existing vegetation undisturbed until immediately prior to grading; and
- placing temporary soil stabilization and sediment control measures as soon as possible after grading, and permanent erosion control as soon as possible after construction is complete.

At the end of construction, temporary disturbance areas would be cleaned up and restored to their pre-construction conditions (HECA 2012bb, §A116).

Staff concurs with the applicant that soil types at the proposed HECA site fall under Hydrologic Soil Group C, having low infiltration with moderate to high runoff, and Wind Erodibility Group 7, having a low potential for wind erosion. Staff reviewed the Draft DESCP and agrees that BMPs during construction would reduce or avoid impacts to soil from erosion. To protect surface waters, standardized storm water and soil erosion Best Management Practices (BMPs)[14] have been determined by the SWRCB and RWQCBs to be the most effective, practical means of preventing or reducing pollution from nonpoint sources. The conceptual plans for erosion control during construction appear reasonable, but as project plans approach final design stages any additional elements should be incorporated into the final DESCP as required in Condition of Certification **SOILS-1**.

Staff believes that compliance with an approved DESCP in accordance with Condition of Certification **SOILS-1** would reduce the impacts of soil erosion during construction. Staff believes the applicant should be required to comply with Condition of Certification **SOILS-1** which would require the applicant to identify the specific BMPs that would be used in the Final DESCP for staff's approval. In addition, the project activities require that it be covered under the federal General Construction Permit (SWRCB Order No. 2009-0009-DWQ), which would be issued by the State Water Resources Control Board (SWRCB) prior to construction. To ensure compliance with this order, staff proposes Condition of Certification **SOILS-2** which requires the applicant to implement a construction Storm Water Pollution Prevention Plan (SWPPP). The SWPPP would specify BMPs that would prevent all construction pollutants including erosion products from contacting storm water, eliminate or reduce non-storm water discharges to waters

[14] BMPs can be classified as "structural" (i.e., devices installed or constructed on a site) or "non-structural" (procedures, such as modified landscaping practices). There are a variety of BMPs available, depending on pollutant removal capabilities.

of the United States, and provide for inspection and monitoring of BMPs. Also, Conditions of Certification in the **Air Quality** section of this **PSA/DEIS** require a construction mitigation plan to prevent significant impacts from fugitive dust and wind erosion during construction. With implementation of BMPs and associated monitoring activities included in the approved DESCP and SWPPP, impacts on soil erosion would be expected to be less than significant during construction of the proposed HECA site.

Linear Facilities

Construction of proposed linear facilities would include installation of approximately 32 miles total of underground pipelines, as well as construction of a transmission line and an industrial railroad spur. Soil disturbance required for linear facilities would account for about 35 percent of total soil disturbance during construction, spanning across a number of different soil types (see **Soil & Surface Water Figure 8**). The runoff potential, water erosion hazard, and wind erosion hazard are shown below in **Soil & Surface Water Table 4**.

Soil & Surface Water Table 4
Soils Characteristics at Linear Facilities

Linear Facility	Temporary Disturbance (acres)	Runoff Potential	Water Erosion	Wind Erosion
Electrical transmission line	7.35	high	moderate	low
Natural gas pipeline	47.43	very high to very low	low to high	low to high
BVWSD well field and process water pipeline	90.25	high	moderate	low
Potable water pipeline	Included with transmission line	high	moderate	low
Railroad spur (single track railroad approx. 5.3 miles)	51	high	moderate	low
PG&E switching station	4	high	moderate	low
OEHI carbon dioxide pipeline	29	negligible to high	moderate	low to high
OEHI EOR Processing Facility	63.79	medium	moderate	somewhat low

Sources: HECA 2013u, §A211; U.S. Dept of Agriculture: http://websoilsurvey.nrcs.usda.gov

Activities such as clearing vegetation, excavation, and vehicle travel would present the highest potential for erosion. The proposed route of the railroad spur crosses one existing irrigation canal (East Side Canal) managed by BVWSD. The applicant states that they would work with BVWSD to engineer an appropriate canal crossing and secure the appropriate approvals. For pipeline construction, the applicant proposes a number of construction BMPs to reduce impacts to soil erosion such as:

- avoid sensitive habitats and species during construction by developing construction exclusion zones and silt fencing in sensitive areas
- provide worker environmental awareness training for all construction personnel
- general avoidance of wetland/stream impacts
- revegetation and restoration of disturbed areas
- implement specific BMPs for construction activities near sensitive areas, as described below.

Horizontal Directional Drilling Activities

Horizontal Directional Drilling (HDD) is used to avoid disturbance of sensitive areas such as water courses and wetlands. However, potential water quality impacts are associated with HDD. Those potential impacts include occasional unintended fracturing (frac-outs) of the ground above the drill resulting in a pathway through which drilling mud discharges onto the ground surface or streambed. Although generally not toxic, the drilling mud can cause turbidity impacts or coat streambed surfaces to the detriment of aquatic life. Frac-outs can sometimes be difficult to detect, particularly in streams with flowing water (See the **Biological Resources** section of this **PSA/DEIS** for further discussion on frac-outs in relation to biological resources).

The Draft DESCP states that when a proposed linear facility route crosses Interstate 5, Highway 58 and the adjacent RailAmerica railroad line, the East Side Canal, California Aqueduct, Kern River Flood Control Channel, or the West Side Canal, the pipeline may be installed under these features using HDD. The applicant has to date identified that HDD would be used to pass the CO_2 pipeline under the Outlet Canal, the Kern River Flood Control Channel (KRFCC), and the California Aqueduct (Aqueduct), as shown on **Soil & Surface Water Figure 9**. In addition, an assessment of the crossing methods to use (conventional open trenching or HDD) would be made for all water bodies, such as other irrigation canals along the pipeline route.

The Draft DESCP includes precautions that would be implemented to prevent or reduce potential damage caused by HDD activities to nearby features and the environment. Proposed BMPs include:

- conducting tunneling activities outside of wetland and riparian areas
- performing work during dry months
- preparing and implementing a Frac-Out Contingency Plan
- maintaining an on-call vacuum truck in case a spill, seep, or frac-out occurs

The depth of HDD under the water bodies would comply with all applicable federal and state regulations. Specific requirements imposed by DWR regarding the use of HDD within the right-of-way of the Aqueduct would be implemented to help protect the Aqueduct from potential damage. These requirements include: an encroachment permit from DWR, a site-specific geotechnical report, and detailed drawings to show that materials and activities meet DWR regulations and standards. The Draft DESCP lists proposed BMPs for HDD activities including:

- silt fencing around drill sites at the entry/exit pits
- energy dissipation devices for discharging water from hydrostatic testing of the pipeline
- selecting drilling fluids for environmental compatibility
- removing spent fluids from the areas immediately adjacent to water bodies
- erosion control measures to prevent runoff

Trenching Across Watercourses

Water course crossings where HDD would not be used would instead be crossed by traditional open trench methods. Potential construction-related impacts of an open trench crossing a watercourse include:

- increased sediment delivery to the water flow through disturbance of the channel bed and banks during construction;
- destabilization of the channel bed and banks resulting in long-term erosion; and
- introduction of foreign contaminants through the use of heavy machinery in the channel.

The applicant proposes in the Draft DESCP to implement practices to reduce impact when crossing watercourses including:

- when feasible, crossing canals using dry-ditch techniques when the canal is dry
- if water is present at the time of crossing a canal, evaluating individual sites to determine if conventional opencut, flume variation of open-cut, or dam and pump variation of open-cut would be used
- limiting the amount of vegetation cleared between the waterbody and the work area and minimize the amount of extra work space near canal crossings to the greatest extent possible
- restoring canals and banks to preconstruction contours or to a stable angle of repose

Staff reviewed the Draft DESCP and agrees that proposed measures would reduce impacts to soil from erosion. However, staff recommends compliance with Condition of Certification **SOILS-1** that requires the applicant to show all locations of HDD activities in the final DESCP, rather than only stating possible locations. This way, staff can verify the proximity of potential resources at and in the vicinity of HDD activities. Staff asks the applicant to provide additional information, as specified in the "Outstanding Information" under the **Staff Conclusions** heading below.

Also, Condition of Certification **BIO-16** requires an approved HDD Plan, including proposed BMPs around entrance/exit pits and a frac-out contingency plan to ensure HDD activities would not significantly impact biological resources. With implementation of these Conditions of Certification, impacts on soil would be expected to be less than significant during construction of linear facilities of HECA. Condition of Certification **SOILS-3** would ensure that the applicant meets encroachment requirements where linear facilities cross features owned by the other agencies, such as Department of Water Resources, the Central Valley Flood Protection Board, Buena Vista Water Storage District, Caltrans, and Kern County.

CO_2-EOR Component

Initial construction of the CO_2-EOR component is expected to take about two years, which includes Phase 1 of the CO_2-EOR processing facility and three Satellite Gathering Stations (OXY 2012f, Attach A177-2). These activities are subject to federal, state, and local requirements that would work together to reduce the amount of potential soil erosion during construction activities:

- Federal Clean Water Act (enforced by the State Water Resources Control Board) through a Construction General Permit
- San Joaquin Valley Air Pollution Control District's Rule 8021 to reduce fugitive dust emissions
- Kern County grading and drainage ordinances

Mitigation measures proposed by OEHI include (HECA 2012e, Vol. II):

- All disturbed areas, including storage piles, which are not being actively utilized for construction purposes, shall be effectively stabilized of dust emissions using water, chemical stabilizer/suppressant, covered with a tarp or other suitable cover or vegetative ground cover.
- All on-site unpaved roads shall be effectively stabilized of dust emissions using water or chemical stabilizer/suppressant.
- All land clearing, grubbing, scraping, excavation, land leveling, grading, cut and fill, and demolition activities shall be effectively controlled of fugitive dust emissions utilizing application of water or by presoaking.
- Suspend excavation and grading activity when winds exceed 20 mph
- Storm Water Compliance Plan would be implemented to reduce erosion.
- The project would be designed to minimize the footprint of new disturbed area by attempting to use as many existing wells and pipelines in previously disturbed acreage as much as possible.

With implementation of these applicable LORS, impacts on soil would be expected to be less than significant during the initial construction phases of the proposed CO_2-EOR component.

Erosion during Operations

Soil losses could be ongoing after the construction of the project. Areas disturbed during the construction phase are subject to potential erosion during the operational life of the proposed project. HECA would be designed for an operating life of 25 years, and the CO_2-EOR component is expected to have an operating lifespan of 20 to 40 years.

HECA: Onsite Erosion

The estimated total area of land grading and excavation during construction of the HECA site and laydown area would be about 544 acres, as shown in **Soil & Surface Water Table 2**. After project completion, the temporary parking and construction laydown areas outside of the process areas would be restored to preconstruction conditions and about 131 acres would become impervious due to the addition of concrete foundations and asphalt paving (HECA 2012bb, §A116). The balance of the previously disturbed area, roughly 413 acres, would be susceptible to potential erosion during the operational life of HECA.

The Draft DESCP states that a combination of landscaped and hydroseeding areas would be implemented as permanent erosion control measures to reduce potential soil related impacts. Landscaped areas would be irrigated and consist of a variety of vegetation and density that would comply with the Kern County ordinance. Hydroseeding would be used in open areas outside of the process and building areas where no landscaped areas are planned. These drought-resistant plants would consist of perennial/annual native plants that would protect the open areas and berm from wind or surface runoff erosion. These plants would be low maintenance after establishment.

Staff agrees that implementation and maintenance of permanent BMPs after project completion would prevent or reduce impacts to onsite soil from erosion. Staff believes compliance with the Condition of Certification **SOILS-1** which would require the applicant to develop and implement an approved DESCP would reduce the impacts of soil erosion during operation of the proposed project.

HECA: Offsite Erosion

The project’s increase of impervious area to the site could potentially increase velocities of storm water runoff leaving its boundaries, possibly increasing the potential to erode offsite areas downstream of the project. To prevent an increase in storm water flows discharged offsite, the applicant proposes to retain all storm water onsite with nine retention basins located throughout the project site. Staff agrees with the applicant that the project’s impacts to offsite soil erosion during operations would be less than significant.

CO_2-EOR Component

Different areas within the CO_2-EOR site would be disturbed at different times during the 20 year construction phase of the proposed project (HECA 2012e, Vol. II). Installation of systems would start in the eastern portion of the CO_2-EOR site, then the other ten systems would be added over time and progress westerly as reservoir development evolves. Approximately 10 to 12 years after startup, injection systems will be installed in the northwest area (OXY 2012f, Attach A177-2).

As construction activities continue after the initial phases of the CO_2-EOR component begins operations, the potential for soil erosion impacts would also continue. Because these activities are still subject to requirements as discussed above (see "Erosion during Construction"), mitigation measures would be implemented. Therefore, impacts on soil would be less than significant during continued construction and expansion of the proposed CO_2-EOR component.

Water Quality of Surface Waters

HECA and CO_2-EOR component could have an adverse effect on water quality if discharges create pollution, contamination, or nuisance. Construction and operation of an industrial facility can impact the quality of surface waters by any of the following activities:

- Sediment Increase - Grading or clearing of land so that sediment is discharged into a water resource. Sediment is considered a pollutant with potential to cause or contribute to the degradation of a water resource's beneficial uses.
- Impervious Area Increase - Increasing impervious surface areas resulting in increased amount of storm water runoff volume and rate. This can cause substantial flooding, erosion, and/or siltation, which could impact water resources.
- Aquatic Resources Impacts - Placing development in, or discharging sediment into, a river, stream, lake, wetland or water of the US and/or water of the state[15], or into a buffer area for one of these water bodies. Impacts or losses to these special aquatic resources may require specific mitigation measures.
- Polluted Runoff - Storing equipment, raw materials, finished products, or waste products in a manner that exposes them to precipitation and/or storm water runoff. Contact runoff could concentrate various pollutants that would then discharge to a water resource.
- Operation Wastewater - Discharging wastewater from an industrial or commercial process. Because of the high concentrations of total dissolved solids and the further concentration through evaporation, the liquids could be considered "designated wastes" with regulated disposal requirements.

The following discussion analyzes project information to determine whether HECA would sufficiently avoid or reduce the potential impacts listed above. Where appropriate,

[15] Refer to the **Biological Resources** section of this **PSA/DEIS** for further discussion on jurisdictional determination of wetlands or watercourses as a Water of the US or a Water of the State.

staff recommends conditions of certification to ensure that any impacts are less than significant and the project complies with applicable LORS.

Sediment Increase

To prevent the discharge of sediment, HECA would implement temporary BMPs during construction and permanent BMPs during operation to prevent or reduce soil erosion, as discussed in "Soil Erosion Due to Water and Wind" above. The SWRCB and RWQCBs have determined that standardized storm water and soil erosion BMPs are the most effective, practical means to protect surface waters by preventing or reducing pollution from nonpoint sources. Staff agrees that carefully chosen BMPs for both construction and operation activities could effectively prevent or reduce sediment discharge into water resources. Staff believes compliance with the conditions of certification relating to soil erosion (identified in the "Soil Erosion Due to Water and Wind" discussion above) would ensure that the impact of sediment to surface water quality would be less than significant.

Similarly, the CO_2-EOR component would implement mitigation measures required by federal, state, and county LORS, as discussed in "Soil Erosion Due to Water and Wind" above. The project would be designed to minimize the footprint of new disturbed areas by attempting to use as many existing wells and pipelines in previously disturbed acreage as much as possible. The short-term increases in erosion as a result of continued ground disturbance would be minimized through implementation of the project-specific Storm Water Compliance Plan. In addition, the project would comply with Kern County grading and drainage ordinances (HECA 2012e, Vol. II). Therefore, impact of increased sediment to surface water quality would be less than significant.

Impervious Area

Construction of the proposed HECA site would increase the project site's impervious area, from three percent prior to construction to 29 percent after construction. As a result, the post-construction runoff would greatly exceed pre-construction runoff due to the increase of impervious areas. To prevent an increase in storm water flows discharged offsite, the applicant proposes to retain all storm water onsite with nine retention basins located throughout the project site.

The applicant submitted a Preliminary Hydrology Study (HECA 2012bb, §A116) which conducted an onsite investigation of the HECA area's hydrology and performed computer modeling of both pre-construction and post-construction storm flows. Drainage features would be designed in accordance with Kern County's Development Standards and the Kern County Hydrology Manual. Because the applicant's storm water system of retention basins would prevent flows from leaving the site boundaries, staff does not identify any significant impacts to water quality as a result of added impervious surfaces.

Descriptions of the CO_2-EOR component state that the main processing facility would result in 101.8 acres of permanent disturbance (HECA 2012e, Vol. II). Because a site layout or other information was not provided, staff could not determine the amount of this area that would become impervious[16]. However, the proposed project must comply with Kern County grading and drainage ordinances, which would reduce impacts from increased impervious areas. Considering the relatively low annual rainfall to Elk Hills and the absence of tributary streams connecting to offsite water resources, in addition to compliance with Kern County LORS, staff expects impacts to water quality as a result of added impervious surfaces would be reduced to less than significant.

Aquatic Resources

To avoid impacts or losses to special aquatic resources, HECA proposes to implement a Biological Resources Mitigation Implementation and Monitoring Plan during construction activities (refer to the **Biological Resources** section of this **PSA/DEIS**) in addition to implementing standardized storm water and soil erosion BMPs. Plan details are still unknown pending the identification of specific mitigation and monitoring requirements.

USACOE has not yet finalized their analysis of HECA. If federal jurisdictional waters are found to be impacted, then Central Valley RWQCB would also review the project for compliance with state water quality standards. If USACOE and Central Valley RWQCB determine that additional mitigation measures would be necessary under CWA Sections 404 and/or 401, staff anticipates that compliance with those measures would address impacts to special aquatic resources and water quality. In the **Biological Resources** section , staff recommends the applicant be required to provide a copy of the 404 and/or 401 Certifications, in accordance with Condition of Certification **BIO-5** (Biological Resources Mitigation Implementation & Monitoring Plan). See the **Biological Resources** section of the **PSA/DEIS** for a discussion of potential impacts and mitigation.

Potential impacts of the CO_2-EOR component to the natural drainage ways, associated riparian vegetation, and the wildlife that depend on them could occur from increased sediment from storm water runoff. As discussed above, potential increases in erosion from ground disturbance would be minimized through implementation of the project-specific OEHI Storm Water Compliance Plan. The project would be designed to minimize the footprint of new disturbed areas by attempting to use as many existing wells and pipelines in previously disturbed acreage as much as possible (HECA 2012e, Vol. II). The project must also comply with Kern County grading and drainage ordinances.

For these reasons, staff expects impacts to aquatic resources as a result of increased sediments would be reduced to less than significant.

In addition, OEHI presently implements mitigation measures to protect biological resources through existing biological permits (for more details, see the **Biological**

[16] The submitted Biological Assessment states that the size of the EOR processing facility would be 60.61 acres (HECA 2013u, Attch A56-1). Permanent disturbed areas could include gravel surfaces, unpaved compacted soil, revegetated areas, and other surfaces that allow rainfall to infiltrate into the soil. However, no specific information was given to the percentage of the area that would be impervious.

Resources section of the **PSA/DEIS**). Staff recommends that OEHI continue to implement these measures for the proposed CO_2-EOR component or as permits are amended as required by the wildlife agencies.

Polluted Runoff

To prevent contact runoff from discharging offsite during HECA construction activities, the applicant has identified a combination of standard BMPs within the Draft Drainage, Erosion, and Sedimentation Control Plan (DESCP) for pollution control measures to be implemented during construction. The BMPs would limit or reduce potential pollutants at their source before they come into contact with storm water. These BMPs also involve daily activities of the construction site, are under the control of the construction contractor, and are additional “good housekeeping practices,” which involve maintaining a clean and orderly construction site. In addition, site drainage during construction activities would be designed to prevent runoff from leaving the site.

Staff agrees that implementation and maintenance of the identified BMPs during construction of HECA would reduce or avoid impacts of contact runoff. To ensure that an updated plan would be implemented to the final project design, staff recommends Conditions of Certification **SOILS-1** and **SOILS-2** requiring an approved DESCP and Construction SWPPP. With these conditions of certification, impacts from polluted runoff would be avoided or reduced to less than significant during construction of HECA.

To prevent contact runoff from polluting offsite resources during operations, HECA would completely separate potentially polluted contact storm water from non-contact storm water (see the “Operation Wastewater” discussion below), the project would route the collected water from potentially contaminated areas into retention basins with an impermeable liner. Water not suitable for reuse would be sent to a ZLD system with resultant solids disposed of at an approved offsite facility.

Staff agrees that implementation and maintenance of these measures would prevent contact runoff from polluting offsite resources during operations. Condition of Certification **SOILS-1** requires that the final DESCP address appropriate methods and actions for the protection of water quality and soil resources for both the construction and operation phases of the project.

Furthermore, Condition of Certification **WORKER SAFETY-2** would require a Hazardous Materials Management Program, and Condition of Certification **WASTE-8** would require an Operation Waste Management Plan. Both documents would be developed by the applicant to address handling, transportation, tracking, usage, storage, emergency response, spill control and prevention, training, record keeping, and reporting of hazardous wastes on the site. Other conditions of certification in the **Waste Management** and **Hazardous Materials Management** sections of this **PSA/DEIS** address spill prevention, cleanup of all spills of hazardous substances, and emergency response. With implementation of these conditions of certification, impacts from polluted runoff would be avoided or reduced to less than significant during operation of HECA.

Similarly, the CO_2-EOR component would implement site-specific plans to control handling, transportation, tracking, usage, storage, emergency response, training, spill control and prevention, record keeping, and reporting of hazardous wastes on the site. The safe handling of these materials is addressed through existing OEHI hazardous materials handling practices that comply with applicable regulatory requirements (HECA 2012e, Vol. II). With these practices to reduce risks of exposing contaminants to storm water runoff, in addition to the relative remoteness of the CO_2-EOR site to surface water resources, impacts from polluted runoff would be avoided or reduced to less than significant.

Operation Wastewater

To prevent the discharge of untreated industrial wastewater or untreated sanitary wastewater from entering nearby water resources, HECA would keep the potentially polluted waste water (contact runoff, general facility drainage, process wastewater, and sanitary waste) completely separate from non-contact storm water runoff. Industrial wastewater would be treated onsite to produce demineralized and utility water. Reject water not suitable for reuse would be processed through the ZLD (see “Industrial Wastewater” discussion below). Sanitary waste would remain contained within the septic system (see “Sanitary Wastewater” discussion below). Hazardous liquids would be meticulously handled to prevent spills and accidental release (see **Hazardous Materials Management** and **Worker Safety** sections of this **PSA/DEIS**). All BMPs and conditions of certification would strive to prevent any chemical or hazardous pollutants from mixing with the "clean" storm water. With implementation of these measures, impacts from sanitary or industrial wastewater would be avoided or reduced to less than significant during operation of the proposed project.

Similarly, the CO_2-EOR component would prevent discharge of untreated industrial wastewater or untreated sanitary wastewater from entering surface water resources. All produced water would be reused in the reinjection process (see “Industrial Wastewater” discussion below). Sanitary waste would remain contained within the septic system (see “Sanitary Wastewater” discussion below). Chemical or hazardous pollutants would be meticulously handled to prevent spills, accidental release, or mixing with the "clean" storm water. With implementation of these measures, impacts from sanitary or industrial wastewater would be avoided or reduced to less than significant during operation of the proposed project.

Flooding

HECA: Onsite Area Flooding

The post-construction runoff from the proposed HECA project site would exceed pre-construction runoff due to the increase of impervious areas. The applicant proposes to retain all storm water onsite, designing drainage features in accordance with Kern County’s Development Standards and the Kern County Hydrology Manual. The applicant submitted a Draft DESCP which includes a Preliminary Hydrology Study (HECA 2012bb, §A116). The study conducted an onsite investigation of the project area's hydrology and performed computer modeling of both pre-construction and post-construction storm flows.

Staff has reviewed the applicant's conceptual plans for managing storm water and believes the proposed design is sufficient to manage onsite drainage. Three of the unlined basins are expected to overflow excess runoff onto the site, but this excess water appears to pond onsite without leaving project boundaries. Because these particular basins would contain non-contact storm water, the overflow can infiltrate to open, revegetated areas of the site. Staff also noted that some of the lined onsite retention basins are calculated to have drawdown times that exceeds Kern County maximum of seven days[17]. The applicant states that outflow rate from the lined basins is based on the available capacity of the treatment plant or clarifier. Staff understands that the basin lining is the cause for the low drawdown times, but Kern County's limit is exceeded by weeks in one of the basin, as shown in **Soil & Surface Water Table 5**.

Soil & Surface Water Table 5:
HECA Drawdown Times for Select Basins

Storm Event	**Basin ID**	**Storage** (acre-feet)	**Drawdown[1]** (days)
10-year Storm	Basin #3	1.7	5.1
	Basin #7	3.2	9.7
	Basin #9	9.5	28.7
50-year Storm	Basin #3	2.7	8.2
	Basin #7	3.2	9.7
	Basin #9	14.9	45.0
100-year Storm	Basin #3	3.2	9.7
	Basin #7	3.8	11.5
	Basin #9	17.4	52.5

Source: HECA 2012bb, §A116
Notes:
1. Drawdown time equals the interval between the beginning of the rainfall to the time the retention basin or sump is empty.

The preliminary site drainage patterns of the proposed project (see see **Soil & Surface Water Figure 7**) appear to maintain separation of the non-contact runoff from the potentially contaminated runoff. In addition, staff believes the DESCP is reasonable and the sequence of implementing BMPs will avoid significant adverse impacts caused by onsite storm water drainage. However, staff recommends that HECA adjust the basin design and/or operations to comply with Kern County basin standards. This adjustment and new calculation would be required in the approved final DESCP and hydrology

[17] Kern County Hydrology Manual – Section 408.08.01 states that the basin must completely drain the design volume within seven days.

report. Condition of Certification **SOILS-1** requires an approved DESCP that ensures protection of water quality and soil resources of the proposed project. Staff asks the applicant to provide additional information, as specified in the "Outstanding Information" under the **Staff Conclusions** heading below.

HECA: Offsite Area Flooding

The topography in the vicinity of the proposed HECA site is relatively flat, with a very gentle slope from the southeast to the northwest. In general, the roads in the vicinity of the site are slightly raised above the agricultural fields. Tupman Road, along the eastern boundary of the site, and the levee associated with the irrigation canal south of the site create barriers that limit runoff from upstream (i.e., from the east and south) areas flowing onto the site. Similarly, the roads at the downstream edges of the site (e.g., Dairy Road along the western boundary and Adohr Road along the northern boundary) limit the amount of runoff that leaves the project site (HECA 2012e, §5.14.1.8).

The proposed project site would be graded and drained so that all runoff would be retained on-site. The increase in runoff caused by the additional impermeable surfaces would be mitigated by retention basins strategically located around the site to retain surface runoff from process and open areas. All temporary laydown areas would be restored to preconstruction conditions after construction (HECA 2012bb, §A116).

Based on a review of historical aerial photographs[18] and site reconnaissance, the applicant determined that the existing irrigation/drainage ditch crossing the project site formerly conveyed water north of the project area through an irrigation canal north of Adohr Road. The aerial photos illustrate clearly that by 1967 the portion of the canal north of Adohr Road was filled and abandoned. The canal no longer connects to the property north of the Project Site and is used only for irrigation and drainage within the Controlled Area of HECA. Therefore, filling in the canal and the on-site ditches would not impact any offsite drainage paths of adjacent properties (HECA 2012bb, §A116).

Staff reviewed the Draft DESCP and believes the proposed design adequately manages storm water from flowing offsite during both construction and operation. Because no increased flows would discharge offsite and existing drainage patterns would not be substantially altered, staff agrees that HECA would avoid significant adverse impacts which would result in offsite flooding.

Linear Facilities

Construction of proposed linear facilities would include installation of approximately 32 miles total of underground pipelines, as well as construction of a transmission line and an industrial railroad spur. Temporary soil disturbance during construction would be restored to natural existing conditions and, as a result, would not substantially increase the flooding potential to adjacent areas. Permanent disturbance for most of the proposed linear facilities would have relatively small footprints (footings for transmission

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[18] Photographs from Appendix B of the Phase I Environmental Site Assessment (HECA 2012e, App. L).

line poles, meter station, wells, valve boxes, etc.) which are not expected to substantially increase the flooding potential. However, construction of the proposed rail spur could potentially alter existing storm water drainage patterns and possibly result in increased flooding of adjacent areas.

As shown in **Soil & Surface Water Figure 5**, the proposed rail spur would be adjacent to roads, agricultural properties, and the East Side Canal. The applicant also provided information indicating proposed locations of at-grade crossing at road intersections and figures showing typical earthwork (grading, tract embankment fill, drainage ditches, etc.) for portions of the track not constructed at-grade (HECA 2013g, Attach A155-2). Although the terrain in the vicinity is generally very flat, and water is conveyed primarily through a network of irrigation ditches, staff does not have enough information to determine whether the proposed rail spur would significantly increase flooding of adjacent areas. Staff asks the applicant to provide additional information, as specified in the “Outstanding Information” under the **Staff Conclusions** heading below.

CO_2-EOR Component

The Elk Hills Oil Field contains a large number of ephemeral/intermittent streams draining the hills, but construction and operation of the proposed CO2-EOR component would not require permanently altering the course of any of the drainages (HECA 2012e, Vol. II). Because of the relatively low annual rainfall to Elk Hills and existing drainage patterns would not be substantially altered, staff agrees that proposed CO2-EOR component would avoid significant adverse impacts which would result in offsite flooding.

Vicinity Flood Hazards

Flood hazards include direct flooding due to overtopping of nearby rivers or streams resulting from severe rainstorms, or secondary flooding due to seismic activity creating tsunamis (tidal waves) or seiches (waves in inland bodies of water).

To identify the different types of flood risks for a given location, flood hazard maps were developed by the Federal Emergency Management Agency (FEMA) to identify areas prone to flooding[19]. Although the nearby Kern River Flood Control Channel (KRFCC) is within the 100-year floodplain as defined by FEMA, HECA is not. FEMA classifies the proposed HECA site location as Zone X, an area determined to be outside the 500-year flood and protected by levee from the 100-year flood. Therefore, construction of the proposed project would not impede or redirect flows from the 100-year flood. Likewise, floods resulting from most major rain events would not likely affect the site. To prevent high water levels from over topping the banks of the Kern River, flow is directed to the Aqueduct through the Intertie and any excess flows are diverted into the KRFCC.

Isabella Lake, which was formed by the construction of Isabella Dam in 1954, is located on the Kern River approximately 56 miles northeast of the proposed HECA site. A

[19] For further discussion of FEMA and potential flooding, see Flood Management under the “Setting and Existing Conditions” heading above.

seepage study conducted in 2005-2006 by the USACOE found that a section of the dam was being subjected to higher foundation pressures than originally believed from earlier studies. It concluded that the pressures in the foundation had reached levels that could lead to potential dam safety concerns. Therefore, an emergency deviation from the water control plan was implemented in 2006 to reduce the foundation pressures and provide an acceptable factor of safety. The deviation consisted of reducing the previous lake capacity during the flood-control off-season, from April through September of each year, until a more permanent solution could be implemented. This reduced the maximum storage capacity of the lake by 37 percent (ACOE 2012).

In the unlikely event a dam should fail at Lake Isabella, the HECA site is expected to experience flooding. In 2008, the USACOE completed the initial preparation of an updated map which shows the areas around metropolitan Bakersfield that would likely be flooded. Maps show that the HECA site could be inundated with approximately 2 feet of water[20], but staff is unclear if this assumes that Isabella Lake is at 100 percent maximum storage capacity (rather than the current 37 percent capacity). Onsite retention basins at the proposed site would have a negligible effect on flood depth, but the proposed power block, storage, and process areas would be constructed on foundations with elevations at approximately 2.5 feet above existing ground elevation[21]. Assuming that the inundation maps reflect Isabella Lake at 100 percent maximum storage capacity, staff believes HECA would not expose people or structures to a significant risk as a result of dam failure.

Staff agrees with the applicant that HECA would not have significant impacts pertaining to these identified flood hazards areas. In addition, the proposed CO_2-EOR component would not have significant impacts pertaining to these identified hazards because of its location in the Elk Hills. (For discussion on tsunamis, seiches, and additional potential hazards that could be caused by soil failure such as mudflow, landslide and liquefaction, see the **Geology and Paleontology** section of this **PSA/DEIS**.)

Water Supply

Refer to the **Water Supply** section of this **PSA/DEIS** for a detailed analysis of the potential effects on water supplies and groundwater quality.

Wastewater

Construction Wastewater

HECA and Linear Facilities

Improper handling or containment of construction wastewater could cause a broad dispersion of contaminants to soil, surface waters, or groundwater. For example,

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[20] Lake Isabella Flood Area. Kern County Engineering, Surveying and Permit Services. (http://esps.kerndsa.com/floodplain-management/lake-isabella-flood-area)

[21] The existing elevation of the proposed HECA site is approximately 286 feet amsl. Preliminary Plot Plan of the proposed project show that the elevations of foundation surfaces at 288.5 feet amsl (HEI 2009c).

hydrostatic testing[22] of a new pipeline can result in discharge of super-chlorinated water often used for the initial disinfection. Other constituents of concern include total dissolved solids (TDS) and total suspended solids (TSS). Discharge of any non-hazardous construction-generated wastewater would require compliance with discharge regulations.

Anticipated sources of wastewater, also referred to as non-storm water discharges, would be sanitary wastes, wash water, concrete washout water, paint wash water, and piping hydrostatic test water. Clean water used for dust control and soil compaction would not be considered wastewater because flows would not discharge offsite. The applicant submitted a Draft DESCP identifying a combination of standard BMPs for non-storm water management measures to be implemented during construction. Sanitary waste during construction activities would be contained in portable facilities and routinely disposed of at an offsite treatment/disposal facility by a licensed sanitary service. Concrete washout slurries would be discharged to a temporary washout facility and allowed to dry prior to disposal offsite. The Draft DESCP states that non-storm water discharges would be eliminated, controlled, or treated to minimize or eliminate the release of pollutants in storm water.

The applicant stated in the AFC that hydrostatic test water of the process equipment and piping would average 11,800 gallons per day over the HECA construction period and 2,000 gallons per day over the linear construction period. The hydrotesting of the process equipment and other piping is normally done toward the end of project construction after the mechanical construction is complete. The hydrotest water would be sampled and tested and disposed of in compliance with permit(s). Clean water with suitable chemistry would be routed to the storm water retention basin. Water that is not suitable for routing to the retention basin would be transported by truck to an appropriately licensed off-site treatment or disposal facility (HECA 2012e, §2.7.1.5).

Discharge of hydrostatic test water to land is regulated under SWRCB Order No. 2003-003-DWQ which specifically prohibits the discharge of hydrostatic test water unless all residual pollutant concentrations comply with groundwater quality objectives. Discharge of hydrostatic test water to surface waters would be subject to provisions of Central Valley Regional Board Order No. R5-2008-0081 (Waste Discharge Requirements for Dewatering and Other Low Threat Discharges to Surface Waters), which allows discharge of clean or relatively pollutant-free wastewaters that pose little or no threat to surface waters[23]. To ensure HECA would meet these requirements, staff recommends Condition of Certification **SOILS-4** (Construction Wastewater Discharge) requiring the project owner to obtain the appropriate permit(s) from Central Valley RWQCB and/or the SWRCB for proper wastewater disposal, in accordance with waste discharge requirements of the Clean Water Act (CWA). Adoption of Condition of Certification

[22] A hydrostatic test is a way in which leaks can be found in pressure vessels such as pipelines and plumbing. The test involves placing water, which is often dyed for visibility, in the pipe or vessel at the required pressure to ensure that it will not leak or be damaged.

[23] Discharges covered by the Order are either four months or less in duration or have an average dry weather flow of less than 0.25 million gallons per day.

SOILS-4, in addition to a complete and approved DESCP and Construction SWPPP as required in Conditions of Certification **SOILS-1** and **-2**, would reduce potential impacts from proposed management and disposal of wastewater during construction to a less than significant level.

CO_2-EOR Component

Hydrostatic test water would be produced during construction of the CO_2-EOR component, but project documents did not indicate the amount expected. The hydrostatic test water would be reused as practical, then sampled, tested, and disposed of in compliance with permit(s). Clean water with suitable chemistry would be collected in an onsite storm water basin. Water that is not suitable for routing to a storm water basin would be transported to an appropriately licensed off-site treatment or disposal facility (OXY 2012f, Attach A177-2). By complying with appropriate permit(s) from Central Valley RWQCB and/or the SWRCB for proper wastewater disposal, potential impacts from proposed management and disposal of wastewater during construction would be reduced to a less than significant level.

Industrial Wastewater

HECA

HECA has been designed to minimize wastewater. Water losses from the Plant Wastewater Treatment Unit are very small due to the incorporation of zero liquid discharge (ZLD) technology. Plant wastewater (including cooling tower blowdown, water treatment reject, evaporative cooler blowdown, and other miscellaneous drains) is evaporated and concentrated using a conventional mechanical vapor recompression brine concentrator followed by a brine crystallizer.

In some cases the ZLD sludge/solids could contain concentrations of chemicals that could be hazardous depending on water quality and cooling system operation. To ensure proper disposal of the ZLD solids, staff proposes Condition of Certification **WASTE-10** which requires that the project owner perform the appropriate tests to classify the waste and determine the appropriate method of disposal. Waste would be recycled to the greatest extent possible and non-recyclable wastes would be removed on a regular basis for disposal in a Class II landfill. With implementation of this condition of certification, impacts from industrial wastewater would be avoided or reduced to less than significant.

CO_2-EOR Component

Produced water would be treated at the water treatment portion of the CTB to remove oil, solids and other contaminants. It would then be pressurized in the injection pumps and sent to the Satellites Gathering Stations for reinjection. All produced water would be reused in the reinjection process (OXY 2012f, Attach A177-2). As a result, no produced water (industrial wastewater from the CO_2-EOR component) would discharge to any offsite surface water resources. Although the reinjection of produced water is essential to the WAG process for the CO_2-EOR component, the injection well is categorized as a "Class II" injection well and regulated under the United States Environmental Protection

Agency's (USEPA) Underground Injection Control (UIC) program. With compliance with UIC requirements for all injection wells and prohibition of direct discharges of produced water to nearby waterways, impacts from industrial wastewater would be reduced to less than significant.

Sanitary Wastewater

HECA

Because no municipal sanitary sewer system is available in the vicinity of the project site, HECA would require a septic system and leach field during operations. The use of septic tanks and leach fields for onsite treatment and disposal of domestic wastes is an established practice. However, improper construction and operation of these systems may adversely impact nearby surface and ground waters. The septic system planned for the project will contribute nitrogen to the subsurface. The amount of the contribution depends on the nitrogen concentration in the sewage effluent, volume of effluent, and subsurface processes. Key factors influencing the extent of groundwater nitrate contamination due to septic systems are 1) the nitrogen concentration in the effluent, 2) effluent volume, and 3) denitrification in the unsaturated and saturated zones.

To ensure protection of human health and the environment from improper disposal of sewage, California Plumbing Code and Central Valley RWQCB establishes specific requirements for the discharge of sewage. Included in the requirements are soil percolation standards; minimum separation/set back distances to prevent impacts to groundwater and nearby water wells; and septic tank and leach field design, sizing and construction standards to ensure adequate capacity and proper treatment and disposal of the wastewaters. Absent the Energy Commission's jurisdiction, Kern County would be responsible for permitting the construction and operation of the proposed septic system and has established requirements for such systems.

Consistent with the Energy Commission's in-lieu permit provisions, staff proposes adoption of Condition of Certification **SOILS-6** (Septic System and Leach Field Requirements) requiring compliance with the requirements of the Kern County Ordinance 14.20.050, Kern County Engineering: Division Six - Environmental Health Standards Rules and Regulations, the California Plumbing Code (CCR Title 24, Part 5), and the Central Valley RWQCB Basin Plan for all project sanitary waste disposal facilities, such as septic systems and leach fields. Adoption of Condition of Certification **SOILS-6** would both ensure compliance with LORS and, through the protectiveness provided by the County regulatory standards, reduce potential impacts from project septic systems to a less than significant level.

CO_2-EOR Component

Because no municipal sanitary sewer system is available in the vicinity of the project site, sanitary wastewater during construction would use portable chemical toilets. A sanitary waste contractor would pump and dispose the sanitary waste offsite (OXY 2012f, Attach A177-2). After permanent onsite facilities are constructed, sanitary waste would be disposed to an onsite sewage disposal system consisting of a conventional septic tank (OXY 2012f, Attach A177-4). Compliance with LORS and, through the protectiveness provided by the County regulatory standards, potential impacts from project septic systems would be reduced to a less than significant level.

Contaminated Soil and Groundwater

HECA

The Port Organics facility contained underground storage tanks (USTs) in the past and may still contain USTs, as indicated in the Phase I assessment. The site has a long history of violations related to hazardous materials storage. The Kern County Environmental Health Services Department (KCEHSD) issued multiple Notices of Violation (NOVs) to PO within the last ten years. On January 31, 2009, PO's lease of the property expired. The status of site cleanup and the extent of soil contamination is still under investigation.

In the event that construction excavation, grading, or trenching activities for the proposed project encounter potentially contaminated soils, specific waste handling, disposal, or other precautions may be necessary pursuant to hazardous waste management LORS. Staff also believes that proposed Conditions of Certification **WASTE-2** and **WASTE-3** would be adequate to address any soil or groundwater contamination contingency that may be encountered during construction of the project and would further support compliance with LORS.

CO_2-EOR Component

To ensure that contamination is not spread at the Elk Hills Oil Field and that construction workers are not exposed to hazardous materials as a result of project related activities, safety procedures should be developed and implemented for the construction of the project. All federal, state and local statutes and regulations must be complied with, and DTSC, DOE, and OEHI employees and contractors must be made aware of areas of concern/contamination. Staff recommends mitigation measures that would require OEHI to keep DOE and DTSC informed of construction areas and implement all appropriate and applicable safety measures to limit exposure to hazardous materials (See **MITIGATION MEASURE WASTE-1** in the **Waste Management** section of this **PSA/DEIS**).

Project Closure and Decommissioning

HECA

HECA is designed for an operating life of 25 years (HECA 2012e, §2.1). Facility closure can be either temporary or permanent, and closure options range from "unplanned temporary closure," with the intent of a restart at some time, to the removal of all equipment and facilities. Closure can result from two circumstances: (1) the facility is closed suddenly and/or unexpectedly because of unplanned events, such as a natural disaster or economic forces or (2) the facility is closed in a planned, orderly manner, such as at the end of its useful economic or mechanical life or due to gradual obsolescence.

In the event of a temporary or unplanned closure, HECA would be required to comply with all applicable conditions of certification, including an emergency Risk Management Plan to manage the possible release of hazardous substances present onsite (see the **Hazardous Materials** section of this **PSA/DEIS**). Depending on the expected duration of the shutdown, other appropriate measures would be taken such as removing chemicals from storage tanks or equipment.

Permanent closure (decommissioning) requires a Facility Closure Plan, as discussed in the **Facility Design** and **Compliance Conditions** sections of this **PSA/DEIS**, which would be submitted to the Energy Commission for approval prior to decommissioning. Future conditions that could affect decommissioning are largely unknown at this time; however compliance with all applicable LORS, and any local and/or regional plans would be required. The plan would address all concerns in regard to potential erosion and impacts on water quality. Refer to the **Facility Design** section of this **PSA/DEIS** for further discussion on temporary and permanent facility closure.

CO_2-EOR Component

The OEHI CO_2-EOR operations would close after all economic production of hydrocarbons has been exhausted, which is expected to be about 40 years. The closure phase consists of site decommissioning, well plugging and abandonment, and appropriate post-injection care and monitoring. In addition to those measures generally required for closure of UIC Class II wells, OEHI would conduct closure activities that demonstrate that the injected CO_2 is properly contained within the confinement zone and is not endangering human health or the environment. Closure will be conducted pursuant to a post-injection closure plan that will be performance-based and specifically tailored for the CO_2-EOR Project (OXY 2012f, Attach A177-2).

Existing water injection wells that are used for EOR purposes are categorized as “Class II” injection wells under the USEPA’s UIC program. The USEPA’s well permitting process and regulations under the UIC are designed to protect underground sources of drinking water under the Safe Drinking Water Act. In California, EOR well regulation is delegated to the Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR), the state agency that regulates statewide oil and gas activities. However, Class II well requirements are not intended for injecting CO_2 for sequestration purposes. The USEPA promulgated Class VI injection well regulations specifically tailored for wells intended for sequestering the injected CO_2. The Class VI regulations include specific requirements for the construction of new wells and retrofitting of existing wells, and also for the operation and monitoring of the wells during and after termination of the injection activities (see the **Carbon Sequestration and Greenhouse Gas Emissions** section of this **PSA/DEIS**).

Because DOGGR regulates plugging and abandonment of EOR wells, the CO_2-EOR component must comply with DOGGR requirements for temporary or permanent closure of EOR activities. To address issues pertaining to CO_2 sequestration, Energy Commission staff has developed proposed Conditions of Certification, as discussed in the **Carbon Sequestration and Greenhouse Gas Emissions** section of this

PSA/DEIS, to ensure effective CO_2 sequestration and ensure that impacts from the injection of the carbon dioxide would have no significant impacts on underground sources of drinking water.

INDIRECT IMPACTS

Indirect impacts are effects caused by the project and occurring later in time or farther removed in distance, but still reasonably foreseeable. Indirect impacts usually result from a chain of events caused by the project, intended or not.

Soil Erosion and Surface Water Quality

With any new project, possible indirect impacts affecting soil and water resources would be in response to additional construction activities. For example, additional housing could be needed to accommodate workers for construction and operation of a proposed project, or additional industrial facilities may be attracted to an area containing an established industrial facility. These in turn can further result in additional roads or other infrastructure. Potential impacts of these various resultant activities would be similar to the potential direct impacts of the project itself such as: potential erosion due to construction activities, potential flooding impacts due to structures within a 100-year flood zone or increase of impervious surfaces, potential contamination from industrial activities, and potential impacts from wastewater.

The **Socioeconomics** section of this **PSA/DEIS** discusses growth-inducing impacts, and concludes that no significant socioeconomic impacts to infrastructure is anticipated for either HECA or the OEHI CO_2-EOR component. The construction and operation workforces would not induce a substantial population growth or displacement of population, or induce substantial increases in demand for housing. The **Land Use** section of this **PSA/DEIS** did not identify growth-inducing impacts associated with any of the new proposed linear facilities or the proposed OEHI CO_2-EOR component. Based on this information, staff believes HECA and the OEHI CO_2-EOR component would not indirectly result in significant impacts to soil resources or surface water quality.

Water Supply and Groundwater Quality

Refer to the **Water Supply** section of this **PSA/DEIS** for a detailed analysis of the potential effects on groundwater supplies and groundwater quality.

CUMULATIVE IMPACT ANALYSIS

A project may result in a significant adverse cumulative impact where its effects are cumulatively considerable. "Cumulatively considerable" means that the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of reasonably foreseeable future projects (CCR, Title 14, section 15130). The construction and operation activities of the various projects could potentially overlap and result in cumulative impacts to the same resource(s).

SOIL EROSION AND SURFACE WATER QUALITY

Staff identified 42 projects in the vicinity of HECA and the CO_2-EOR component have been approved or are under review for construction. Because these projects are located in the same watershed and upstream of the Tulare dry lakebed, they have the potential to increase local soil erosion and storm water runoff. Without the use of storm water BMPs and erosion control BMPs, these changes could incrementally increase local soil erosion and storm water runoff leading to significant impacts to the quality of receiving water bodies. By complying with all applicable erosion and storm water management LORS, including the Basin Plan, HECA and the CO_2-EOR component would avoid or substantially lessen the cumulative problem[24]. The proposed project's contribution would not be "cumulatively considerable" and, thus, not significant.

WATER SUPPLY AND GROUNDWATER QUALITY

Refer to the **Water Supply** section of this **PSA/DEIS** for a detailed analysis of the potential cumulative effects on groundwater supplies and groundwater quality.

COMPLIANCE WITH LORS AND STATE POLICY

CLEAN WATER ACT, ANTIDEGRADATION POLICY, PORTER-COLOGNE WATER QUALITY CONTROL ACT, AND SWRCB ORDERS 2009-0009-DWQ, 2003-003-DWQ, AND 97-03-DWQ

The Clean Water Act (CWA) (33 USC, section 1257 et seq.) requires states to set standards to protect water quality, which include regulations of storm water and wastewater discharge during construction and operation of a facility. California established its regulations to comply with the CWA under the Porter-Cologne Water Quality Control Act. The SWRCB regulates storm water discharges associated with construction of projects affecting areas greater than or equal to 1 acre. Under Order 2009-0009-DWQ, the SWRCB has issued a National Pollutant Discharge Elimination System (NPDES) General Permit for storm water discharges associated with construction activity, Order 2003-03-DWQ is for water discharges to land that has a low threat to water quality (includes water from hydrostatic testing of pipes), and Order 97-03-DWQ is for storm water discharges associated with industrial activity. Projects qualify under these permits if specific criteria are met and an acceptable Storm Water Pollution Prevention Plan (SWPPP) is prepared and implemented after notifying the SWRCB with a Notice of Intent.

HECA would satisfy these requirements of the SWRCB and Central Valley RWQCB with the development of a DESCP in accordance with Condition of Certification **SOILS-1**, the development of construction SWPPPs in accordance with Condition of

[24] CEQA also allows the lead agency to determine that a project's contribution to a cumulative impact is not significant "if the project will comply with the requirements in a previously approved plan or mitigation program which provides specific requirements that will avoid or substantially lessen the cumulative problem … within the geographic area in which the project is located." (California Code of Regulations, Title 14, section 15064(h)(3).)

Certification **SOILS-2**, compliance with requirements for hydrostatic test water discharge in accordance with Condition of Certification **SOILS-4**.

Staff also recommends Condition of Certification **SOILS-5** requiring that HECA comply with all requirements of the General NPDES Permit for Discharges of Storm Water Associated with Industrial Activity, including the development of an Industrial SWPPP. This federal permit is not required if the facility does not discharge to Waters of the U.S. Although HECA is designed to prevent storm water discharge offsite, this may not be the case for extremely heavy rain events larger than the 100-year storm event. Documentation from the SWRCB or the RWQCB indicating that there is no requirement for a general NPDES permit for discharges of storm water associated with industrial activity would satisfy Condition of Certification **SOILS-5**.

NOTEWORTHY PUBLIC BENEFITS

Staff has not identified any noteworthy public benefits of the proposed project that are associated with soil and surface water resources.

DOE FINDINGS REGARDING DIRECT AND INDIRECT IMPACTS OF THE NO-ACTION ALTERNATIVE

Under the No-Action Alternative, Department of Energy (DOE) would not provide financial assistance to the Applicant for the HECA Project. The applicant could still elect to construct and operate its project in the absence of financial assistance from DOE, but DOE believes this is unlikely. For the purposes of analysis in the PSA/DEIS, DOE assumes the project would not be constructed under the No-Action Alternative. Accordingly, the No-Action Alternative would have no impacts associated with this resource area.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

The table below contains staff's responses to comments received pertinent to topics addressed in this section. The comments were submitted by:

- Agency – Central Valley Regional Water Quality Control Board (CVRWQCB)
- Agency – U.S. Environmental Protection Agency (USEPA)
- Intervenor – Association of Irritated Residents (AIR)
- Intervenor – HECA Neighbors
- Members of the public

Submitted by:	*COMMENT and RESPONSE*
AGENCY: Central Valley Regional Water Quality Control Board (CVRWQCB)	
Agency – CVRWQCB	Comment: (summarized) The Applicant needs to clarify how the daily volume of gasification solids from the combustion of coal and petcoke would be generated, contained,

Submitted by:	COMMENT and RESPONSE
(TN-65731) Docketed June 12, 2012	conveyed, and treated/disposed. The Applicant needs to provide additional details about the location and design of the solids handling collection facility; the solids drain sumps, and the operational procedures to remove the solids and fluid that collect in the sumps. The design of the sumps and storage area pads containing wastes may be such that submittal of a Report of Waste Discharge may be required. <u>Response</u>: The Applicant provided additional information in Data Responses A108 through A114 submitted August 2012 (HECA 2012q).
AGENCY: U.S. Environmental Protection Agency (USEPA)	
Agency – USEPA (TN-66381) Docketed July 30, 2012	<u>Comment</u>: (summarized) The environmental review process should document the project's consistency with applicable storm water permitting requirements under the Federal Clean Water Act, and should discuss specific mitigation measures that may be necessary or beneficial in reducing adverse impacts to water quality and aquatic resources. <u>Response</u>: The proposed project's consistency with applicable storm water permitting requirements under the Federal Clean Water Act is described in "Compliance with LORS and State Policy". Specific mitigation measures are discussed in "Direct Impacts" and "Proposed Conditions of Certification".
Agency – USEPA (TN-66381)	<u>Comment</u>: (summarized) The environmental review document should describe the original (natural) drainage patterns in the project locale, as well as the drainage patterns of the area during project operations. Identify and quantify all wetlands and waters of the U.S. within the study area. Identify whether any components of the proposed project are within a 50 or 100-year floodplain. <u>Response</u>: The original (natural) drainage patterns are described in "Setting and Existing Conditions". Discussion of wetlands and waters of the U.S. are included in the BIOLOGICAL RESOURCES section of this PSA/DEIS. The HECA site is located outside the 100-year floodplain (as shown on **Soil & Surface Water Figure 3**), which is also outside the 50-year floodplain.
INTERVENOR: Association of Irritated Residents (AIR)	
Intervenor – AIR (TN-66342) Docketed July 27, 2012	<u>Comment:</u> Area proposed for HECA is a floodplain with above average danger of flooding. The area has been flooded many times in the past. The rich top soil is direct evidence of many flooding episodes. One local resident commented at the DOE scoping meeting June 12 in Tupman that there were old treaties or binding agreements that say no flood waters may be diverted from the site. A careful examination of these claims must be

Submitted by:	COMMENT and RESPONSE
	made and analyzed as to their possible effect on the HECA project for the next 100 years. Rapid snow melt due to climate change gives an even greater possibility of flooding compared to recent history. Response: The proposed HECA site is located in a portion of the San Joaquin Valley that once contained the largest single block of permanent and seasonal wetlands in California. Today, these areas are heavily farmed, with all the region's streams diverted for irrigation or other purposes, except in the wettest years (DWR 2009). Because canals divert water from the Kern River upstream of Bakersfield, there is no river flow downstream of Bakersfield except during very wet years. Only when flows in the Kern River exceed the capacity of these diversion canals, water continues southwest past Bakersfield to the Buena Vista (dry) Lakebed near Tupman (KJC 2011). From there, excess flows would either be directed north to the Tulare (dry) Lake via the Kern River Flood Control Channel or in the California Aqueduct via the Kern River-California Aqueduct Intertie (Intertie) located near the Tupman. Both the Kern River Flood Control Channel and the Intertie were constructed to protect surrounding farmland and residences from flood damage. Staff researched and found no information regarding the existence of old treaties or binding agreements that say no flood water may be diverted from the proposed HECA site. In fact, the main purpose of both the Kern River Flood Control Channel and the Intertie is to divert flood water.
INTERVENOR: HECA Neighbors	
Intervenor – HECA Neighbors (TN-66249 and TN-66382) Docketed July 16, 2012 and July 30, 2012	Comment: What if the unforeseen happens… a problem with their pipes, an earthquake, an accident, or an unknown that has not been regulated yet, or something else (a spill, an explosion). Our ground water will be contaminated. Contaminated water is impossible to correct. Wells supply homes very near HECA. What is the protection? Response: Several different Conditions of Certification have been developed to require the project to address spill prevention, cleanup of all spills of hazardous substances, and emergency response. As an additional level of protection, potential spills from the power block, facilities, and processing areas would drain into sumps or lined retention basins to prevent the contaminated material from leaching into the soil.
PUBLIC COMMENTS	
Public – Antongiovanni (TN-66397)	Comment: According to multiple ground contour and elevation maps, the footprint for the HECA project sits lower in elevation than land deemed "Swamp" and "Overflowed Land"… All forms of nitrogen stored at the facility add to the damage caused by a flooding event. A flood would disperse the nitrogen

Submitted by:	COMMENT and RESPONSE
Docketed July 30, 2012	(a known ground water pollutant in the southern San Joaquin Valley) throughout the lakebed and contaminate our ground water supply. <u>Response:</u> The proposed HECA site is located in Zone X, as designated by the Federal Emergency Management Agency (FEMA). Zone X is defined as an area determined to be outside the 0.2% annual chance flood also known as the 500-year flood (the flood that has a 0.2% chance of being equaled or exceeded in any given year). In addition, the HECA site drainage is designed to retain all storm water onsite for rain events up to the 100-year storm. Project facilities and processing areas would drain into sumps or lined retention basins to prevent the contaminated material from leaching into the soil.
Public – Douglas (TN-66389) Docketed July 30, 2012	<u>Comment:</u> [The HECA project] is also on the floodplain of the Kern River. Water from our crumbling Isabella Dam would cover the site if we were to get an earthquake and/or dam failure. Last, the site backs up to the California Aqueduct; can you take a chance on endangering Southern California's water supply? <u>Response:</u> Isabella Dam is discussed in the "Vicinity Flood Hazards" under Direct Impacts. Impacts relating to earthquakes are included in the **GEOLOGY and PALEONTOLOGY** section of this **PSA/DEIS.** Although the proposed HECA site is within half-a-mile from the California Aqueduct, a system of irrigation canals (including the West Side Canal and the Outlet Canal) and the Kern River Flood Control Channel are located between them (see **Soil & Surface Water Figure 3**). Under current conditions, no water directly flows from the site to the Aqueduct. In addition, the Aqueduct was designed and constructed to prevent surrounding surface waters from flowing into the channel. Furthermore, the HECA site would be graded to drain runoff away from the Aqueduct (see **Soil & Surface Water Figure 7**) and onsite retention basins would prevent storm water runoff from leaving the site.

STAFF CONCLUSIONS

Based on the assessment of the proposed project, California Energy Commission (Energy Commission) staff concludes:

- Compliance with an approved DESCP in accordance with Condition of Certification **SOILS-1** would reduce the impacts of soil erosion during construction and operations.

- Conditions of Certification **SOILS -1**, **-2**, and **-4** would reduce or avoid impacts of contact runoff during construction activities. Conditions of Certification **SOILS -1** and **-5** would reduce or avoid impacts of contact runoff during operations.
- The discharge of construction wastewater would be in compliance with LORS and would have no adverse environmental impact provided the requirements of Condition of Certification **SOILS-4** are met.
- Condition of Certification **SOILS-3** would ensure that the applicant meets encroachment requirements where linear facilities cross features owned by other agencies, such as Department of Water Resources, the Central Valley Flood Protection Board, Buena Vista Water Storage District, Caltrans, and Kern County.
- The discharge of sanitary waste would be in compliance with LORS and would have no adverse environmental impact provided the requirements of Condition of Certification **SOILS-6** are met.
- Through Compliance with Conditions of Certification **SOILS-2** through **-6**, HECA would conform with applicable federal, state, and local LORS and state policy related to water quality and hydrology, with the exception of the Kern County basin standard (see “Outstanding Information” below).
- Staff has not identified any significant impacts that would occur regarding water quality and hydrology caused by the proposed OEHI CO_2-EOR component.
- Staff has not identified any significant adverse direct or cumulative soils or surface water impacts resulting from the construction or operation of the proposed project, including impacts to the environment justice population. Therefore, there are no soils or surface water environmental justice issues related to this project and no environmental justice populations would be significantly, adversely, or disproportionately impacted.

OUTSTANDING INFORMATION REQUIRED FOR COMPLETION OF THE FSA/FEIS

Additional Information for the draft DESCP

- The applicant has identified that HDD would be used to pass the CO_2 pipeline under the Outlet Canal, the Kern River Flood Control Channel (KRFCC), and the California Aqueduct (Aqueduct), as shown on **Soil & Surface Water Figure 9**. In addition, the draft DESCP states that an assessment of the crossing methods (conventional open trenching or HDD) would be made for all water bodies, such as irrigation canals, along other pipeline routes. If additional HDD locations are anticipated, staff needs to analyze the proximity of potential resources at and in the vicinity of these locations. Please show all potential locations of HDD activities in the DESCP and update the disturbed soil estimates of entry/exit pits. If HDD sites are not yet finalized, please be conservative and include all potential sites.
- Staff notes that some of the lined retention basins at the HECA site are calculated to have drawdown times that exceed the Kern County maximum of seven days (Kern

County Hydrology Manual – Section 408.08.01). Please adjust the basin design and/or operations to comply with the Kern County basin standard. Also revise the DESCP and hydrology report to reflect these changes.

Proposed Rail Spur Impacts to Offsite Flooding

Construction of the proposed rail spur could potentially alter existing storm water drainage patterns and possibly result in increased flooding of adjacent areas. Please provide additional information:

- Maps and drawings that show locations where construction would cross drainages, canals, and other water bodies. Identify what local and/or permits would be required for these crossings.
- Description of typical methods proposed for accommodating flows under or around the rail bed. Include maps that show locations of drainage features and indicate what flows they would be designed to handle.
- Identify whether the rail bed would be constructed in or near a FEMA 100-year floodplain Zone A. If so, discuss the measures that would be required to ensure no upstream or downstream impacts.

PROPOSED CONDITIONS OF CERTIFICATION

DRAINAGE EROSION AND SEDIMENTATION CONTROL PLAN

SOILS-1: Prior to site mobilization, the project owner shall obtain the CPM's approval for a site specific Drainage Erosion and Sedimentation Control Plan (DESCP) that ensures protection of water quality and soil resources of the project site and all linear facilities for both the construction and operation phases of the project. This plan shall address appropriate methods and actions, both temporary and permanent, for the protection of water quality and soil resources, demonstrate no increase in offsite flooding potential, and identify all monitoring and maintenance activities. The project owner shall complete all engineering plans, reports, and documents necessary for the CPM to conduct a review of the proposed project and provide a written evaluation as to whether the proposed grading, drainage improvements, and flood management activities comply with all requirements presented herein. The plan shall be consistent with the grading and drainage plan as required by Condition of Certification **CIVIL-1** and shall contain at a minimum the following elements:

Vicinity Map: A map shall be provided indicating the location of all project elements with depictions of all major geographic features to include watercourses, washes, irrigation and drainage canals, major utilities, and sensitive areas.

Site Delineation: The site and all project elements shall be delineated showing boundary lines of all construction areas and the location of all existing and proposed structures, underground utilities, roads, and drainage facilities. With legend, indicate types and locations of storm water control measures built to permanently control storm water pollution. Distinguish between pollution prevention, treatment, and containment devices. Identify sanitary waste facilities. Adjacent property owners shall be identified on the plan maps. All maps shall be presented at a legible scale.

Drainage: The DESCP shall include the following elements:

1. Topography. Topography for offsite areas is required to define the existing upstream tributary areas to the site and downstream to provide enough definition to map the existing storm water flow and flood hazard. Spot elevations shall be required where relatively flat conditions exist.

2. Proposed Grade. Proposed grade contours shall be shown at a scale appropriate for delineation of onsite ephemeral washes, drainage ditches, and tie-ins to the existing topography.

3. Hydrology. Existing and proposed hydrologic calculations for onsite areas and offsite areas that drain to the site; include maps showing the drainage area boundaries and sizes in acres, topography and typical overland flow directions, and show all existing, interim, and proposed drainage infrastructure and their intended direction of flow.

4. Hydraulics. Provide hydraulic calculations to support the selection and sizing of the onsite drainage network, diversion facilities and BMPs.

Watercourses and Critical Areas: The DESCP shall show the location of all onsite and nearby watercourses including washes, irrigation and drainage canals, and drainage ditches, and shall indicate the proximity of those features to the construction site. Maps shall identify high hazard flood prone areas.

Clearing and Grading: The plan shall provide a delineation of all areas to be cleared of vegetation and areas to be preserved. The plan shall provide elevations, slopes, locations, and extent of all proposed grading as shown by contours, cross-sections, cut/fill depths or other means. The locations of any disposal areas, fills, or other special features such as Horizontal Directional Drilling (HDD) pits shall also be shown. Existing and proposed topography tying in proposed contours with existing topography shall be illustrated. The DESCP shall include a statement of the quantities of material excavated at the site, whether such excavations or fill is temporary or permanent, and the amount of such material to be imported or exported or a statement explaining that there would be no clearing and/or grading conducted for each element of the project. Areas of no disturbance shall be properly identified and delineated on the plan maps.

Soil Wind and Water Erosion Control: The plan shall address exposed soil treatments to be used during construction and operation of the proposed project for both road and non-road surfaces including specifically identifying all chemical based dust palliatives, soil bonding, and weighting agents appropriate for use at the proposed project site that would not cause adverse effects to vegetation; BMPs shall include measures designed to prevent wind and water erosion including application of chemical dust palliatives after rough grading to limit water use. All dust palliatives, soil binders, and weighting agents shall be approved by the CPM prior to use.

Project Schedule: The DESCP shall identify on the topographic site map the location of the site-specific BMPs to be employed during each phase of construction (initial grading, project element construction, and final grading/stabilization). BMP implementation schedules shall be provided for each project element for each phase of construction.

Best Management Practices: The DESCP shall show the location, timing, and maintenance schedule of all erosion- and sediment-control BMPs to be used prior to initial grading, during project element excavation and construction, during final grading/stabilization, and after construction. BMPs shall include measures designed to control dust and stabilize construction access roads and entrances. The maintenance schedule shall include post-construction maintenance of treatment-control BMPs applied to disturbed areas following construction.

Erosion Control Drawings: The erosion-control drawings and narrative shall be designed, stamped and sealed by a professional engineer or erosion-control specialist.

Agency Comments: The DESCP shall include copies of recommendations from the Kern County and RWQCB, if applicable.

<u>Verification</u>: The DESCP shall be consistent with the grading and drainage plan as required by Condition of Certification **CIVIL-1**. In addition, the project owner shall do all of the following:

- No later than ninety (90) days prior to start of site mobilization, the project owner shall submit a copy of the DESCP to Kern County and the RWQCB for review and comment. No later than 30 days prior to the start of site mobilization, the project owner shall submit a copy of the DESCP with Kern County and RWQCB comments attached to the CPM for review and approval.
- During construction, the project owner shall provide an analysis in the monthly compliance report on the effectiveness of the drainage, erosion, and sediment control measures and the results of monitoring and maintenance activities.

- Once operational, the project owner shall provide in the annual compliance report information on the results of storm water BMP monitoring and maintenance activities.

NPDES GENERAL PERMIT FOR CONSTRUCTION ACTIVITY

SOILS-2: The project owner shall comply with the requirements of the general National Pollutant Discharge Elimination System (NPDES) permit for discharge of storm water associated with construction activity. The project owner shall submit copies of all correspondence between the project owner and the State Water Resources Control Board (SWRCB) or the Central Valley Regional Water Quality Control Board regarding this permit to the CPM. The project owner shall also develop and implement a construction Storm Water Pollution Prevention Plan (SWPPP) for construction on the HECA main site, laydown areas, linear facilities, and transmission line.

Verification: No later than thirty (30) days prior to site mobilization, the project owner shall submit a copy of the construction SWPPP to the SWRCB for review and approval, and retain a copy of the approved SWPPP on site throughout construction. The project owner shall submit copies of all correspondence between the project owner and the SWRCB or the Central Valley Water Board regarding the NPDES permit for the discharge of storm water associated with construction activity to the CPM within 10 days of its receipt or submittal. Copies of correspondence shall include the Notice of Intent sent to the SWRCB, the confirmation letter indicating receipt and acceptance of the Notice of Intent, a copy of the construction SWPPP, any permit modifications or changes, and completion/permit Notice of Termination.

ENCROACHMENT FOR LINEAR FACILITIES

SOILS-3: The project owner shall comply with relevant jurisdiction limitations for encroachment into public rights-of-way for construction activities of linear facilities and shall obtain all necessary encroachment permits from all relevant jurisdictions including, but not limited to: Department of Water Resources (California Aqueduct), Caltrans (Interstate 5, Highway 58), RailAmerica (railroad), Central Valley Flood Protection Board (Kern River Flood Control Channel), Buena Vista Water Storage District (irrigation canals), and Kern County (county roads).

Verification: No later than thirty (30) days prior to mobilization construction work of linear facilities, the project owner shall submit to the CPM copies of all necessary encroachment permits relative to construction of linear facilities, unless the permitting agency states that a permit is not required. In addition, the project owner shall retain copies of these permits and supporting documentation in its compliance file for at least six months after the start of commercial operation.

CONSTRUCTION WASTEWATER DISCHARGE

SOILS-4: Prior to hydrostatic test water discharge to land, the project owner shall fulfill the requirements contained in State Water Resources Control Board (SWRCB) *Order No. 2003-003-DWQ Statewide General Waste Discharge*

Requirements (WDRs) for Discharges to Land with a Low Threat to Water Quality (General WDRs) and all subsequent revisions and amendments.

Prior to hydrostatic test water discharge to surface waters or designated Waters of the State, the project owner shall fulfill the requirements contained in Central Valley Regional Board *Order No. R5-2008-0081 (Waste Discharge Requirements for Dewatering and Other Low Threat Discharges to Surface Waters)* and all subsequent revisions and amendments.

Prior to transport and disposal of any facility construction-related wastewaters offsite, the project owner shall test and classify the stored wastewater to determine proper management and disposal requirements. The project owner shall provide evidence that wastewater is disposed of at an appropriately licensed facility. The project owner shall ensure that the wastewater is transported and disposed of in accordance with the wastewater's characteristics and classification and all applicable LORS (including any CCR Title 22 Hazardous Waste and Title 23 Waste Discharges to Land requirements).

<u>Verification:</u> The project owner shall submit to the CPM copies of all relevant correspondence between the project owner and the SWRCB or Central Valley RWQCB about the hydrostatic test water discharge requirements within 10 days of its receipt or submittal. This information shall include copies of the Notice of Intent and Notice of Termination for the project. A letter from the SWRCB or Central Valley RWQCB indicating that there is no requirement for the discharge of hydrostatic test water would satisfy the corresponding portion of this condition.

Prior to transport and disposal of any facility construction-related wastewaters offsite, the project owner shall test and classify the stored wastewater to determine proper management and disposal requirements. The project manager shall ensure that the wastewater is transported and disposed of in accordance with the wastewater's characteristics and classification and all applicable LORS (including any CCR Title 22 Hazardous Waste and Title 23 Waste Discharges to Land requirements). The project owner shall provide evidence to the CPM of proper wastewater disposal, via a licensed hauler to an appropriately licensed facility, in the monthly compliance report.

INDUSTRIAL - NPDES GENERAL PERMIT

SOILS-5: The project owner shall comply with the requirements of the State Water Resources Control Board's NPDES General Permit for Discharges of Storm Water Associated with Industrial Activities (Order No. 97-03-DWQ, NPDES No. CAS000001) and all subsequent revisions and amendments. The project owner shall develop and implement a Storm Water Pollution Prevention Plan (SWPPP) for project operation. The project owner may also submit a Notice of Non- Applicability (NONA) to the State Water Resources Control Board (SWRCB) to apply for an exemption to the general NPDES permit.

<u>Verification</u>: At least thirty (30) days prior to operation, the project owner shall submit copies to the CPM of the operational SWPPP and shall retain a copy on site.

Within 10 days of its mailing or receipt, the project owner shall submit to the CPM any correspondence between the project owner and the SWRCB or Central Valley RWQCB about the general NPDES permit for discharge of storm water associated with this activity. This information shall include a copy of the Notice of Intent sent by the project owner to the SWRCB and the notice of termination. A letter from the SWRCB or the RWQCB indicating that there is no requirement for a general NPDES permit for discharges of storm water associated with industrial activity would satisfy this condition.

SEPTIC SYSTEM AND LEACH FIELD REQUIREMENTS

SOILS-6: The project owner shall comply with the requirements of the Kern County Ordinance 14.20.050, Kern County Engineering: Division Six - Environmental Health Standards Rules and Regulations, and the California Plumbing Code (CCR Title 24, Part 5) regarding sanitary waste disposal facilities such as septic systems and leach fields. The septic system and leach fields shall be designed, operated, and maintained in a manner that ensures no deleterious impact to groundwater or surface water. Compliance shall include an engineering report on the septic system and leach field design, operation, maintenance, and loading impact to groundwater.

Verification: The project owner shall submit the appropriate fee and required documentation to the Kern County Environmental Health Department for review and comment to ensure that the project has complied with county sanitary waste disposal facilities requirements including: soil percolation standards; minimum separation/set back distances to prevent impacts to groundwater and nearby water wells; and septic tank and leach field design, sizing and construction standards to ensure adequate capacity and proper treatment and disposal of the wastewaters. Written assessments prepared by Kern County regarding the project’s compliance with these requirements must be submitted to the CPM for review and approval at least thirty (30) days prior to use of the septic systems.

REFERENCES

ACOE 2012 – U.S. Army Corps of Engineers. Isabella Lake Dam Safety Modification Project, Environmental Impact Statement, Final. October 2012.

DWR 2009 – California Department of Water Resources. California Water Plan Update 2009 (Bulletin 160-09), Volume 3, Regional Reports: Tulare Lake. 2009.

ECORP 2007 – ECORP Consulting. Tulare Lake Basin Hydrology and Hydrography: A Summary of the Movement of Water and Aquatic Species. Prepared for U.S. Environmental Protection Agency. April 2007.

HECA 2012e – SCS Energy California, LLC (tn 65049). Amended Application for Certification; Vols. I, II, and III (08-AFC-8A), dated 05/02/12. Submitted to CEC Docket Unit on 05/02/2012.

HECA 2012q – SCS Energy California, LLC/URS/D. Shileikis (tn 66876). Response to CEC's Data Request Set 1; A1 - A123, dated 08/22/2012. Submitted to CEC Docket Unit on 08/22/2012.

HECA 2012r – SCS Energy California, LLC/URS/D. Shileikis (tn 66979). Response to Sierra Club's Data Request Nos. 1 - 97, dated 08/31/2012. Submitted to CEC Docket Unit on 08/31/2012.

HECA 2012s – SCS Energy California, LLC/URS/D. Shileikis (tn 67096). Response to CEC's Data Requests Set 1; Occidental Elk Hills, Inc., (OEHI) Extension, dated 09/12/2012. Submitted to CEC Docket Unit on 09/12/2012.

HECA 2012bb – SCS Energy California, LLC/URS/D. Shileikis (tn 67969). Response to CEC's Data Requests Set 1; 60 day extension, dated 10/22/2012. Submitted to CEC Docket Unit on 10/22/2012.

HECA 2013g – SCS Energy California, LLC/URS/D. Shileikis (tn 70013). Second Supplemental CEC: Data Requests Nos. A155 and 156, dated 3/20/2013. Submitted to CEC Docket Unit on 03/20/2013.

HECA 2013u - SCS Energy California, LLC/DOE/URS/D. Shileikis (tn 69838). Supplemental Responses to CEC Data Requests Set1; A56 and Set 3; A211 and Attachment A56-1 Biological Assessment, dated 03/05/2013. Submitted to CEC Docket Unit on 03/04/2013.

HEI 2009c - Hydrogen Energy International, LLC /J. Briggs (tn 51735). Revised Application for Certification, dated 05/28/09. Submitted to CEC/Docket Unit on 05/28/09.

KJC 2011 – Kennedy/Jenks Consultants. Tulare Lake Basin Portion of Kern County Integrated Regional Water Management Plan Final Update. Prepared for Kern County Water Agency. November 2011.

OXY 2012b – Occidental of Elk Hills, Inc (tn 67006). Draft Supplemental Environmental Impact Statement/Program Environmental Interim Report, for the Sale of the Naval Petroleum Reserve No. 1 at Elk Hills, CA., dated July 1997. Submitted to CEC Docket Unit on 09/07/2012

OXY 2012e – Occidental of Elk Hills, Inc (tn 67728). Response to CEC March 16, 2012 Data Request 1-7; OEHI to DOGGR Data Responses and MRV Plan, dated 10/15/2012. Submitted to CEC Docket Unit on 10/15/2012.

OXY 2012f – Occidental of Elk Hills, Inc (tn 68376). Response to CEC Data Request Set 2; A136 - A138 and A171 - A177, dated 11/05/2012. Submitted to CEC Docket Unit on 11/05/2012.

RWQCB 2004 – California Regional Water Quality Control Board, Central Valley Region. Water Quality Control Plan for the Tulare Lake Basin (Basin Plan) Second Edition, revised January 2004.

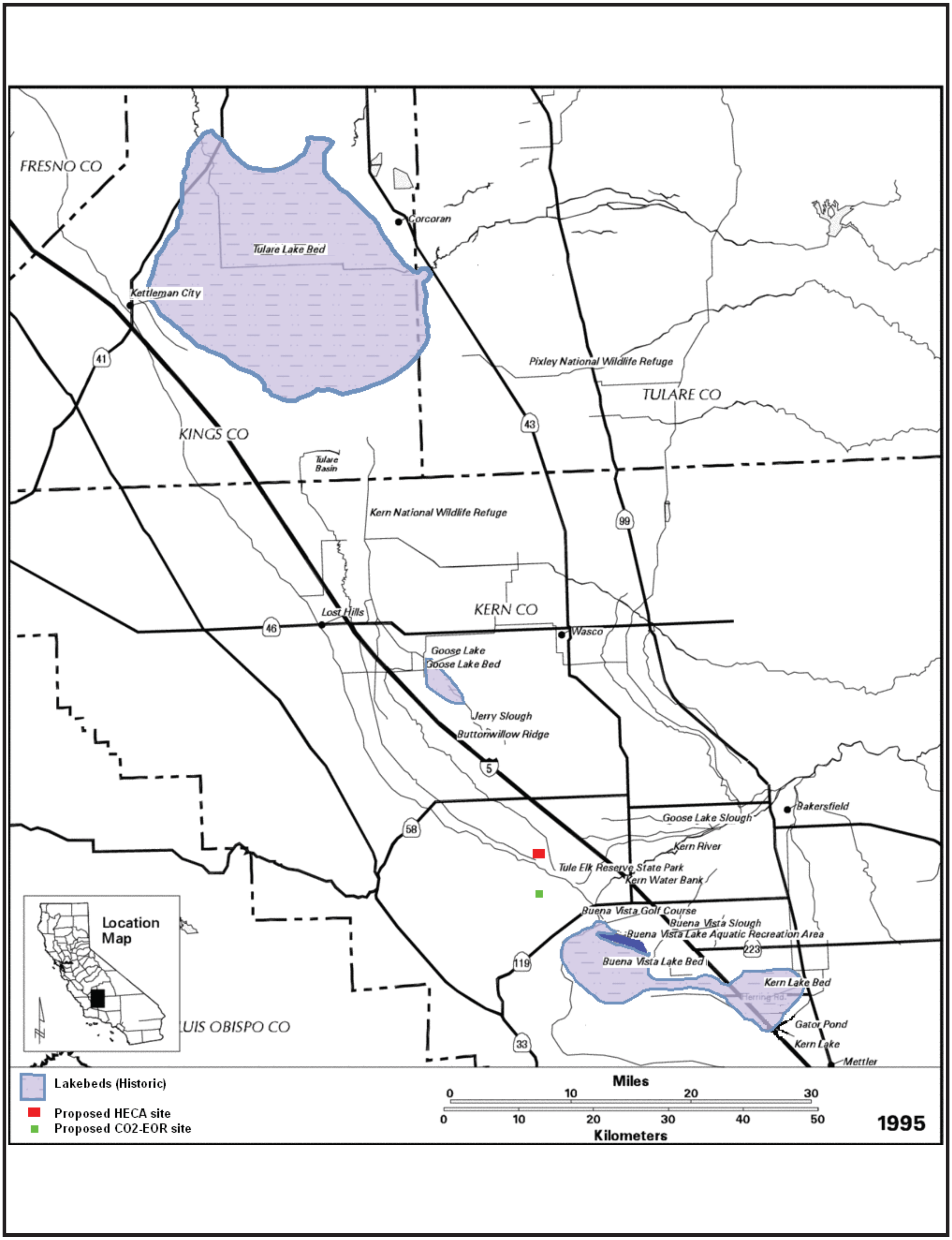
Soil and Surface Water - Appendix A

Acronyms Used in the Soil and Surface Water Section

AFC	Application for Certification
AGR	Acid gas removal
AIR	Association of Irritated Residents
amsl	above mean sea level
AOC	Areas of Concern
ASU	Air Separation Unit
BMP	Best Management Practices
BVWSD	Buena Vista Water Storage District
CBO	Chief Building Official
CCR	California Code of Regulations
CEQA	California Environmental Quality Act
CO_2	Carbon Dioxide
CPM	Compliance Project Manager
CRP	Carbon Dioxide Recovery Plant
CTB	Central Tank Battery
CVP	Central Valley Project
CVRWQCB	Central Valley Regional Water Quality Control Board
CWA	Federal Clean Water Act
CWC	California Water Code
DESCP	Drainage, Erosion, and Sediment Control Plan
DOE	Department of Energy
DOGGR	Department of Conservation, Division of Oil, Gas, and Geothermal Resources
DTSC	California Department of Toxic Substances Control
DWR	Department of Water Resources
DWR	California Department of Water Resources
EOR	Enhanced Oil Recovery
FEMA	Federal Emergency Management Agency
FEMA	Federal Emergency Management Agency
HDD	Horizontal Directional Drilling
HECA	Hydrogen Energy California
KCEHSD	Kern County Environmental Health Services Department
LORS	Laws, Ordinances, Regulations, and Standards
mph	miles per hour
MW	Megawatt
NEPA	National Environmental Policy Act
NOV	Notice of Violation
NPDES	National Pollutant Discharge Elimination System

OEHI	Occidental of Elk Hills, Inc
PG&E	Pacific Gas & Electric Company
PO	Port Organic Products, LTD
PSA	Preliminary Staff Assessment
RCF	Reinjection Compression Facility
RCRA	Resource Conservation and Recovery Act
REC	Recognized Environmental Concern
RWQCB	Regional Water Quality Control Board
SWP	State Water Project
SWPPP	Storm Water Pollution Prevention Plan
SWRCB	State Water Resources Control Board
TDS	Total Dissolved Solids
TSS	Total Suspended Solids
UAN	Urea Ammonium Nitrate
UIC	Underground Injection Control
USACOE	United States Army Corp of Engineers
USEPA	United States Environmental Protection Agency
UST	Underground Storage Tank
WAG	Water Alternating Gas
WDR	Waste Discharge Requirements
ZLD	Zero Liquid Discharge

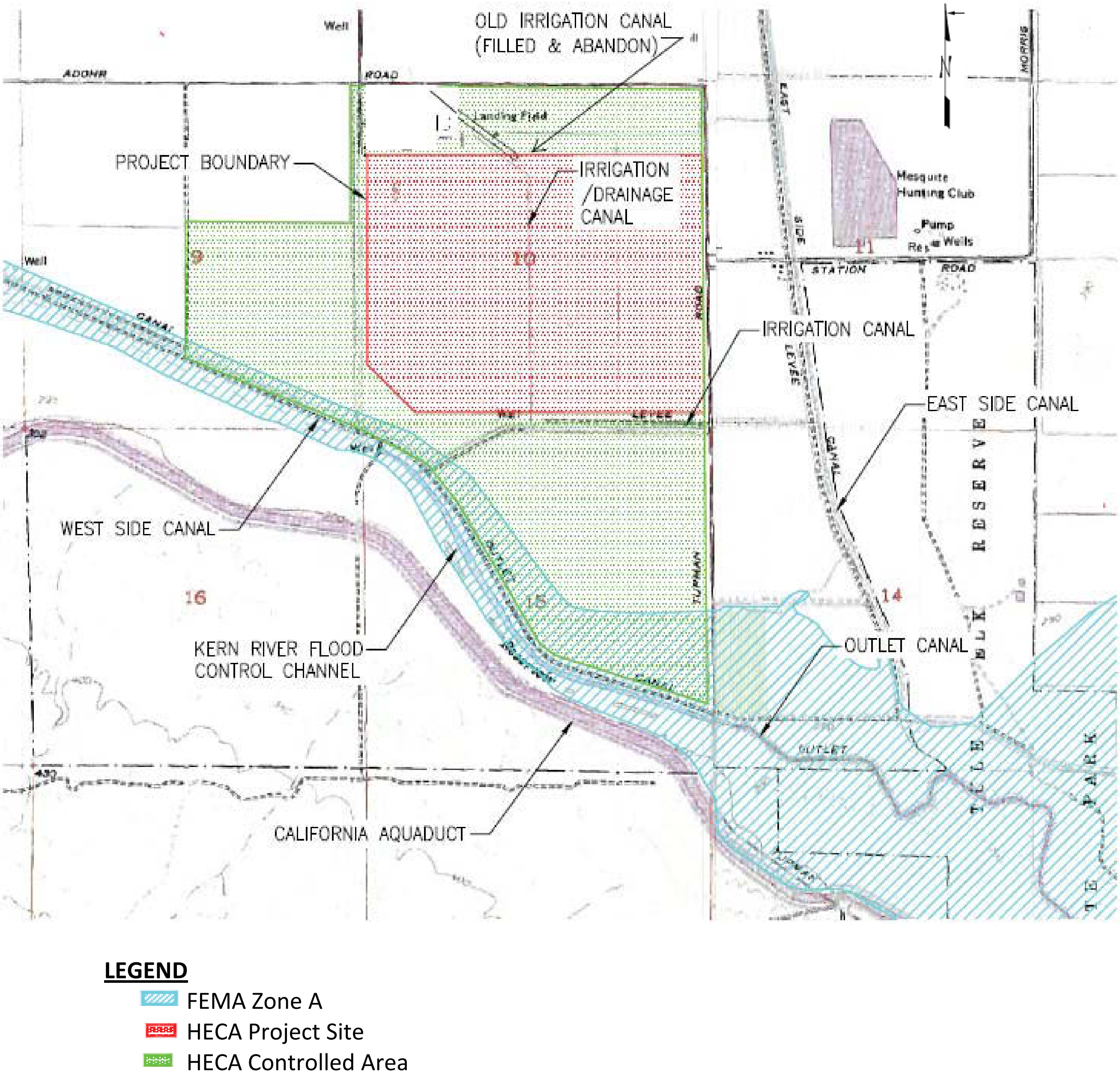
SOIL AND SURFACE WATER RESOURCES - FIGURE 1
Hydrogen Energy California (HECA) - Historic Lakebeds



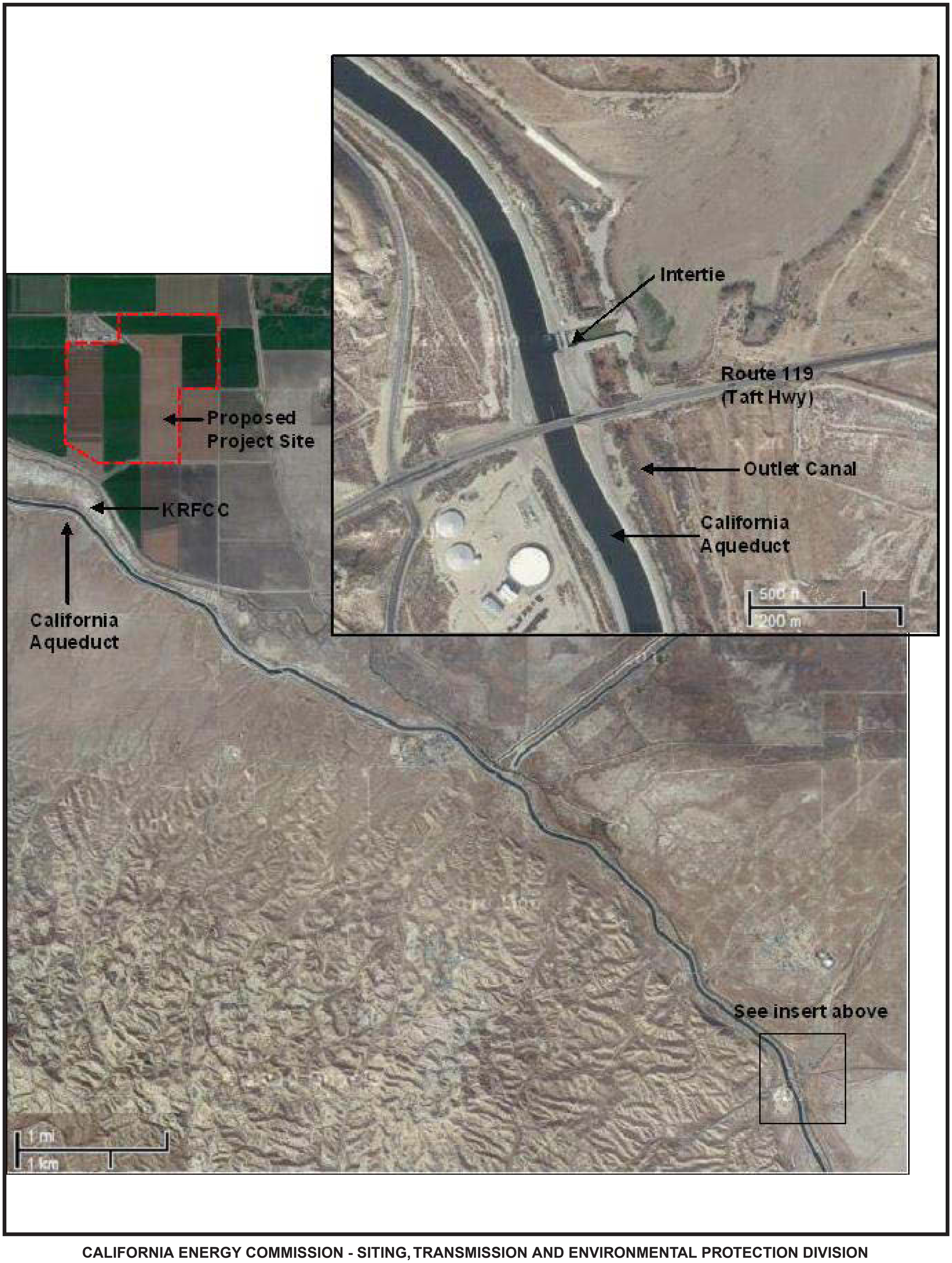
CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: CSU Stanislaus, Endangered Species Recovery Program, 2006

SOIL AND SURFACE WATER RESOURCES - FIGURE 2
Hydrogen Energy California (HECA) - Vicinity Rivers

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: http://www2.demis.nl/mapserver/mapper.asp, 2012

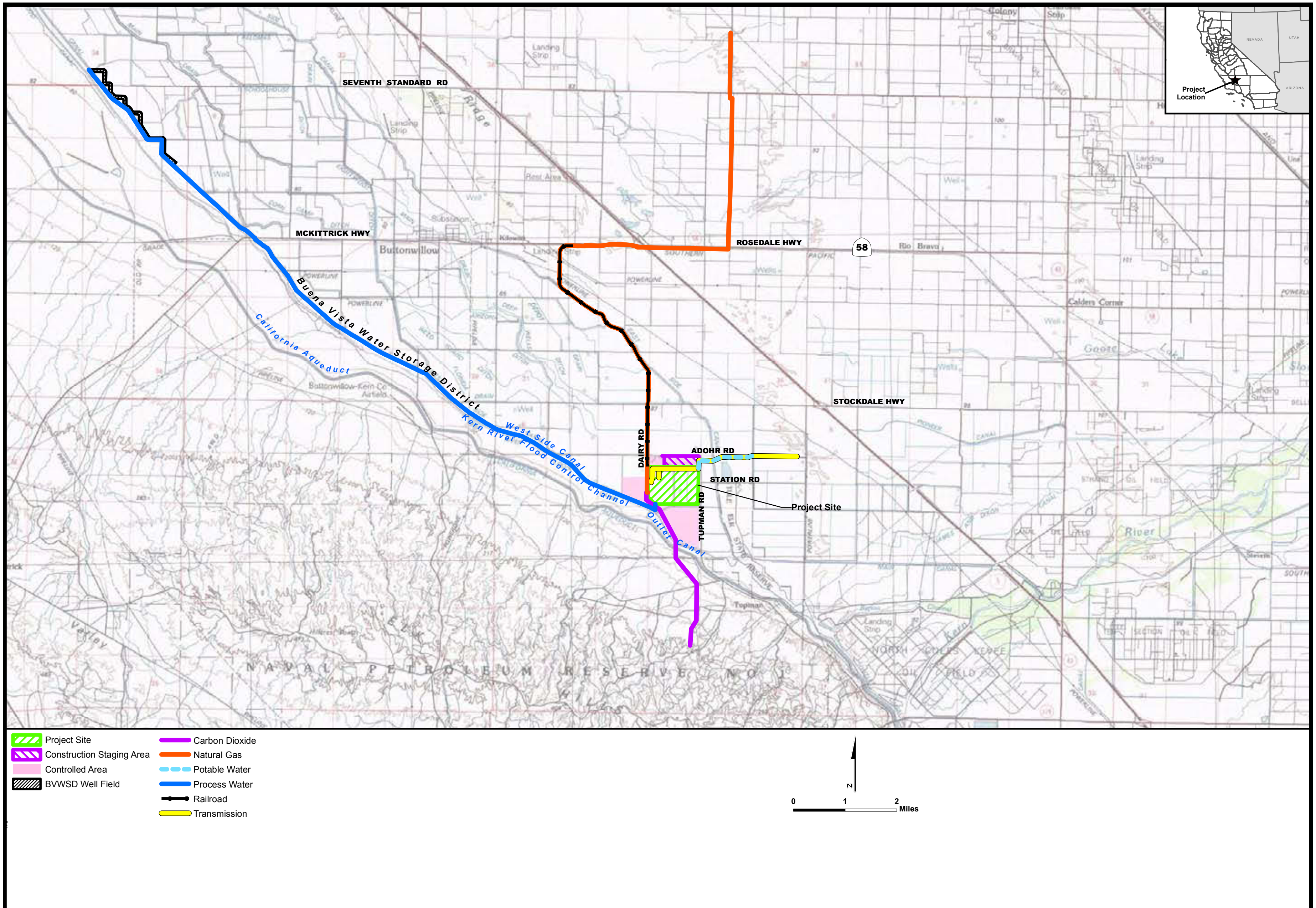

OLD IRRIGATION CANAL
(FILLED & ABANDON)
PROJECT BOUNDARY
IRRIGATION
/DRAINAGE
CANAL
IRRIGATION CANAL
EAST SIDE CANAL
WEST SIDE CANAL
KERN RIVER FLOOD
CONTROL CHANNEL
OUTLET CANAL
CALIFORNIA AQUADUCT
Mesquite
Hunting Club
N
9
10
16
15
14
LEGEND
FEMA Zone A
HECA Project Site
HECA Controlled Area

SOIL AND SURFACE WATER RESOURCES - FIGURE 4
Hydrogen Energy California (HECA) - Kern River-California Aqueduct Intertie



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: Google Maps, 2012

SOIL AND SURFACE WATER RESOURCES - FIGURE 5
Hydrogen Energy California (HECA) - Linear Facilities

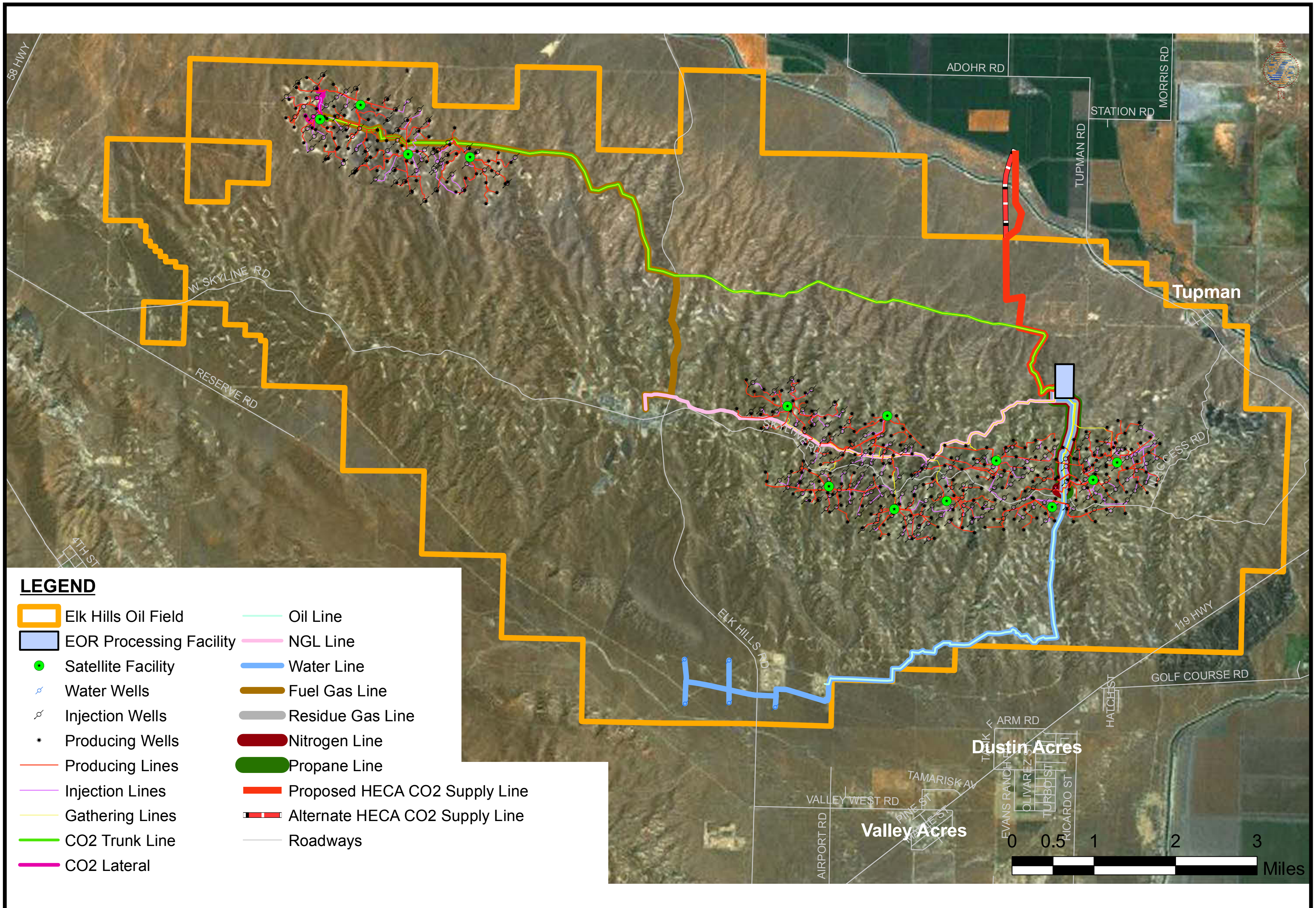


SOIL AND SURFACE WATER RESOURCES

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: HECA, 2012

SOIL AND SURFACE WATER RESOURCES - FIGURE 6

Hydrogen Energy California (HECA) - CO_2 - EOR Project Site



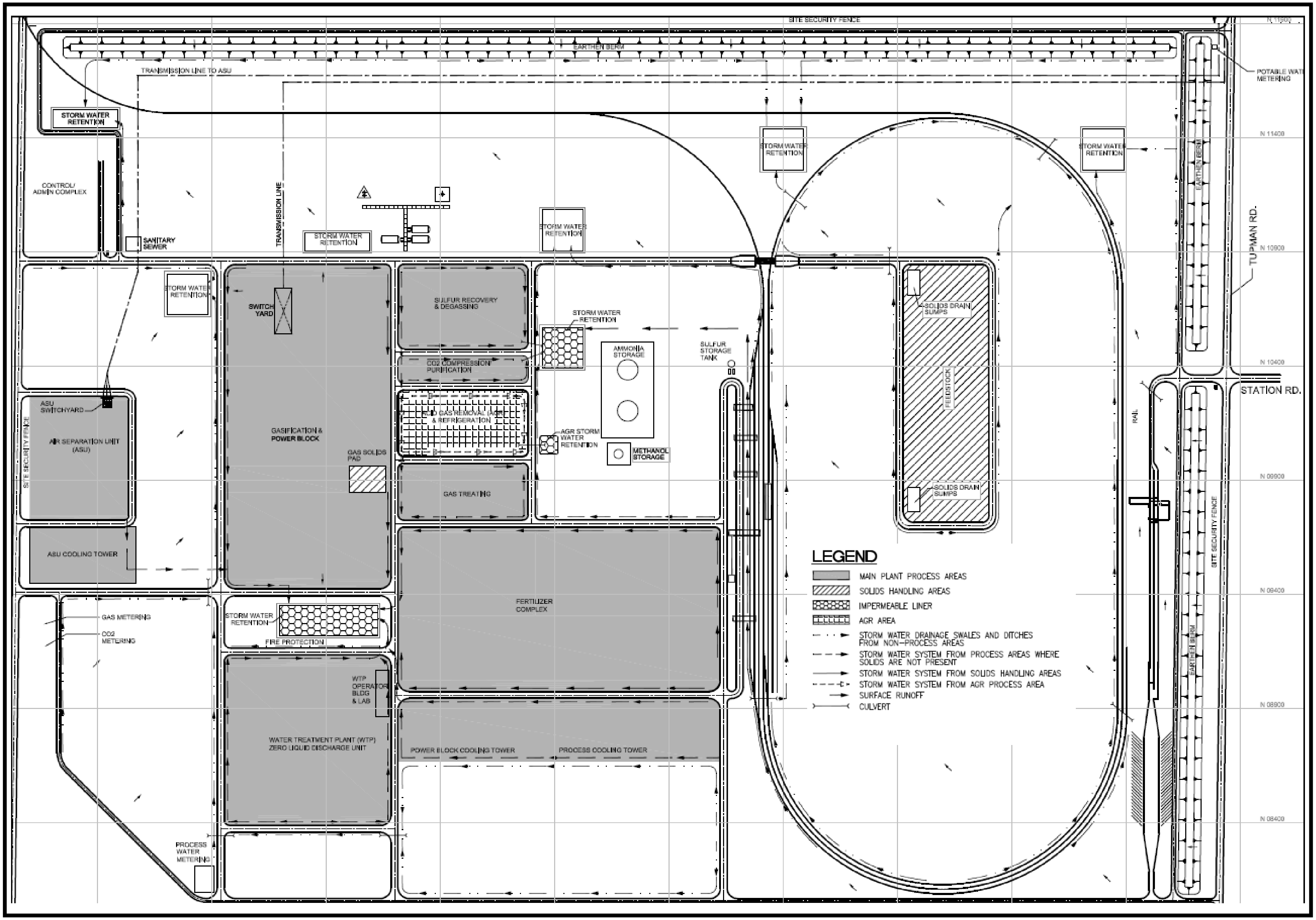
SOIL AND SURFACE WATER RESOURCES

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: Santec, 2012

SOIL AND SURFACE WATER RESOURCES - FIGURE 7

Hydrogen Energy California (HECA) - HECA Site Layout

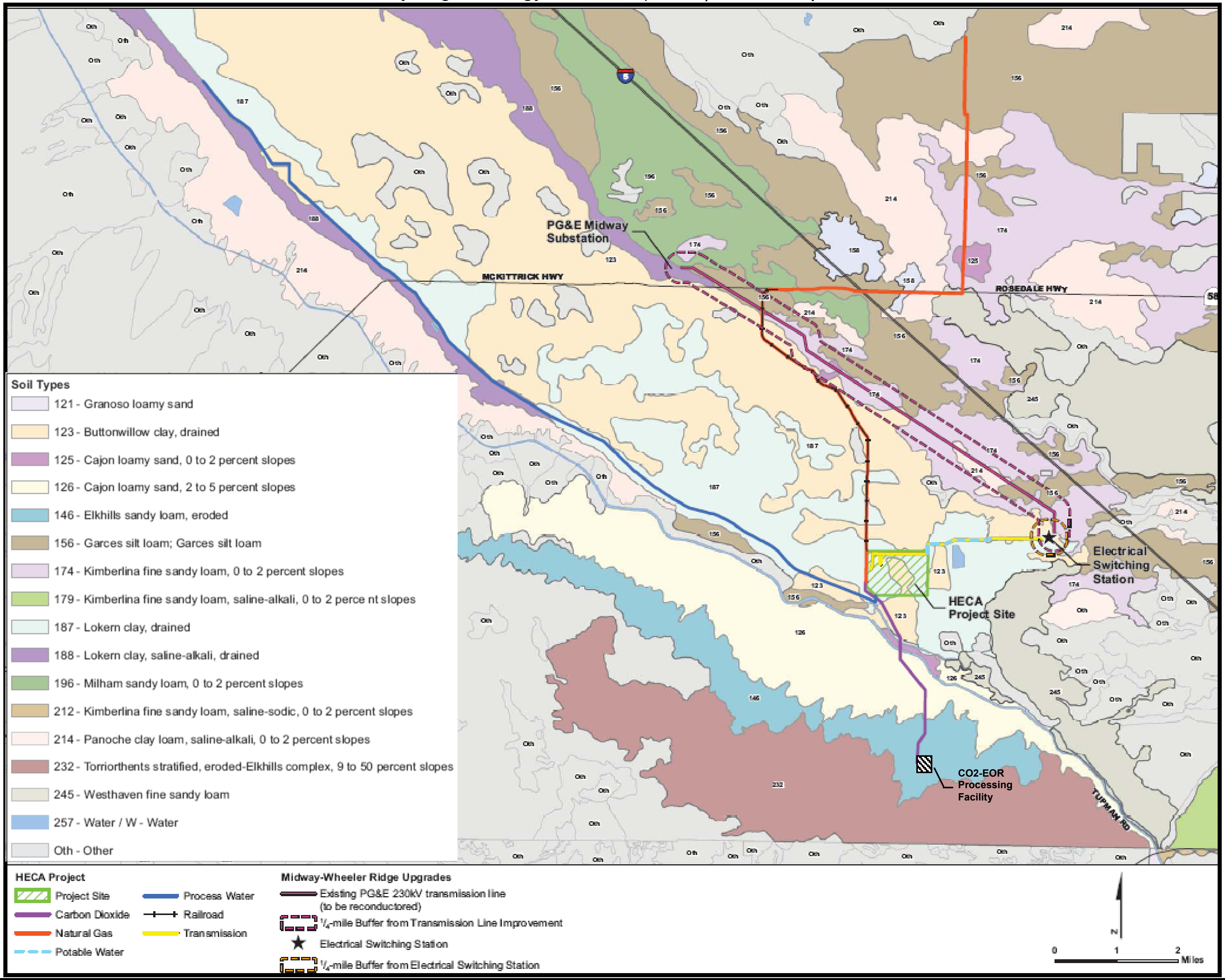


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: HECA, 2012

SOIL AND SURFACE WATER RESOURCES - FIGURE 8

Hydrogen Energy California (HECA) - Soil Map

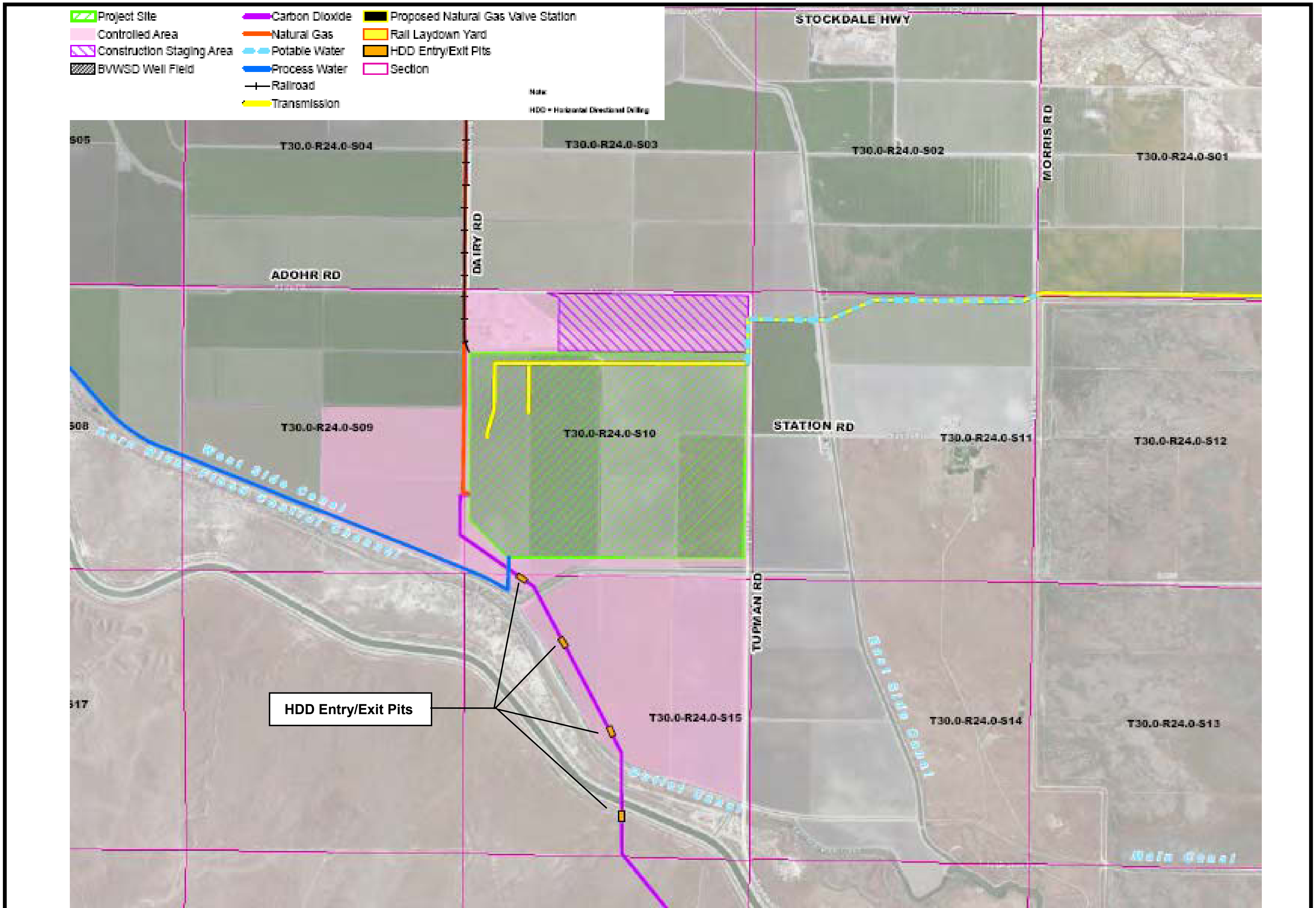


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: URS, 2013

SOIL AND SURFACE WATER RESOURCES - FIGURE 9

Hydrogen Energy California (HECA) - Locations of Horizontal Directional Drilling



SOURCE: HECA, 2012

TRAFFIC AND TRANSPORTATION

John Hope

SUMMARY OF CONCLUSIONS

Energy Commission staff has analyzed the information provided in the Application for Certification (AFC) and acquired from other sources to determine the potential for the Hydrogen Energy California (HECA) project to have significant adverse traffic and transportation-related impacts. Staff has also assessed the potential for mitigation proposed by the applicant and conditions developed by staff to reduce any potential impacts, as well as the feasibility and enforceability of those proposed mitigations and recommended conditions of certification.

As currently proposed, the HECA project could result in significant impacts to the traffic and transportation system serving the project site and surrounding community as follows:

- The HECA project could significantly degrade existing peak hour levels-of-service (LOS) at the intersections of SR 43/Stockdale Highway, SR 119/Tupman Road, Dairy Road/Adohr Road, and Dairy Road/Stockdale Highway resulting in increased delays for vehicles. However, Conditions of Certification **TRANS-1** and **TRANS-2** would reduce these impacts.
- The HECA project could substantially increase traffic on certain roadway segments resulting in potential degradation of roadway surfaces. However, Conditions of Certification **TRANS-3** and **TRANS-4** would reduce these impacts.
- High velocity thermal plumes emitted from the HECA project's exhaust stacks could present a potentially significant hazard to aircraft flying directly overhead at low altitude. However, Conditions of Certification **TRANS-7** through **TRANS-10** would reduce these potential impacts to a less than significant level.
- Although potentially significant impacts associated with implementation of the proposed HECA project can be mitigated to a less-than-significant level, staff has concerns that the project has the potential to substantially increase traffic levels on farming roads not currently intended for heavy truck traffic and heavy load capacities. This substantial increase in traffic also has the potential to impact traffic associated with existing farming activities (e.g., tractors traveling on public roadway) thereby potentially resulting in safety issues and increased accidents to the public. Based on a recent Board of Supervisor's meeting held on February 26, 2013, the Board instructed the Public Works Department to review the roadways intended for heavy truck, and worker traffic and report back at their June 2013 Board meeting as to recommendations for improvements to the local roadway system. Staff will address the concerns and/or recommendations by Kern County in the FSA.

It is noted that there are outstanding issues for the proposed project which are not able to be analyzed as part of this PSA/DEIS. These outstanding issues are discussed in the "Outstanding Information Required for Completion of the FSA/FEIS" section below. Staff is unable to reach a conclusion until outstanding information is provided.

INTRODUCTION

In compliance with California Environmental Quality Act (CEQA) and Energy Commission requirements, this analysis identifies the HECA project's potential impacts to the surrounding transportation systems and proposes mitigation measures (conditions of certification) that would avoid or lessen these impacts to a less-than-significant level. It also addresses the project's consistency with applicable federal, state, and local transportation-related laws, ordinances, regulations, and standards (LORS).

As discussed in the Introduction, this document analyzes the project's impacts pursuant to both the National Environmental Policy Act (NEPA) and CEQA. The two statutes are similar in their requirements concerning analysis of a project's impacts. Therefore, unless otherwise noted, staff's use of, and reference to, CEQA criteria and guidelines also encompasses and satisfies NEPA requirements for this environmental document.

SETTING

The 453-acre proposed HECA project site is comprised of parcels currently used for farming purposes. In addition, the applicant is also purchasing additional parcels adjacent to the project site totaling 633 acres for the purposes of public access control and future land uses. The HECA site is bounded by Adohr Road on the north, Tupman Road to the east, an irrigation canal to the south, and Dairy Road to the west. Primary access to the site would be from Station Road via Morris Road and Stockdale Highway. Stockdale Highway and Interstate 5 (I-5) are located approximately 1 mile to the north and 3 miles to the east, respectively. The Elk Hills-Buttonwillow Airport, which is a public airport primarily used for general aviation, is located approximately 5 miles northwest of the proposed project site. Elk Hills Oil Field is located approximately 1 mile south of the proposed HECA site. **Traffic and Transportation Figures 1-1** and **1-2** display the regional and local roadway system.

APPLICANT-PROPOSED IMPROVEMENTS AND TRAFFIC MEASURES

In the AFC for the HECA project, the applicant has proposed the following roadway improvements and traffic measures:

- The project owner will coordinate with Kern County to identify and construct roadway improvements, if needed, to support construction traffic to ensure that roadway impacts are less than significant.
- The project owner will coordinate with Kern County and Caltrans to identify and construct intersection improvements needed to support construction traffic so that intersection impacts are reduced to less-than-significant levels. The following intersections will require improvements:
    - Signalization of the current 4-way-stop SR 43 (Enos Lane)/Stockdale Highway intersection.
    - Signalization of the current 2-way-stop SR 119/Tupman Road intersection.

- At the Dairy Road/Stockdale Highway intersection, construct a separate left-turn lane on the westbound approach of Stockdale Highway, and construct a separate right-turn lane on the northbound approach of Dairy Road.
- At the Dairy Road/Adohr Road intersection, reconstruct the intersection to accommodate the turning radius needed by large trucks to make the turns.

- The project owner will use proper signs and traffic control measures in accordance with Caltrans and county requirements. All traffic signs, equipment, and control measures shall conform to the provisions specified in the Manual of Uniform Traffic Control Device (MUTCD), California Edition.
- The project owner will schedule potential traffic lane or road closures during off-peak hours whenever possible.
- The project owner will limit vehicular traffic to designated access roads, construction laydown and worker parking areas, and the project construction site.
- The project owner will implement Transportation Demand Management Measures (TDM) which encourage worker carpooling to minimize drive-alone worker trips. The project owner will provide incentives and develop a reward system to increase voluntary participation of various TDM measures.
- The project owner will limit vehicular traffic to designated access roads. The project owner will encourage worker carpooling to minimize drive-alone worker trips.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Traffic and Transportation Table 1 provides a general description of adopted federal, state, and local LORS pertaining to traffic and transportation relevant to the proposed project.

TRAFFIC and TRANSPORTATION Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	
Aeronautics and Space Title 14 Code of Federal Regulations (CFR), part 77 Objects Affecting Navigable Airspace (14 CFR 77)	Establishes standards for determining physical obstructions to navigable airspace; sets noticing and hearing requirements; and provides for aeronautical studies to determine the effect of physical obstructions on the safe and efficient use of airspace.
49 CFR, Subtitle B	Includes procedures and regulations pertaining to interstate and intrastate transport (including hazardous materials program procedures) and provides safety measures for motor carriers and motor vehicles that operate on public highways.
State	
California Vehicle Code, div. 1; div. 2, chapter 2.5; div. 6, chap. 2 & 7; div. 13, chap. 5; div. 14; div. 14.1, chap. 1 & 2; div. 14.3; div. 14.7; div. 14.8; div. 15	Includes regulations pertaining to licensing, size, weight, and load of vehicles operated on highways; safe operation of vehicles; and the transportation of hazardous materials.
California Streets and Highway Code, division 1 & 2, chapter 3 & chapter 5.5	Includes regulations for the care and protection of state and county highways and provisions for the issuance of written permits.
California Street and Highway Code §§117, 660-711	Requires permits from California Department of Transportation (Caltrans) for any roadway encroachment during truck transportation and delivery.
California Street and Highway Code §§660-711	Requires permits for any load that exceeds Caltrans weight, length, or width standards for public roadways.
California Manual on Uniform Control Devices (MUTDC) Chapter 6C	Describes temporary traffic control (TTC) measures to be used for facilitating road users through a work zone or an incident area. TTC plans play a vital role in providing continuity of reasonably safe and efficient road user flow when a work zone, incident, or other event temporarily disrupts normal road user flow.
CPUC Code Reference §§1001, 1007, 1008, 1904(a)	Requires an Application for Certificate of Public Convenience and Necessity (CPCN) to operate a rail facility.
CPUC General Order 22-B, 26-D, 33-B, 72-B, 75-D, 88-B, 95, 108, 110, 114, 118-A, 125, 126, 135, 145, 161	Safe operation of rail lines

Local	
Kern County Airport Land Use Compatibility Plan (ALUCP)	Requires local agencies to ensure compatible land uses in the vicinity of existing or proposed airports; to coordinate planning at state, regional, and local levels; to prepare and adopt an airport land use plan; to review plans, regulations, or locations of agencies and airport operators; and to review and make recommendations regarding the land uses, building heights, and other issues relating to air navigation safety and promotion of air commerce.
Kern County (ALUCP) Section 3.3.5	Prohibits land use characteristics that may produce hazards to aircraft in flight including sources of electrical interference with aircraft communications or navigation
Kern County General Plan Circulation Element	• Chapter 2 (Circulation Element), Goal 5, specifies that all county roadways shall operate at a Level of Service D or better; • Circulation Element Subsection 2.3.3 (Highway Plan), Goal 5, specifies that all county highways shall operate at a Level of Service D or better; and • Circulation Element, Policy 4, specifies that as a condition of private development approval, developers shall build roads needed to access the existing road network. Developers shall build these roads to County standards unless improvements along state routes are necessary then roads shall be built to California Department of Transportation standards. Developers shall locate these roads (width to be determined by the Circulation Plan) along centerlines shown on the circulation diagram map unless otherwise authorized by an approved Specific Plan Line. Developers may build local roads along lines other than those on the circulation diagram map. Developers would negotiate necessary easements to allow this requirement.
Kern County Regional Transportation Plan	Chapter 4 (Strategic Investments) of the Regional Transportation Plan (RTP) includes a listing of State highways and principal arterials within Kern County designated as part of the Congestion Management System, including level of service standards (Level of Service E or better) for these designated RTP roadways.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

Significance criteria used in this document for evaluating environmental impacts are based on the CEQA Guidelines, the CEQA Environmental Checklist for Transportation/Traffic, and applicable LORS used by other governmental agencies. These criteria also satisfy NEPA requirements for analyzing environmental impacts. Specifically, staff analyzed whether the proposed project would result in the following:

1. Cause an increase in traffic which is substantial in relation to the existing traffic load and capacity of the street system (i.e., result in a substantial increase in either the number of vehicle trips, the volume-to-capacity ratio on roads, or congestion at intersections);
2. Conflict with an applicable plan, ordinance or policy establishing measures of effectiveness for the performance of the circulation system, taking into account all modes of transportation including mass transit and non-motorized travel and relevant components of the circulation system, including but not limited to intersections, streets, highways and freeways, pedestrian and bicycle paths;
3. Conflict with an applicable congestion management program, including, but not limited to, level of service standards (LOS) and travel demand measures, or other standards established by the county congestion management agency for designated roads or highways;

4. Substantially increase hazards due to a design feature (e.g., sharp curves or dangerous intersections) or incompatible uses (e.g., farm equipment);
5. Result in inadequate emergency access;
6. Conflict with adopted policies, plans, or programs regarding public transit, bicycle, or pedestrian facilities, or otherwise decrease the performance or safety of such facilities;
7. Result in a change in air traffic patterns, including either an increase in traffic levels or a change in location that results in substantial safety risks;
8. Produce a thermal plume in an area where flight paths are expected to occur below 1,000 feet from the ground[1]; or
9. Have individual environmental effects which, when considered with other impacts from the same project or in conjunction with impacts from other closely related past, present, and reasonably foreseeable future projects, are considerable, compound, or increase other environmental impacts.

ASSESSMENT OF TRAFFIC IMPACTS

Setting

The following roadways are located near the proposed HECA project and may be impacted by construction and operations traffic.

Interstate 5 (I-5)

I-5, located approximately 4 miles east of the HECA site, is a major north-south regional transportation route through Kern County. Near the HECA site, I-5 provides two mainline lanes in each direction with wide shoulders and a center median, providing separate acceleration/deceleration lanes at the interchange of I-5/State Route 119, I-5/Stockdale Highway, and I-5/State Route 58. The speed limit of I-5 in the vicinity of the proposed HECA site is posted at 70 miles per hour (mph) for cars and 55 mph for trucks. The Annual Average Daily Traffic (AADT) on the segment of I-5 within the proposed project area is 31,000 vehicles per day, with truck traffic accounting for 25 percent of this volume (URS 2012a, pp. 5.10-5 - 5.10-6).

State Route 119 (SR 119)

SR 119 is an east-west state highway located approximately 7 miles south of the HECA site. SR 119 provides regional and emergency egress and workforce commute to the HECA site. SR 119 connects to State Route 99 (SR 99) on the east with State Route 33 (SR 33) on the west. Near the HECA site, SR 119 has a two-lane (one lane in each direction) cross section with an 8- to 12-foot shoulder on both sides with a posted speed limit of 55 mph. The ADT on the highway just west of I-5 southbound ramps is 10,000 vehicles per day, with truck traffic accounting for 20% of this volume. The proposed project does not plan to use SR 119 as the primary access route during construction and operation activities (URS 2012a, p. 5.10-6). The ADT on the segment of SR 119 east of Tupman Road is projected to be approximately 12,000 vehicles per day in 2016

[1] The FAA recommends that pilots avoid overflight of plume-generating industrial sites below 1,000 feet AGL (FAA 2006).

(URS 2012b, p. 159-2).

State Route 58 (SR 58)

SR 58, located approximately 4 miles north of the proposed HECA site, is an east-west state highway consisting of a two-lane conventional state highway with 4- to 8-foot shoulders and a posted speed limit of 55 mph in vicinity near the HECA site (HEI 2008c, p. 5.10-5). The I-5 southbound ramp/SR 58 interchange is currently signalized. The ADT on the segment of SR 58 west of SR 43 is 6,900 vehicles per day, with truck traffic accounting for 21% of this volume. SR 58 is designated as a state truck route (URS 2012a, p. 5.10-6).

State Route 43 (SR 43)

SR 43, located approximately 7 miles east of the proposed HECA site, is a north-south state highway. SR 43 is a two-lane road north of its intersection with Stockdale Highway. SR 43 becomes Central Valley Highway in the city of Shafter, California, and widens to a four-lane undivided highway. North of Shafter, SR 43 becomes a four-lane divided highway with a 65 mph speed limit. In Kern County, SR 43 is a designated Terminal Access Truck Route. The ADT on the segment of SR 43 north of Stockdale Highway is 9,000 vehicles per day, with truck traffic accounting for 21% of this volume (URS 2012a p. 5.10-6).

Stockdale Highway

Stockdale Highway is an east-west highway located one mile north of the HECA site. It starts near Wasco Way on the west and continues to the east through metropolitan Bakersfield, with an unsignalized freeway interchange providing connection to I-5. The segment of Stockdale Highway in the vicinity of the proposed HECA project has two through lanes (one lane in each direction) with no shoulders and a posted speed limit of 55 mph (URS 2012a, p. 5.10-6). The ADT on the segment of Stockdale Highway west of I-5 is projected to be approximately 2,000 vehicles per day in 2016 (URS 2012b, p. 159-2).

Adohr Road

Adohr Road is an east-west roadway containing two-lanes and is classified as Major (Arterial) Highway by the Kern County General Plan Circulation Element and would provide main access to the proposed HECA site (HEI 2008c, p. 5.10-7). This roadway starts at Freeborn Road on the west and ends at Tupman Road on the east and is relatively straight with flat terrain in the vicinity of the proposed HECA site (URS 2012a, p. 5.10-7). The ADT on the segment of Adohr Road east of Dairy Road is projected to be approximately 300 vehicles per day in 2016 (URS 2012b, p. 159-2).

Dairy Road

Dairy Road is a north-south local roadway containing two-lanes starting at Adohr Road on the south and ends at Stockdale Highway on the north. The intersection of Stockdale Highway and Dairy Road is controlled by a stop sign on Dairy Road. The roadway segment is relatively straight and the terrain is flat in the vicinity of the proposed HECA site (URS 2012, p. 5.10-7). The ADT on the segment of Dairy Road south of Stockdale Highway is projected to be approximately 200 vehicles per day in 2016 (URS 2012b, p.

159-2).

Morris Road

Morris Road is a north-south local roadway containing two-lanes starting at Station Road on the south and ends at Stockdale Highway on the north. The intersection of Stockdale Highway and Morris Road is controlled by a stop sign on Morris Road. The roadway segment is relatively straight and the terrain is flat in the vicinity of the HECA site (URS 2012a, p. 5.10-7). The ADT on the segment of Morris Road south of Stockdale Highway is projected to be approximately 300 vehicles per day in 2016 (URS 2012b, p. 159-2).

Station Road

Station Road is an east-west local roadway containing two-lanes starting at Tupman Road on the west and ends at Morris Road on the east. The intersection of Tupman Road and Station Road is controlled by a stop sign on Station Road. The roadway segment is relatively straight and the terrain is flat in the vicinity of the proposed HECA site (URS 2012a, p. 5.10-67). The ADT on the segment of Station Road west of Morris Road is projected to be approximately 230 vehicles per day in 2016 (URS 2012b, p. 159-2).

Wasco Way

Wasco Way is a north-south local roadway containing two-lanes starting at Stockdale Highway on the south and ends at SR 58 on the north. The intersection of SR 58 and Wasco Way is controlled by a stop sign on Wasco Way. The roadway segment is relatively straight and the terrain is flat in the vicinity of the HECA site. The ADT on the segment of Wasco Way north of Stockdale Highway is projected to be approximately 1,900 vehicles per day in 2016 (URS 2012b, p. 159-2).

Tupman Road

Tupman Road is a north-south, two-lane primary road with 2-foot shoulders on both sides, and is classified as a collector road by the Kern County General Plan Circulation Element. Tupman Road is adjacent to the eastern boundary of the HECA site. The intersection of Tupman Road and SR 119 is unsignalized, with stop signs on Tupman Road. Heading north from SR 119, terrain along Tupman Road is relatively flat to moderately rolling grade, with some segments having limited horizontal sight visibility to opposing traffic. The posted speed limit is 55 mph in the vicinity of the proposed HECA site (URS 2012a, p. 5.10-7). The ADT on the segment of Tupman Road south of Adohr Road is projected to be approximately 130 vehicles per day in 2016 (URS 2012b, p. 159-2).

9th Street

9th Street is an east-west street in Wasco, California, extending from H Street to J Street on the north side of Wasco Coal Terminal. 9th Street has two lanes and is 55 feet wide with parking allowed on both sides of the street. The roadway segment is relatively straight, and the terrain is flat with good sight distance in both directions (URS 2012a, p. 5.10-7). The ADT on the segment of 9th Street east of H Street is projected to be approximately 350 vehicles per day in 2017 (URS 2012b, p. 159-3).

H Street

H Street is a north-south street in Wasco, California, extending north from J Street on the west side of Wasco Coal Terminal. H Street has two lanes and is 55 feet wide with parking allowed on both sides of the street. The roadway segment is relatively straight, and the terrain is flat with good sight distance in both directions (URS 2012a, p. 5.10-7). The ADT on the segment of H Street south of 9th Street is projected to be approximately 1,100 vehicles per day in 2017 (URS 2012b, p. 159-3).

J Street

J Street is a north-south street in Wasco, California, extending from Poso Avenue on the east side of Wasco Coal Terminal. J Street has four lanes and is 56 feet wide with parking allowed on both sides of the street. The roadway segment is relatively straight, and the terrain is flat with good sight distance in both directions (URS 2012a, p. 5.10-7). The ADT on the segment of J Street north of Poso Avenue is projected to be approximately 2,100 vehicles per day in 2017 (URS 2012b, p. 159-3).

Wasco Avenue

Wasco Avenue is a north-south street in Wasco, California, extending from Poso Avenue to Kimberlina Road on the east side of Wasco Coal Terminal. North of Poso Avenue, Wasco Avenue turns and becomes J Street. The roadway segment is relatively straight, and the terrain is flat with good sight distance in both directions (URS 2012a, pp. 5.10-7,-8). The ADT on the segment of Wasco Avenue north of Poso Avenue is projected to be approximately 1,500 vehicles per day in 2017 (URS 2012b, p. 159-3).

Poso Avenue

Poso Avenue is an east-west street in Wasco, California. Poso Avenue intersects SR 43 at an all-way stop-controlled intersection. Between SR 43 and Wasco Avenue there is an at-grade rail crossing with gates and flashing lights. The roadway segment is relatively straight, and the terrain is flat with good sight distance in both directions (URS 2012a, p. 5.10-8). The ADT on the segment of Poso Avenue east of SR 43 is projected to be approximately 2,800 vehicles per day in 2017 (URS 2012b, p. 159-3).

Kimberlina Road

Kimberlina Road is an east-west street in Wasco, California. Kimberlina Road intersects SR 43 at a signalized intersection. The roadway segment is relatively straight, and the terrain is flat with good sight distance in both directions. The ADT on the segment of Kimberlina Road east of SR 43 is projected to be approximately 3,900 vehicles per day in 2017 (URS 2012b, p. 159-3).

Level of Service and Study Locations

Level of Service (LOS)

Level of Service (LOS) is a generally accepted measure used by traffic engineers and planners to describe and quantify the traffic congestion level on a particular roadway or intersection in terms of speed, travel time, and delay. The *Highway Capacity Manual*

2000[2], published by the Transportation Research Board Committee on Highway Capacity and Quality of Service, includes six levels of service for roadways and intersections. These levels of service range from LOS A, the best and smoothest operating conditions, to LOS F, the worst, most congested operating conditions.

The following locations on the surrounding roadway network were reviewed:

Freeways and Roadways:

- Interstate 5 (I-5) (north and south of Stockdale Highway)
- State Route 43 (SR 43) (north of Stockdale Highway, north of SR 58, south of 7th Standard, south of Lerdo Highway, south of Poso Avenue)
- State Route 119 (SR 119) (east of Tupman Road)
- Stockdale Highway (west of Dairy Road, west and east of I-5)
- Dairy Road (south of Stockdale Highway)
- Adohr Road (east of Dairy Road)
- Station Road (west of Morris Road)
- Morris Road (south of Stockdale Highway)
- Wasco Way (north of Stockdale Highway)
- Tupman Road (south of Adohr Road, north of SR 119)
- Wasco Avenue (south of Poso Avenue)
- J Street (north of Poso Avenue, south of 9th Street)
- H Street (south of 9th Street)
- Kimberlina Road (east of SR 43)
- Poso Avenue (east of SR 43)
- 9th Street (East of H Street)

Intersections:

- I-5 NB Ramp / Stockdale Highway
- I-5 SB Ramp / Stockdale Highway
- I-5 NB Ramp / SR 119
- I-5 SB Ramp / SR 119
- SR 119 / SR 43
- SR 43 / Stockdale Highway
- Stockdale Highway / Morris Road

[2] The *Highway Capacity Manual* (HCM) is the most widely used resource for traffic analysis. The Highway Capacity Manual is prepared by the Transportation Research Board, Committee on Highway Capacity and Quality of Service. The current edition was published in 2010.

- SR 119 / Tupman Road
- Tupman Road / Grace Avenue
- Tupman Road / Station Road
- Dairy Road / Stockdale Highway
- Dairy Road / Adohr Road
- SR 43 / Poso Avenue
- SR 43 / Kimberlina Road
- SR 43 / Shafter Avenue
- SR 43 / Central Avenue
- SR 43 / Lerdo Highway
- SR 43 / 7th Standard Road
- SR 43 / SR 58 (Rosedale Highway West)
- SR 43 / SR 58 (Rosedale Highway East)
- SR 58 / Wasco Way
- H Street / 9th Street
- H Street / Wasco Avenue
- Wasco Avenue / Poso Avenue
- Wasco Avenue / Kimberlina Road
- J Street / 9th Street

Level of service (LOS), volume-to-capacity (V/C), and delay standards for the various roadways and intersections in the vicinity of the HECA project are established by and under the jurisdiction of several different agencies. Staff used these standards to evaluate potential HECA-generated traffic impacts. The following is a list of the applicable standards:

- <u>Kern County - Kern County General Plan Circulation Element</u>

  The acceptable LOS standard for county roadways is LOS D or better.

- <u>California Department of Transportation (Caltrans) – Guide for the Preparation of Traffic Impact Studies (2002)</u>

  Caltrans endeavors to maintain a target LOS at the transition between LOS C and LOS D on state highway facilities. If an existing state highway facility is operating at less than the appropriate target LOS, the existing measures of effectiveness (MOE) should be maintained.

Peak Hour

Peak hour is defined as the part of a day during which traffic congestion on roads and crowding on public transport is at its highest. Typically this occurs twice per day – one time in the morning and one time in the evening – during times when the majority of people commute.

To determine the AM peak hour and PM peak hour for the proposed HECA project, traffic counts are taken for two hours between 7:00 and 9:00 AM and two hours between 4:00 and 6:00 PM. Traffic counts conducted during the 2-hour periods are then reviewed to identify the hour when the most vehicles are counted, or the hour of highest traffic (e.g., 7:15 to 8:15 AM). The number of vehicles counted during an identified peak hour is then used in the analysis of potential traffic impacts.

DIRECT/INDIRECT IMPACTS AND MITIGATION

The direct and indirect impacts of the proposed HECA project on the traffic and transportation system are discussed in this section and based on an analysis comparing pre-HECA and post-HECA conditions. Staff evaluated the HECA project's impacts for two separate future scenarios: peak construction period (when construction activity and employment would be maximized) and first year of full operation.

Traffic during the decommissioning period would likely be similar to traffic volumes experienced during construction, depending on the duration and extent of decommissioning, including dismantling of facilities and/or site remediation.

Construction Traffic

Analysis of HECA project construction impacts focuses on the peak construction period, which would generate the most vehicle trips and result in the worst-case scenario for traffic impacts.

Worker Traffic

As stated in AFC Section 2.0 (Project Description), the applicant expects that construction of the proposed HECA project would last approximately four years, starting in September/October 2013 and ending in September 2017. Peak construction trips were used to determine potential impacts as this would represent the worst-case construction traffic scenario. There would be a peak daily workforce of 2,460. The traffic analysis assumed that some workers would carpool and assumed one-third of the worker vehicles would arrive during the morning peak hour of 7:00 AM to 9:00 AM, and all would depart during the evening peak hour of 4:00 PM to 6:00 PM (URS 2012a, p. 5.10-30).

Construction equipment and material delivery projections indicate that during the peak construction month there would be 50 truck deliveries daily, a total equal to 100 daily one-way truck trips per day. These trips were subsequently converted into passenger car equivalent (PCE) trips at 3 PCE per truck (or 300 PCE trips). Even though truck deliveries would likely arrive and depart throughout the day, to represent the worst-case scenario the truck trips were conservatively assumed to occur during the morning peak hour. Additionally, the analysis assumed that there would be minimal deliveries during the evening peak hour (e.g., deliveries of time-critical equipment and materials, specialty loads).

During construction, soil fill materials would be imported to the HECA project site. The soil fill material deliveries were assumed to originate from local sources. Soil fill projections indicate that during the peak construction month there would be on average 160 truck deliveries daily, or 320 one-way daily truck trips per day. These trips were subsequently converted into PCE trips at 3 PCE per truck (or 960 trips). For purposes of this analysis, both the construction vehicle delivery and worker trips were converted to PCE trips, consistent with Caltrans *Highway Capacity Manual* guidelines. PCE is defined as the number of passenger cars that are displaced by a single heavy vehicle of a particular type under the prevailing traffic conditions. For example, a PCE of 2.0 indicates that two passenger vehicles are displaced by one heavy vehicle in the same traffic conditions. Heavy vehicles have a greater impact on traffic than passenger cars for the following reasons:

- Heavy vehicles are larger than passenger cars thereby occupying more space; and
- Heavy vehicle's performance characteristics are generally inferior to passenger cars which lead to the formation of downstream gaps in the traffic stream, especially on grades, which cannot always be effectively filled by normal passing maneuvers.

Based on the lack of elevation changes in the project vicinity and the physical size of heavy trucks anticipated to be used during construction of the proposed project, the applicant applied a PCE of 3.0 to each truck trip as part of this analysis. PCE 3.0 indicates that it is anticipated that one heavy vehicle associated with the project would displace three passenger vehicles in the same traffic conditions.

Traffic and Transportation Table 2 lists the estimate of total construction vehicle trips for the proposed HECA project in PCE, identifying which of those would be generated during both the AM and PM peak hour periods.

Traffic and Transportation Table 2
Estimated Average and Peak Hour Trip Generation – Peak Construction Period

	Actual Vehicle Round Trips	Peak Daily Trips	AM Peak Hour			PM Peak Hour		
			In	Out	Total	In	Out	Total
Construction Worker Vehicles[1]	1,230	2,460	410	0	410	0	1,230	1,230
Truck Deliveries[2]	50	300	75	75	150	0	0	0
Soil Fill Deliveries[3]	160	960	48	48	96	0	0	0

Source: URS 2012a, p.5.10-30

Notes:

1. Note that 2.0 passenger occupancy per vehicle was assumed to account for the carpooling of approximately 2,461 workers conservatively analyzed during the peak construction month, yielding 1,230 vehicles for the construction workers. It was conservatively assumed that one-third of the worker vehicles will arrive during the a.m. (peak one hour between 7:00 to 9:00 a.m.) and all will leave during p.m. (peak one hour between 4:00 to 6:00 p.m.) peak hours.
2. Trucks deliveries shown in the table were adjusted into Passenger Car Equivalent (3 PCE) vehicles. The trip generation estimate was based on the average 24-hour and maximum 1-hour truck delivery trips during Project construction. There are 50 (average 24-hour) truck deliveries @ 3 PCE/truck = 150 PCE vehicles. Peak daily trips (including both the inbound and outbound trips) = 2 × 150 PCE vehicles = 300 PCE Trips. There are 25 (maximum 1-hour) truck deliveries @ 3 PCE/truck = 75 PCE vehicles. Therefore, peak hourly trips (assuming equal number of inbound and outbound trips) = 2 × 75 PCE vehicles = 150 PCE Trips. It was further assumed that there will no Project deliveries during the p.m. peak hour.
3. Average import fill delivery truck trips (at 18-cubic-yard capacity per truck), adjusted into PCE vehicles (3 PCE per truck). The trip generation estimate was based on the average 24-hour and 1-hour trips during Project construction site preparation. There are 160 (average 24-hour) truck deliveries @ 3 PCE/truck = 480 PCE vehicles. Peak daily trips (including both the inbound and outbound trips) = 2 × 480 PCE vehicles = 960 PCE Trips. There are 16 (average 1-hour) truck deliveries @ 3 PCE/truck = 48 PCE vehicles. Therefore, peak hourly trips (assuming equal number of inbound and outbound trips) = 2 × 48 PCE vehicles = 96 PCE Trips. It must be noted that applying the maximum number of fill material truck loads is not appropriate, as these trips are anticipated to decrease and taper off on the later months of the Project construction schedule. For construction analysis purposes, using the average number of fill material truck loads is very conservative when added to the peak construction workforce as well as construction material delivery trips as these peak construction activities overlap.

Based on the construction vehicle trip calculations presented in **Traffic and Transportation Table 2**, an analysis was conducted in the AFC to determine the impacts of these construction vehicle trips on current study area intersections LOS. **Traffic and Transportation Table 3** identifies the current (2012) and future (2016) LOS anticipated with and without the proposed project construction vehicle traffic for critical intersections in the vicinity of the project. As described in **Traffic and Transportation Table 1,** Kern County does not have any LORS specifying acceptable LOS thresholds for intersections (General Plan Circulation Element LOS thresholds are specific to roadway segments). However, in maintaining consistency with the Kern County General Plan Circulation Element, staff utilized a LOS D threshold for determining intersection LOS impacts.

As shown in **Traffic and Transportation Table 3**, with the addition of the HECA project's peak construction traffic, all study area intersections will continue to operate at an acceptable LOS during the AM peak hour as compared to the future Year 2016 without project conditions. During the PM peak hour, the HECA project's peak construction traffic will temporarily impact both the SR 43/Stockdale Highway and SR 119/Tupman Road intersections, which are projected to degrade to LOS F.

It should be noted that 2016 With Project conditions, shown in **Traffic and Transportation Table 3**, include implementation of roadway improvements by the applicant (e.g., signalization of the current 4-way-stop SR 43 (Enos Lane)/Stockdale

Highway intersection; signalization of the current 2-way-stop SR 119/Tupman Road intersection; construct a separate left-turn lane on the westbound approach of Stockdale Highway and construct a separate right-turn lane on the northbound approach of Dairy Road at the Dairy Road/Stockdale Highway intersection; reconstruct the Dairy Road/Adohr Road intersection to accommodate the turning radius needed by large trucks to make the turn).

Traffic and Transportation Table 3
Current and Anticipated Year 2016 With and Without Project Intersection LOS - Construction

Intersection[1]	AM						PM					
	Current (2012)		2016 Without Project		2016 With Project		Current (2012)		2016 Without Project		2016 With Project	
	Delay	LOS	Delay	LOS	Delay	LOS	Delay	LOS	Delay	LOS	Delay	LOS
I-5 NB Ramp / Stockdale Highway	8.8	A	8.9	A	11.5	B	11.5	B	12.0	B	15.8	C
I-5 SB Ramp / Stockdale Highway	9.2	A	9.3	A	10.8	B	13.2	B	14.3	B	32.4	D
I-5 NB Ramp / SR 119	11.2	A	11.6	B	21.6	C	17.7	C	19.7	C	30.8	D
I-5 SB Ramp / SR 119	12.0	A	12.5	B	14.0	B	18.0	C	20.4	C	34.7	D
SR 119 / SR 43	25.3	C	26.2	C	27.6	C	23.0	C	24.2	C	27.3	C
SR 43 / Stockdale Highway	11.3	B	12.5	B	15.9	C	22.8	C	**36.4**	**E**	**142.2**	**F**
Stockdale Highway / Morris Road	8.8	A	8.8	A	10.7	B	9.3	A	9.5	A	13.5	B
SR 119 / Tupman Road	19.3	C	21.9	C	25.4	D	**65.4**	**F**	**105.0**	**F**	**OVRFL**	**F**
Tupman Road / Grace Ave.	7.0	A	7.0	A	7.9	A	7.0	A	7.0	A	11.6	B
Tupman Road / Station Road	8.6	A	8.7	A	9.4	A	8.6	A	8.6	A	14.5	B
Dairy Road / Stockdale Highway	8.7	A	8.7	A	11.6	B	10.4	B	9.8	A	28.2	D
Dairy Road / Adohr Road	9.0	A	9.0	A	16.2	C	8.8	A	8.9	A	14.1	B
SR 43 / Poso Avenue	10.6	B	11.2	B	11.4	B	11.5	B	12.4	B	13.0	B
SR 43 / Kimberlina Road	23.8	C	24.1	C	24.0	C	20.9	C	21.2	C	20.8	C
SR 43 / Shafter Avenue	12.8	B	12.9	B	12.8	B	12.8	B	13.2	B	13.2	B
SR 43 / Central Avenue	9.0	A	9.1	A	9.1	A	10.4	B	10.5	B	10.4	B
SR 43 / Lerdo Highway	22.1	C	22.3	C	22.2	C	21.6	C	21.8	C	22.1	C
SR 43 / 7th Standard Road	11.5	B	12.4	B	12.6	B	19.9	C	27.5	D	33.0	D
SR 43 / SR 58 (Rosedale Highway West)	10.6	B	11.3	B	11.7	B	13.6	B	15.4	C	21.8	C
SR 43 / SR 58 (Rosedale Highway East)	10.7	B	11.3	B	11.7	B	14.7	B	17.2	C	32.2	D
H Street / 9th Street	8.5	A	8.6	A	8.6	A	8.7	A	8.7	A	8.7	A
H Street / Wasco Avenue	8.7	A	8.7	A	8.7	A	8.9	A	9.0	A	9.0	A
Wasco Avenue / Poso Avenue	10.2	B	10.4	B	10.4	B	10.6	B	10.8	B	10.8	B
Wasco Avenue / Kimberlina Road	10.2	B	10.5	B	10.5	B	10.2	B	10.4	B	10.4	B
J Street / 9th Street	8.5	A	8.5	A	8.5	A	8.6	A	8.6	A	8.6	A
SR 58 / Wasco Way	-	-	14.6	B	20.2	C	-	-	14.4	B	17.7	C

Source: URS 2012a, pp. 5.10-34 and 35
[1] For existing intersection control features refer to **Traffic and Transportation Table 2**
*Degradation over the existing LOS to unacceptable level.
Bold text indicates unacceptable operating conditions
OVRFL indicates calculation exceeds the limits of the software program

Based on the construction vehicle trip calculations presented in **Traffic and Transportation Table 2**, an analysis was also conducted to determine the impacts of these construction vehicle trips on current traffic volumes on roadway segments in the study area. **Traffic and Transportation Table 4** identifies the baseline (2016) and future traffic volumes anticipated with the proposed project construction vehicle traffic for roadway segments in the vicinity of the project. As described in **Traffic and Transportation Table 1,** Kern County has LORS specifying LOS D as the acceptable LOS thresholds for roadway segments.

As shown in **Traffic and Transportation Table 4**, with the addition of the HECA project's peak construction traffic, all study area roadway segments will continue to operate at an acceptable LOS as compared to future Year 2016 without project conditions. Although all study area roadways will continue to operate at an acceptable LOS, implementation of the proposed project would substantially increase traffic on certain roadway segments as compared to future Year 2016 without project conditions. Specifically, some roadway segments would experience a substantial increase in the AADT such as Dairy Road (1,262% increase), Adohr Road (438% increase), and Tupman Road (902% and 133% increases). It should be noted that trips added to Wasco Way, north of Stockton Highway, are attributed to an alternative traffic route for construction workers traveling from the HECA site during the PM peak hour (HECA, pers. comm., 2013).

Traffic and Transportation Table 4
Current and Anticipated Year 2016 With and Without Project Roadway Segment AADT Levels of Service – Construction

Roadway Segment	Baseline AADT (2016)	LOS	Project Added AADT	Baseline Plus Project AADT	LOS	Increase in AADT (%)
Interstate 5						
North of Stockdale Highway	36,960	A	482	37,442	A	1%
South of Stockdale Highway	34,720	A	396	35,116	A	1%
State Route 43						
North of Stockdale Highway	6,160	A	115	6,275	A	2%
State Route 119						
East of Tupman Road	11,872	C	738	12,610	D	6%
Stockdale Highway						
West of Dairy Road	1,804	A	1,576	3,380	A	**87%**
West of I-5	2,009	A	1,162	3,171	A	**58%**
East of I-5	4,579	A	632	5,211	A	14%
Dairy Road						
South of Stockdale Highway	202	A	2,550	2,752	A	**1,262%**
Adohr Road						
East of Dairy Road	291	A	1,276	1,567	A	**438%**
Station Road						
West of Morris Road	227	A	188	415	A	**83%**
Morris Road						
South of Stockdale Highway	281	A	188	469	A	**67%**
Wasco Way						
North of Stockdale Highway	1,858	A	616	2,474	A	33%
Tupman Road						
South of Adohr Road	130	A	1,172	1,302	A	**902%**
North of SR 119	648	A	862	1,510	A	**133%**

Source: URS 2012b, p. 159-1 – 159-3,160-1 – 160-4
Bold text indicates substantial increase in number of vehicle trips (50% increase or greater)

To minimize impacts from construction related trips, staff is proposing Condition of Certification **TRANS-1,** which would require the project owner to prepare a Construction Traffic Control Plan prior to site mobilization in order to reduce the significance of construction traffic. Even with the implementation of Condition of Certification **TRANS-1,** construction related traffic impacts would remain significant at both the SR 43/Stockdale Highway and SR 119/Tupman Road intersections due to construction related traffic temporarily reducing these intersections to LOS F conditions during the PM peak hour.

As stated previously, construction activities associated with the project would substantially increase the number of trips on certain roadways segments and would equally increase trips through specific intersections including Tupman Road/SR 119, Morris Road/Stockdale Highway, Dairy Road/Stockdale Highway, Dairy Road/Adohr Road, and Station Road/Tupman Road. These intersections are currently stop controlled in only one direction (through traffic is unimpeded while adjoining traffic is required to stop). Uncontrolled intersections are known sources of accidents because these intersections incur the majority of risk to travelers. Therefore, the increase in construction truck traffic with implementation of the proposed project would subsequently increase risk to travelers and the potential for accidents.

As indicated in the AFC and also stated earlier in this analysis, the applicant is proposing improvements to four intersections (i.e., SR 43/Stockdale Highway, SR 119/Tupman Road, Dairy Road/Adohr Road, Dairy Road/Stockdale Highway) to reduce LOS impacts (URS 2012, p. 5.10-13). Staff recommends improvements at two additional intersections (i.e., Morris Road/Stockdale Highway, Station Road/Tupman Road) to reduce the potential for accidents. To ensure these improvements are made, Condition of Certification **TRANS-2** is proposed and will require physical improvements at these intersections to reduce impacts from construction-related trips.

Linear Facilities

In addition to direct construction related trips, interconnecting the HECA project into the Pacific Gas and Electric (PG&E) system will require the construction of approximately 8 miles of transmission line. Intersections and roadway segments along the transmission line routes may be temporarily affected during construction. However, traffic impacts at roadways during utility infrastructure stringing activities would be site-specific and temporary in duration.

Project linear facilities include 8 miles of electrical transmission line, 8 miles of natural gas supply pipeline, 7 miles of potable water supply pipeline, and 4 miles of carbon dioxide pipeline. These linear facilities have the potential to result in temporary lane closures during stringing and tunneling activities. Traffic impacts from the construction of the linear facilities would be short term in nature, mitigated by cones and flagmen when necessary, and not expected to significantly impact traffic flow. Proposed Condition of Certification **TRANS-1** requires the Construction Traffic Control Plan (prepared in conjunction with Kern County and Caltrans) identify any temporary closure of travel lanes or disruptions to street segments and intersections and ensures access to residential and/or commercial property during transmission line stringing activities or any other utility tie ins. This condition will mitigate any significant adverse impact on traffic flows on the local roadway system during construction of the linear facilities.

Rail

The applicant is proposing to construct a 5-mile long rail spur as one alternative option for delivering coal to the facility. This rail spur would traverse south from SR 58 (between Brandt Road and Tracy Lane) to the East Side Canal, then parallel the East Side Canal to Dairy Road, and then parallel Dairy Road to the project site. Construction of the rail spur would generate additional construction-related trips. Intersections and roadway segments along the new rail line route may be temporarily affected during construction. However, traffic impacts at roadways during rail line construction activities would be site-specific and temporary in duration.

The rail line has the potential to result in temporary lane closures during construction activities. Traffic impacts from construction of the rail line would be short term in nature, mitigated by cones and flagmen when necessary, and not expected to significantly impact traffic flow along Stockdale Highway and Adohr Road. Proposed Condition of Certification **TRANS-1** requires that the Construction Traffic Control Plan (prepared in conjunction with Kern County and Caltrans) identifies any temporary closure of travel lanes or disruptions to street segments and intersections and requires the project owner to ensure access to residential and/or commercial property during rail line construction activities. This condition will mitigate any significant adverse impact on traffic flows on the local roadway system during construction of the rail line.

Bridge Capacities

Construction of the proposed project would involve transportation of heavy project components, such as turbines, from the Port of Stockton via heavy trucks. Dependent upon the route(s) trucks carrying heavy project components take, the trucks could require crossing a bridge. The applicant engaged a heavy haul contractor to evaluate the truck route from the Port of Stockton to the project site. The evaluation concluded that all bridges along the truck route have the capability to support the estimated heavy haul loads (HECA, pers. comm., 2013).

Enhanced Oil Recovery (EOR)

The OEHI CO_2 EOR Project (OEHI) would generate new vehicle trips during construction and operational phases that would occur over a 20-year timeframe. The majority of personnel required during construction would be employees currently involved with existing facility operations with additional personnel comprising of local contractors. The annual average vehicle trips estimated during construction are shown in **Traffic and Transportation Table 5**. As shown in **Traffic and Transportation Table 5**, the amount of construction worker vehicle trips would be higher during earlier years of construction then would decline over the remaining years.

Traffic and Transportation Table 5
Construction Annual Average Daily Trips

Year	Construction AADT (one way)	Year	Construction AADT (one way)
2014	140	2024	48
2015	241	2025	56
2016	25	2026	3
2017	149	2027	27
2018	161	2028	64
2019	243	2029	22
2020	21	2030	3
2021	27	2031	21
2022	2	2032	3
2023	6	2033	19

Source: URS 2012, Appendix A-1, pp. 4.15-17

As shown in **Traffic and Transportation Table 6**, with the addition of the OEHI project's traffic, five intersections in the project area are projected to degrade to LOS E by the year 2030.

Traffic and Transportation Table 6
Existing and Projected Year 2030 with Project Intersection LOS

Intersection	2004 or 2006		2015		2030	
	Peak Hour	LOS	Peak Hour	LOS	Peak Hour	LOS
SR 119 / North Access Road	1,050	D	1,400	**E**	1,800	**E**
SR 119 / Tupman Road	1,150	D	1,400	D	2,000	**E**
SR 119 / Elk Hills Road	1,050	D	1,400	D	1,900	**E**
SR 58 / Wasco Way	1,110	D	1,630	D	2,390	**E**
SR 33/58 / 'E' Street	330	C	430	C	560	D
SR 43 / SR 119	1,150	D	1,500	D	2,000	**E**

Source: URS 2012, Appendix A-1, pp. 4.15-13
Bold text indicates unacceptable operating conditions

Caltrans proposes improvements to SR 119 in the OEHI project area, including intersections potentially impacted by construction-related activities of the OEHI project. Improvements would include widening SR 119 from a two-lane highway to a four-lane expressway. These improvements to SR 119 are planned to be completed by the year 2025 (Caltrans 2006, pp. 12).

Kern County is the licensing authority for the OEHI project. Therefore, to minimize impacts from EOR construction related trips, staff recommends Kern County adopt mitigation like what is proposed in Condition of Certification **TRANS-1,** which would require implementation of a Construction Traffic Control Plan to reduce the significance of construction traffic impacts associated with the HECA project.

Operational Impacts and Mitigation

Once operational, the proposed HECA project would require a fulltime employee workforce to oversee project operations and maintenance (O&M). Anticipated HECA project operational traffic would be associated primarily with operation worker commute trips, feedstock deliveries, process materials and products truck trips, and O&M trips

(URS 2012a, p. 5.10-11).

Two alternatives are under consideration for transporting coal to the HECA project site:

1) constructing a rail spur or;

2) using trucks to deliver coal after it has been transported by rail from New Mexico.

For the rail spur option (listed as Alternative 1 in the AFC), an approximately 5-mile-long new industrial railroad spur would be constructed to connect the HECA project site to the existing San Joaquin Valley Railroad (SJVRR) Buttonwillow railroad line. This railroad spur would also be used to transport some HECA products to market. For the no rail spur option (listed as Alternative 2 in the AFC), an approximately 27-mile-long truck transport route would be used via existing roads to transport the coal from an existing coal trans-loading facility located northeast of the HECA project site. The applicant is currently requesting that both options be certified.

Traffic and Transportation Table 7 lists the estimate of total peak daily operational related vehicle trip for both alternatives of the proposed HECA project, including identifying which of those trips would be generated during both the AM and PM peak hour periods.

Traffic and Transportation Table 7
Estimated Average and Peak Hour Trip Generation – Peak Daily Operation

	Actual Vehicle Round Trips	Peak Daily Trips	AM Peak Hour			PM Peak Hour		
			In	Out	Total	In	Out	Total
Truck Operation With Rail Spur								
Operations and Maintenance Trips	154	308	110	0	110	22	132	154
Process Materials and Byproducts Trips[1]	213	426	18	18	36	18	18	36
Feedstock Material Delivery Trips[2]	165	330	15	15	30	15	15	30
Truck Operation Without Rail Spur								
Operations and Maintenance Trips	154	308	110	0	110	22	132	154
Process Materials and Byproducts Trips[3]	399	798	36	36	72	36	36	72
Feedstock Material Delivery Trips[4]	900	1,800	60	60	120	15	15	30

Source: URS 2012a, p.5.10-31 and -32

Notes:

1 Total process materials and product truck trips, adjusted into Passenger Car Equivalent (PCE) vehicles (3 PCE per truck). The trip generation estimate is based on the maximum 24-hour and 1-hour trips during Project operation. There are 71 (maximum 24-hour) truck deliveries and shipments @ 3 PCE/truck = 213 PCE vehicles. Peak daily trips (including both the inbound and outbound trips) = 2 × 213 PCE vehicles = 426 PCE Trips. There are 6 (maximum 1-hr) truck deliveries and shipments @ 3 PCE/truck = 18 PCE vehicles. Therefore, peak hourly trips (assuming equal number of inbound and outbound trips) = 2 × 18 PCE vehicles = 36 PCE Trips.

2 Total feedstock material delivery truck trips (including petcoke and coal), adjusted into Passenger Car Equivalent vehicles (3 PCE per truck). The trip generation estimate is based on the maximum 24-hour and 1-hour trips during Project operation. There are 55 (maximum 24-hour) truck deliveries @ 3 PCE/truck = 165 PCE vehicles. Peak daily trips (including both the inbound and outbound trips) = 2 × 165 PCE vehicles = 330 PCE trips. There are 5 (maximum 1-hour) truck deliveries @ 3 PCE/truck = 15 PCE vehicles. Therefore, peak hourly trips (assuming equal number of inbound and outbound trips) = 2 × 15 PCE vehicles = 30 PCE trips. The feedstock trip assumption was based on the train delivery of coal and trucking of petcoke to the Project site.

3 Total process materials and products truck trips, adjusted into Passenger Car Equivalent (PCE) vehicles (3 PCE per truck). The trip generation estimate is based on the maximum 24-hour and 1-hour trips during Project operation. There are 133 (maximum 24-hour) truck deliveries and shipments @ 3 PCE/truck = 399 PCE vehicles. Peak daily trips (including both the inbound and outbound trips) = 2 × 399 PCE vehicles = 798 PCE trips. There are 12 (maximum 1-hour) truck deliveries and shipments @ 3 PCE/truck = 36 PCE vehicles. Therefore, peak hourly trips (assuming equal number of inbound and outbound trips) = 2 × 36 PCE vehicles = 72 PCE trips.

4 Total feedstock material delivery truck trips (including petcoke, and coal), adjusted into Passenger Car Equivalent vehicles (3 PCE per truck). The trip generation estimate is based on the maximum 24-hour and 1-hour trips during Project operation. There are 300 (maximum 24-hour) truck deliveries @ 3 PCE/truck = 900 PCE vehicles. Peak daily trips (including both the inbound and outbound trips) = 2 × 900 PCE vehicles = 1,800 PCE Trips. There are 20 (maximum 1-hour) truck deliveries @ 3 PCE/truck = 60 PCE vehicles. Therefore, peak hourly trips (assuming an equal number of inbound and outbound trips) = 2 × 60 PCE vehicles = 120 PCE trips. There will a break in coal trucking activities during the evening peak hour to minimize roadway conflicts with heavy vehicles; coal trucking activities will resume immediately after the peak evening traffic has dissipated.

Based on the construction vehicle trip calculations presented in **Traffic and Transportation Table 7**, an analysis was conducted in the AFC to determine the impacts of operational related vehicle trips on current and future baseline levels of service for study area intersections. **Traffic and Transportation Tables 8 and 9** identify the current and future (Year 2017) LOS anticipated with and without proposed project operational vehicle traffic added to critical intersections in the vicinity of the HECA site.

As shown in **Traffic and Transportation Tables 8 and 9**, operations-related traffic associated with the project would not impact or deteriorate any project area intersections to below an LOS D (as described above, a LOS D threshold is utilized to determine intersection impacts per the Kern County General Plan Circulation Element). As noted in **Traffic and Transportation Tables 8 and 9,** the operational related analysis assumes that intersection improvements required by Condition of Certification **TRANS-2** (required for construction impacts) would occur, and are considered a component of the existing street system in Year 2017 with project traffic conditions**.** Therefore, HECA project operations would have no additional impact on study area intersection LOS. Consequently, no operations-related mitigation measures are required.

Traffic and Transportation Table 8
Current and Anticipated Year 2017 With and Without Project Intersection Levels of Service
Train Operation

Intersection[1]	**AM**						**PM**					
	Current (2012)		**2017 Without Project**		**2017 With Project**		**Current (2012)**		**2017 Without Project**		**2017 With Project**	
	Delay	**LOS**	**Delay**	**LOS**	**Delay**	**LOS**	**Delay**	**LOS**	**Delay**	**LOS**	**Delay**	**LOS**
I-5 NB Ramp / Stockdale Highway	8.8	A	8.9	A	9.7	A	11.5	B	12.1	B	14.2	B
I-5 SB Ramp / Stockdale Highway	9.2	A	9.3	A	9.7	A	13.2	B	14.6	B	17.8	C
I-5 NB Ramp / SR 119	11.2	A	11.7	B	12.2	B	17.7	C	20.1	C	21.2	C
I-5 SB Ramp/ SR 119	12.0	A	12.6	B	13.0	B	18.0	C	21.0	C	22.5	C
SR 119 / SR 43	25.3	C	26.4	C	26.8	C	23.0	C	24.5	C	24.6	C
SR 43 / Stockdale Highway[2]	11.3	B	12.8	B	18.7	B	22.8	C	**40.9**	**E**	21.2	B
Stockdale Highway / Morris Road	8.8	A	8.8	A	9.7	A	9.3	A	9.5	A	10.2	B
SR 119 / Tupman Road[2]	19.3	C	22.5	C	2.9	A	**65.4**	**F**	**117.7**	**F**	9.4	A
Tupman Road / Grace Avenue	7.0	A	7.0	A	7.2	A	7.0	A	7.0	A	7.2	A
Tupman Road / Station Road	8.6	A	8.7	A	9.5	A	8.6	A	8.6	A	10.3	B
Dairy Road / Stockdale Highway	8.7	A	8.7	A	8.7	A	10.4	B	9.8	A	9.8	A
Dairy Road / Adohr Road	9.0	A	9.0	A	10.3	B	8.8	A	8.9	A	9.3	A

Source: URS 2012a, pp. 5.10-29, 36, and 37
[1] For existing intersection control features refer to **Traffic and Transportation Table 3**
[2] Assumed to be signalized in Year 2017 as part of Condition of Certification **TRANS-2**
Bold text indicates unacceptable operating conditions

Traffic and Transportation Table 9
Current and Anticipated Year 2017 With and Without Project Intersection Levels of Service
Truck Operation

Intersection[1]	AM						PM					
	Current (2012)		2017 Without Project		2017 With Project		Current (2012)		2017 Without Project		2017 With Project	
	Delay	LOS	Delay	LOS	Delay	LOS	Delay	LOS	Delay	LOS	Delay	LOS
I-5 NB Ramp / Stockdale Highway	8.8	A	8.9	A	10.5	B	11.5	B	12.1	B	18.2	C
I-5 SB Ramp / Stockdale Highway	9.2	A	9.3	A	10.6	B	13.2	B	14.6	B	27.7	D
I-5 NB Ramp / SR 119	11.2	A	11.7	B	12.3	B	17.7	C	20.1	C	22.4	C
I-5 SB Ramp / SR 119	12.0	A	12.6	B	13.0	B	18.0	C	21.0	C	24.1	C
SR 119 / SR 43	25.3	C	26.4	C	26.8	C	23.0	C	24.5	C	24.7	C
SR 43 / Stockdale Highway[2]	11.3	B	12.8	B	16.2	B	22.8	C	**40.9**	**E**	18.5	B
Stockdale Highway / Morris Road	8.8	A	8.8	A	10.9	B	9.3	A	9.5	A	11.4	B
SR 119 / Tupman Road[2]	19.3	C	22.5	C	2.0	A	**65.4**	**F**	**117.7**	**F**	7.5	A
Tupman Road / Grace Avenue	7.0	A	7.0	A	7.2	A	7.0	A	7.0	A	7.5	A
Tupman Road / Station Road	8.6	A	8.7	A	9.9	A	8.6	A	8.6	A	12.2	B
Dairy Road / Stockdale Highway	8.7	A	8.7	A	8.7	A	10.4	B	9.8	A	10.1	B
Dairy Road / Adohr Road	9.0	A	9.0	A	10.3	B	8.8	A	8.9	A	9.7	A
SR 43 / Poso Avenue	10.6	B	11.3	B	11.6	B	11.5	B	12.6	B	12.7	B
SR 43 / Kimberlina Road	23.8	C	24.1	C	24.2	C	20.9	C	21.2	C	21.1	C
SR 43 / Shafter Avenue	12.8	B	13.0	B	12.6	B	12.8	B	13.3	B	13.3	B
SR 43 / Central Avenue	9.0	A	9.1	A	8.7	A	10.4	B	10.5	B	10.5	B
SR 43 / Lerdo Highway	22.1	C	22.4	C	22.1	C	21.6	C	21.9	C	21.9	C
SR 43 / 7th Standard Road	11.5	B	12.6	B	14.2	B	19.9	C	29.7	D	31.0	D
SR 43 / SR 58 (Rosedale Highway West)	10.6	B	11.4	B	12.5	B	13.6	B	15.8	C	16.1	C
SR 43 / SR 58 (Rosedale Highway East)	10.7	B	11.5	B	12.6	B	14.7	B	17.9	C	18.2	C
H Street / 9th Street	8.5	A	8.6	A	8.7	A	8.7	A	8.8	A	8.8	A
H Street / Wasco Avenue	8.7	A	8.7	A	8.9	A	8.9	A	9.0	A	9.0	A
Wasco Avenue / Poso Avenue	10.2	B	10.4	B	11.5	B	10.6	B	10.9	B	10.9	B
Wasco Avenue / Kimberlina Road	10.2	B	10.5	B	10.3	B	10.2	B	10.5	B	10.5	B
J Street / 9th Street	8.5	A	8.5	A	8.7	A	8.6	A	8.6	A	8.6	A

Source: URS 2012a, pp. 5.10-29, 36, and 37
[1] For existing intersection control features refer to **Traffic and Transportation Table 3**
[2] Assumed to be signalized in Year 2017 as part of Condition of Certification **TRANS-2**
Bold text indicates unacceptable operating conditions

As shown in **Traffic and Transportation Tables 10 and 11**, with the addition of the HECA project's peak operation traffic, all study area roadway segments would continue to operate at an acceptable LOS as compared to future Year 2017 without project conditions. Although all study area roadways would continue to operate at an acceptable LOS, it should noted that implementation of the proposed project would substantially increase traffic on certain roadway segments as compared to future Year 2017 without project conditions. Specifically, some roadway segments would experience a substantial increase in the AADT such as Dairy Road (132% increase), Station Road (1,087% increase), and Morris Road (878% increase).

Traffic and Transportation Table 10
Current and Anticipated Year 2016 With and Without Project Roadway Segment AADT LOS – Operation – Alternate 1 (Rail Transportation)

Roadway Segment	Baseline AADT (2017)	LOS	Project Added AADT	Baseline Plus Project AADT	LOS	Increase in AADT (%)
Interstate 5						
North of Stockdale Highway	37,620	A	356	37,976	A	1%
South of Stockdale Highway	35,340	A	378	35,718	A	1%
State Route 43						
North of Stockdale Highway	6,270	A	16	6,286	A	0%
North of SR 58	10,260	B	16	10,276	B	0%
South of 7th Standard	5,700	A	16	5,716	A	0%
South of Lerdo Highway	11,400	C	16	11,416	C	0%
South of Poso Avenue	11,628	C	16	11,644	C	0%
State Route 119						
East of Tupman Road	12,084	D	92	12,176	D	1%
Stockdale Highway						
West of Dairy Road	1,837	A	0	1,837	A	0%
West of I-5	2,046	A	940	2,986	A	46%
East of I-5	4,664	A	208	4,872	A	4%
Dairy Road						
South of Stockdale Highway	205	A	258	463	A	**126%**
Adohr Road						
East of Dairy Road	296	A	216	512	A	**73%**
Station Road						
West of Morris Road	231	A	682	913	A	**295%**
Morris Road						
South of Stockdale Highway	286	A	682	968	A	**238%**
Wasco Way						
North of Stockdale Highway	1,892	A	0	1,892	A	0%
Tupman Road						
South of Adohr Road	132	A	216	348	A	**164%**
North of SR 119	660	A	108	768	A	16%

Source: URS 2012b, p. 159-1 – 159-3,160-1 – 160-4
Bold text indicates substantial increase in number of vehicle trips (50% increase or greater)

Traffic and Transportation Table 11
Current and Anticipated Year 2016 With and Without Project Roadway Segment AADT LOS – Operation – Alternate 2 (Truck Transportation)

Roadway Segment	Baseline AADT (2017)	LOS	Project Added AADT	Baseline Plus Project AADT	LOS	Increase in AADT (%)
Interstate 5						
North of Stockdale Highway	37,620	A	578	38,198	A	2%
South of Stockdale Highway	35,340	A	378	35,718	A	1%
State Route 43						
North of Stockdale Highway	6,270	A	1,366	7,636	A	22%
North of SR 58	10,260	B	1,366	11,626	C	13%
South of 7th Standard	5,700	A	1,366	7,066	A	24%
South of Lerdo Highway	11,400	C	1,366	12,766	D	12%
South of Poso Avenue	11,628	C	691	12,319	D	6%
State Route 119						
East of Tupman Road	12,084	D	92	12,176	D	1%
Stockdale Highway						
West of Dairy Road	1,837	A	0	1,837	A	0%
West of I-5	2,046	A	2,782	4,828	A	**136%**
East of I-5	4,664	A	1,582	6,246	A	34%
Dairy Road						
South of Stockdale Highway	205	A	270	475	A	**132%**
Adohr Road						
East of Dairy Road	296	A	216	512	A	**73%**
Station Road						
West of Morris Road	231	A	2,512	2,743	A	**1,087%**
Morris Road						
South of Stockdale Highway	286	A	2,512	2,798	A	**878%**
Wasco Way						
North of Stockdale Highway	1,892	A	0	1,892	A	0%
Wasco Avenue (Wasco)						
South of Poso Avenue	1,507	A	675	2,182	A	48%
Tupman Road						
South of Adohr Road	132	A	216	348	A	**164%**
North of SR 119	660	A	108	768	A	16%
J Street (Wasco)						
North of Poso Avenue	2,123	A	1,350	3,473	A	**64%**
South of 9th Street	781	A	675	1,456	A	**86%**
H Street (Wasco)						
South of 9th Street	1,155	A	675	1,830	A	**58%**
Kimberlina Road (Wasco)						
East of SR 43	3,850	A	675	4,525	A	18%
Poso Avenue (Wasco)						
East of SR 43	2,805	A	675	3,480	A	24%
9th Street (Wasco)						
East of H Street	352	A	675	1,027	A	**192%**

Source: URS 2012b, p. 159-1 – 159-3,160-1 – 160-4
Bold text indicates substantial increase in number of vehicle trips (50% increase or greater)

Kern Council of Governments Regional Transportation Plan

California State Proposition 111, passed by voters in 1990, established a requirement that urbanized areas prepare and regularly update a Congestion Management Program (CMP). The purpose of the CMP is to monitor the performance of the countywide transportation system, develop programs to address near-term and long-term congestion, and better integrate transportation and land use planning. The Kern Council of Governments (KCOG), as the designated Congestion Management Agency for the Kern County region, must develop, adopt, and regularly update the CMP.

The 2011 KCOG Final Regional Transportation Plan (RTP) identifies the I-5, SR 119, SR 58, and SR 43 highways as CMP roadways (KCOG 2010, p. 4-107). The RTP identifies that all roadway segments on the Congestion Management network shall maintain a LOS E or better (KCOG 2010, p. 4-109). As discussed above, proposed project construction traffic would impact both the SR 43/Stockdale Highway and SR 119/Tupman Road intersections, which are projected to degrade to LOS F, thus violating designated KCOG RTP thresholds. However, Conditions of Certification **TRANS-1** and **TRANS-2** will reduce impacts from construction related trips at these intersections. As shown in **Traffic and Transportation Tables 10, 11, 12, and 13**, operations-related traffic associated with the project would not impact or deteriorate any project area intersections or roadway segments to below an LOS E. Therefore, impacts to CMP designated roadways that would occur from construction- or operational-related HECA project traffic would be reduced upon the implementation of Conditions of Certification **TRANS-1** and **TRANS-2**.

As shown in Traffic and Transportation **Tables 10 and 11**, operation activities associated with the project would substantially increase the number of trips on certain roadways segments and would equally increase trips through specific intersections near the HECA project site including Morris Road/Stockdale Highway, Dairy Road/Stockdale Highway, Dairy Road/Adohr Road, and Station Road/Tupman Road. In addition, operation of the project without the rail spur component would substantially increase the number of trips on certain roadway segments and subsequent intersections in the city of Wasco including J Street/H Street, 9th Street/H Street, and 9th Street/J Street. Each of these intersections are currently stop controlled in only one direction (through traffic is unimpeded while adjoining traffic is required to stop).

The resulting increase in truck traffic would alter the accident risks for local road users in the project vicinity. This truck traffic increase could cause traffic congestion which could, thereby, increase the number of accidents. However, congestion may actually reduce the number of injuries and fatalities associated with those accidents. A complex relationship exists between traffic congestion and vehicular accidents. While less congested roads lead to fewer accidents, in general, less congested roads also frequently reduce speeds, thereby reducing the severity of accidents that do occur (AAA, 2011). However, heavy truck loads weigh 5 to 10 times as much as passenger vehicles. It should be stated that farm equipment is considered the same as passenger vehicles for the purposes of accidents. Collisions between heavy trucks and passenger vehicles tend to increase the severity of accidents, increase the number of injuries, increase the severity of injuries, and increase the number of fatalities per accident for occupants in passenger cars by nearly a factor of 10 (Scott and O'Day, 1971; AAA, 2011).

While it is not possible to accurately quantify or estimate the net result of interaction between these relative risk factors, the applicant is proposing improvements to four intersections (i.e., SR 43/Stockdale Highway, SR 119/Tupman Road, Dairy Road/Adohr Road, Dairy Road/Stockdale Highway) to reduce LOS impacts (URS 2012, p. 5.10-13). Staff recommends improvements at five additional intersections (i.e., Morris Road/Stockdale Highway, Station Road/Tupman Road, J Street/H Street, 9th Street/H Street, 9th Street/J Street) to reduce the potential for accidents. To ensure these improvements are made, Condition of Certification **TRANS-2** is proposed and would require physical improvements at these intersections. Implementation of Condition of Certification **TRANS-2** would significantly reduce the frequency of collisions between passenger vehicles and heavy trucks in the project vicinity. With these intersection improvements, staff concludes there would not be a significant impact on vehicular injury and fatality rates associated with increased truck traffic in the project vicinity as compared to the existing truck traffic conditions without the project.

Rail

The proposed project would construct a new rail spur that connects to the Buttonwillow Subdivision rail line located north of the HECA site. The spur would be approximately 5 miles long. The SJVRR operates the Buttonwillow Subdivision which extends 33 route miles between Buttonwillow and Kern Junction. The line connects with UPRR at Kern Junction (KCOG 2012, p. 2). The spur would be dedicated solely for deliveries to and from HECA and no stops would be made between the Buttonwillow Subdivision rail line and the HECA site.

Operation of the rail spur would require public road crossings at Stockdale Highway and Adohr Road. Design and operation of the rail line, including the public road crossings, are regulated under numerous rules and regulations codified in the Public Utilities Code and in Title 20, California Code of Regulations, Division 1 to reduce roadway crossing hazards and ensure safe operation. These rules and regulations are traditionally within the California Public Utilities Commission's (CPUC) jurisdiction to implement and enforce. At the time of this Preliminary Staff Assessment (PSA), specific designs for the road crossings have not been provided to Energy Commission staff. The applicant conducted a field visit with CPUC staff at the proposed site for the rail line on February 7, 2013. During the field visit, the applicant provided design drawings of the proposed rail line for CPUC staff to look at.

Because the rail spur is dedicated to HECA (it will only be used for delivery to and from the project) and essential to its operation (it is necessary for delivery of the fuel needed to operate the project) it is by definition a related facility and, thus, subject to the Energy Commission's jurisdiction. Nevertheless, because the CPUC traditionally has jurisdiction over such facilities, staff continues to coordinate closely with the CPUC to ensure appropriate design of the rail line for safe operation. In order to ensure that CPUC staff has sufficient information in order to help analyze the proposal, the applicant must submit a formal application pursuant to Title 20, California Code of Regulations, section 3.1.

The HECA project site is designed to allow for an entire train to be located completely onsite, and remain onsite, during offloading of coal. Specifically, the HECA site incorporates two loops for the rail line, one loop inside the other, located on the eastern third of the project site. The outer loop would be nearly 15,000 feet (2.8 miles) in length and the inner loop would be approximately 14,000 feet (2.6 miles) in length. In addition, the rail line extends from the northwestern corner of the HECA site to the northeastern portion of the site for approximately 4,700 feet (0.9 mile) which would provide additional onsite parking for trains. In total, the HECA project provides approximately 33,700 feet (6.4 miles) of rail line completely onsite for parking during the process of offloading the coal.

The HECA project would require the use of 200 train cars per day during maximum operations for delivery of coal. Assuming the project would use standard hopper cars to transport coal to the HECA site, a train with 200 hopper cars would be approximately 10,000 feet (1.9 miles) in length (refer to **Traffic and Transportation Table 12** below). Based on this project site design and train dimensions, trains used during maximum project operations would be adequately accommodated on the HECA site during the process of offloading the coal.

Traffic and Transportation Table 12
Individual Train Lengths – Maximum Operations

Component	Number	Length (feet)	Total Length (feet)
Hopper car	200	45.5	9,100
Tongues	200	4	800
Engines	5	73	365
TOTAL			**10,265**

Sources: Enviromodal, 2012; Northeastern Railroad, 2012.

Enhanced Oil Recovery (EOR)

The OEHI CO_2 EOR Project (OEHI) would generate 25 new vehicle trips during the operational phase that would occur over a 20-year timeframe. Implementation of the OEHI project would account for a maximum of 8 percent of existing peak hour traffic at any one project area intersection. In addition, Caltrans proposes improvements to SR 119 in the OEHI project area, including intersections potentially used by 25 full-time positions. Therefore, vehicle trips generated by operation of the OEHI project would not substantially degrade any intersection LOS and impacts are considered to be less-than-significant.

Parking

During construction, all temporary construction equipment laydown and parking, including construction parking, offices, and construction laydown areas, would be located within the proposed project site (URS 2012a, p. 2-56). Therefore, no off-site construction worker parking would occur during construction of the proposed project. Once operational, worker parking would be located within the HECA site. Staff is proposing Condition of Certification **LAND-3** to ensure internal operational employee parking requirements are consistent with Kern County regulations (Zoning Ordinance sections 19.82.030 and 19.82.090 [Off-street Parking - Design and Development

Standards]) and are met by the proposed HECA project. Specifically, Condition of Certification **LAND-3** would require the project owner to submit a site development plan, which conforms with Kern County regulations relating to parking, to Kern County and the Energy Commission for review and approval. With the incorporation of this condition, both construction and operation of the proposed project would have no impact on parking resources serving the area.

Hazardous Materials / Waste Transportation

Quantities of hazardous materials needed onsite during construction are anticipated to be small (URS 2012a, p. 5.10-13). Over the course of construction, one or two truck deliveries of hazardous materials would be required. Hazardous materials to be used during construction may include gasoline, diesel fuel, oil, and lubricants, as well as minimal amounts of cleaners, solvents, adhesives, and paint materials. Acutely Hazardous Materials (AHMs) will not be used or stored on site during construction and storage of hazardous materials will not occur outside of the HECA project site (URS 2012a, p. 5.12-4).

Project operations would require regular transportation of two hazardous materials (methanol and caustic [sodium hydroxide]) to the HECA project site (URS 2012a, p. 5.12-19). The total number of truck deliveries, maximum of 30 truck trips per day, from the site during project operations would be low and infrequent as compared to trips generated during peak daily operation (see **Traffic and Transportation Table 7**) (URS 2012a, p. 5.12-19 and -20). Therefore, the number of hazardous materials truck deliveries would not cause a significant impact to traffic congestion or LOS.

The applicant's proposed routes for hazardous materials delivery to and from the HECA project site would be I-5 to Stockdale Highway west, then Morris Road south to Station Road, right on Station Road to the HECA project site along Tupman Road (URS 2012a, p. 5.12-19 and -20). Staff also reviewed routes to four potential customers for degassed liquid sulfur identified in the AFC. These routes would avoid sensitive receptor locations, such as schools and daycare facilities.

The proposed truck routes appear to be consistent with all relevant jurisdictions' regulations related to hazardous materials transportation routes. However, to further ensure that the truck routes used comply with limitations set by local jurisdictions and Caltrans, staff has included Condition of Certification **TRANS-5** to require the project owner to obtain any necessary permits from Caltrans and any relevant local jurisdictions, including Kern County and city of Bakersfield.

Delivery of materials, such as methanol and caustic (sodium hydroxide), to the HECA project site could be hazardous to the public if a spill were to occur. The HECA project would also produce certain hazardous materials that would primarily be used onsite to produce nitrogen-based products. However, some of the surplus materials may be sold and transported offsite on tanker trucks and/or railcars. Similarly, transportation of these materials (i.e., degassed liquid sulfur), from the HECA project site could be hazardous to the public if a spill were to occur.

The likelihood of an accident-caused spill would be lower during low traffic periods, and if a spill were to occur during these hours, fewer commuters would be exposed. Therefore, staff recommends Condition of Certification **TRANS-5** to ensure that all deliveries of hazardous materials would occur outside of normal commute hours. **TRANS-5** would also require that the project owner obtain all the proper permits and/or licenses from Caltrans, Kern County, and city of Bakersfield for transporting hazardous materials.

In addition, oversized or overweight trucks with unlicensed drivers could be hazardous to the general public and/or damage roadways. To mitigate this hazard, Condition of Certification **TRANS-6** also requires that the project owner comply with local jurisdictions' and Caltrans' limits on vehicle sizes and weights and driver licensing regulations.

For a more detailed discussion on the handling and disposal of hazardous substances, see the **Hazardous Materials Management** and **Waste Management** sections of this PSA.

Emergency Access

In the event of an emergency at the HECA project site during construction, emergency vehicles would likely use either Dairy Road or Tupman Road and existing driveways to access the project site. To maintain temporary access for emergency vehicles and allow for adequate access into the facility, proposed Condition of Certification **TRANS-1** requires the preparation of a construction traffic control plan, which includes the assurance of access and movement of emergency vehicles. Furthermore, all internal access roadways would be designed consistent with Kern County standards (Kern County General Plan Circulation Element Policy 4) to provide adequate room for emergency vehicles to navigate within the facility boundaries and internal circulation roadways. As discussed in the **Worker Safety and Fire Protection** section in this PSA, Condition of Certification **WORKER SAFETY-6** requires the project owner to identify and identify three secure access points for emergency personnel to enter the site. These access points and the method of gate operation would be required to be submitted to the Kern County Fire Department for review and comment and to the CPM for review and approval. These conditions would ensure emergency access is provided during both HECA construction and operation, resulting in less than significant impacts to emergency access.

ASSESSMENT OF IMPACTS TO OTHER TRANSPORTATION SYSTEMS

Passenger Rail

The closest passenger rail service to the HECA project site is provided by Amtrak. Amtrak operates the San Joaquin train route which has stops in the city of Bakersfield and city of Wasco. The San Joaquin route runs multiple times daily between the San Francisco Bay Area (or Sacramento) and Bakersfield (Amtrak 2013). The Amtrak station is located approximately 18 miles north of the HECA project site in the city of Wasco. The Amtrak station located in Bakersfield is approximately 21 miles to the east of the project site.

Construction and operation activities associated with the proposed HECA project would not result in any effects to the operation of passenger rail in the project area.

Bus Service

The nearest KRT bus line to the proposed HECA project site is the Buttonwillow Route located approximately 3.9 miles northwest of the project site (Kern County 2012). Therefore, no local bus stops are in immediate proximity of the HECA site.

As indicated earlier in this analysis, the HECA project would generate 2,460 daily trips during construction and could generate nearly 3,000 daily trips during operations (Alternative 2). See **Traffic and Transportation Table 2** and **Table 7**. However, these increased trips would not conflict with the operation of bus service in the project area.

Bicycle and Pedestrian Facilities

Based on the 2001 Kern County Bicycle Plan and visual inspections of the proposed HECA site, no existing or planned bicycle facilities are within the immediate vicinity of the project site (KCOG 2001, p. 10). However, operation of the proposed project could create truck trips in further reaches of Kern County, including the cities of Shafter and Wasco. According to the Kern County Bicycle Facilities Plan (2001) and confirmed by Energy Commission staff, there is no adopted bicycle plan and there are no bicycle travel facilities provided in the community of Shafter. As for the community of Wasco, the Plan identifies two existing bicycle facilities including a looped Class I bike path around Westside Park and a Class 1 bike path on the south side of Barker Park from Maple Avenue to Birch Avenue. It should be noted the Kern County Bicycle Facilities Plan identifies planned bicycle facilities in Shafter along SR 43 between Tulare Avenue and Riverside Street (KCOG 2001, p. 31).

Staff researched Bakersfield-area bike clubs to attempt to determine if any popular bike routes used roadways near the HECA project site. It was found that one organized group ride begins and ends in Buttonwillow with a route that travels along SR 58 and the McKittrick grade (Kern Wheelmen Bicycle Club 2013).

As indicated earlier in this analysis, the HECA project would generate 2,460 daily trips during construction and could generate nearly 3,000 daily trips during operations (Alternative 2). See **Traffic and Transportation Table 2** and **Table 7**. However, these increased trips would not conflict with any existing or planned bicycle or pedestrian facilities. In addition, project-generated trips would not increase hazards to bicyclists or pedestrians along any existing or planned facilities.

Airports/Aviation Activities

Aviation Background

One existing airport is currently operating in the vicinity of the HECA project site. This airport includes the Elk Hills-Buttonwillow Airport, located approximately 4.6 miles west of the HECA project site.

Elk Hills-Buttonwillow Airport

Elk Hills-Buttonwillow Airport is a general aviation airport with one runway, runway 11/29 oriented northwest/southeast. Elk Hills-Buttonwillow Airport is owned by the Kern County Department of Airports and serves agricultural and other general aviation activities. For the one-year time frame ending April 25, 2011 (most recently published statistic), the Elk Hills-Buttonwillow Airport handled an average of 23 aircraft per week, of which 100 percent was transient general aviation. Elk Hills-Buttonwillow Airport runway 11/29 observes a recommended right turn traffic pattern when departing Runway 11 (to the northwest) and a recommended left turn traffic pattern when departing Runway 29 (to the southeast), directing aircraft toward the proposed HECA project site (AirNav 2012).

Airspace

The proposed HECA project site and Elk Hills-Buttonwillow Airport lie beneath Class E airspace. A Class E surface area is designated to provide controlled airspace for terminal operations where a control tower is not in operation. Class E surface areas extend upward from the surface to a designated altitude; or to the adjacent or overlaying controlled airspace (FAA Order JO 7400.2J, *Procedures for Handling Airspace Matters*, Section 18-1-2(a)).

The HECA project site is considered to be located in a sparsely populated area. According to FAA regulations, aircraft must maintain an altitude of at least 500 feet above ground level (AGL) above any person, vessel, vehicle, or structure in sparsely populated areas (14 C.F.R., § 91.119).

Using the longitude and latitude of the HECA feedstock dryer and gasification structure (tallest structures proposed), the HECA project was run through the California Military Land Use Compatibility Analysis (CMLUCA) database to determine if the HECA site is located within 1,000 feet of a military installation, is located within military based special use airspace, or is located beneath a military designated low-level flight path. Based on the CMLUCA report, the proposed HECA project does not intersect with any military bases, special use airspaces, or low level flight paths (CMLUCA 2012).

Aviation Impacts

To assess the HECA project's aviation impacts, staff examined whether the project's construction equipment, project structures, gen-tie structures, and/or thermal plumes could obstruct airspace and findings are discussed later in this analysis.

Construction and Structure Heights

Staff has been advised by the applicant that during construction, tall equipment, such as cranes and derricks, would be in use on the project site. Title 14, Part 77.9 of the Code of Federal Regulations requires FAA notification for any proposed structure over 200 feet in height AGL, regardless of the distance from an airport. The HECA project includes several structures taller than 200 feet, with the project's tallest structures proposed including the feedstock dryer and gasification structure, each at 305 feet in height (URS 2012a, Figure 2-6). Construction associated with HECA triggers the need for the project owner to file FAA Form 7460-1, *Notice of Proposed Construction or*

Alteration, in accordance with FAA CFR Title 14 Part 77.9 because the project would use structures or equipment (e.g., cranes) that are greater than 200 feet in height.

On June 25, 2012 the HECA applicant obtained from the FAA a *Determination of No Hazard to Air Navigation*, stating that all HECA structures would pose no safety impact to aircraft operations (FAA 2012). This determination includes temporary construction equipment (e.g., cranes, derricks) which may be used during construction of the structure. Equipment which has a height greater than the studied structure requires separate notice to the FAA (FAA 2012). To ensure compliance with the FAA 7460 Determination of No Hazard to Air Navigation, Condition of Certification **TRANS-8** is required to satisfy the FAA determination of no hazard to air navigation by requiring the project owner to ensure that any temporary or permanent structure, including all appurtenances, that exceeds an overall height of 200-feet AGL be marked and/or lighted consistent with FAA Advisory Circular 70/7460-1 K Change 2, Obstruction Lighting/Marking Requirements. The incorporation of this condition would ensure less than significant impacts to Elk Hills-Buttonwillow Airport air traffic operations from project structures would occur. Therefore, the project is consistent with both FAA and Kern County ALUCP LORS.

Thermal Plumes

HECA main gas turbine/heat recovery steam generator (HRSG) operation and wet cooling tower exhaust would result in thermal air plumes during project operation. Thermal plumes have the ability to impact low flying aircraft and could cause moderate to severe turbulence to low-flying aircraft above the HECA site. The FAA formally acknowledged plume hazards by amending the Aeronautical Information Publication to establish thermal plumes as flight hazards and recommend that pilots avoid overflight below 1,000 feet and fly upwind of facilities producing thermal plumes (FAA 2011). Aircraft flying through plumes can experience significant air disturbances, such as turbulence and vertical shear.

A plume velocity analysis was conducted for the HECA project and is presented in detail as APPENDIX TT-1 of this PSA. As described in APPENDIX TT-1, worst-case analysis for plume sources was used (please refer to APPENDIX TT-1 for an explanation of these conditions). The worst-case airspace conditions used in the velocity calculations are a frequent natural occurrence and would presumably occur during the life of the power plant and potentially when small aircraft fly above HECA site.

Energy Commission staff uses a 4.3 meters per second (m/s) vertical velocity threshold[3] for determining whether a plume may pose a hazard to aircraft. This velocity generally defines the point at which general aviation aircraft would begin to experience more than light turbulence. Exhaust plumes with high vertical velocities may damage aircraft airframes or cause turbulence resulting in loss of aircraft control and maneuverability (FAA 2006). As shown in APPENDIX TT-1, the calculated worst case calm wind

[3] This is based on staff's review of a 2004 safety circular (AC 139-05(0)), prepared by the Australian Government Civil Aviation Safety Authority, that noted "aviation authorities have established that an exhaust plume with a vertical velocity in excess of 4.3 meters per second (m/s) may cause damage to an aircraft airframe or upset an aircraft when flying at low levels" (CASA 2004). In their safety study on thermal plumes, FAA regulators noted that they "do not necessarily approve/disapprove or warrant the data contained in the CASA AC 139-05." The safety team accepted "the information and data contained in AC 139-05 as a valid representation of hazardous exhaust velocities" (FAA 2006).

condition vertical plume average velocities from the HECA gas turbine/HRSG are not predicted to exceed 4.3 m/s at heights at or above 730 feet above ground level (AGL).

As described above in the environmental setting discussion of airports, Elk Hills-Buttonwillow Airport runway 11/29 observes a recommended right turn traffic pattern when departing Runway 11 (to the northwest) and a recommended left turn traffic pattern when departing Runway 29 (to the southeast), directing aircraft toward the proposed HECA project site (AirNav 2012). While recommended traffic patterns of Elk Hills-Buttonwillow Airport direct traffic toward the HECA site, the proposed HECA project site is approximately 4.6 miles southeast of the Elk Hills-Buttonwillow Airport. As indicated, the Elk Hills-Buttonwillow Airport handled an average of 23 aircraft per week, of which 100 percent were transient general aviation (AirNav 2012). As these aircraft have the potential to fly below 730 feet AGL above the HECA site, staff concludes there is the potential for thermal plumes from the HECA project to impact aircraft utilizing Elk Hills-Buttonwillow Airport. Staff is proposing Condition of Certification **TRANS-8**, which will require the project owner to work with the FAA to notify all pilots using Elk Hills-Buttonwillow Airport and to update all airspace charts that include the HECA site to announce that invisible air plume hazards could exist and pilots should avoid direct overflight below 730 feet AGL.

All land uses within one-mile of the project site are farmland or operations in support of agricultural activities (URS 2012a, p. 5.4-24). Therefore, agricultural production in the vicinity of the HECA site may use aeronautic crop dusting aircraft that fly at a low altitude (500 feet and below) near and over the project site. Based on the findings in APPENDIX TT-1, HECA thermal plume sources could significantly impact crop dusting aircraft operations over the HECA site. To reduce this potential impact, staff is proposing Condition of Certification **TRANS-9**, which will require the project owner to advise the Kern County Agricultural Commissioner that crop-dusting aircraft should avoid direct overflight of the project site. To further reduce potential impacts related to crop dusting aircraft operations, staff is proposing Condition of Certification **TRANS-10**, which will require the project owner to include marker balls on the proposed 230 kV transmission line interconnect between the HECA site and PG&E Midway Substation. The incorporation of these conditions into the proposed project will reduce potential impacts to low flying crop dusting aircraft to a less-than-significant level.

Aircraft Communications

Walkie-talkies and other communications equipment planned for use during construction would not interfere with frequencies used for aviation communication. HECA communications equipment (e.g., walkie-talkies) would typically operate in the 27 or 400 to 500 megahertz ranges, which do not coincide with the communication frequencies used by aircraft in the vicinity, which are 122.9, 121.125, 115.40, 117.50, and 117.10, megahertz (AirNav 2012). Therefore, the proposed HECA project is consistent with Policies 3.3.5(c) and 3.5.5(a)(4) of the *County of Kern Airport Land Use Compatibility Plan (March 29, 2011)*, which prohibits land use characteristics that may produce hazards to aircraft in flight including sources of electrical interference with aircraft communications or navigation.

Hazards and Public Safety

Increased vehicle activity during construction has the potential to create impacts to motorist and public safety. Although heavy trucks serve agricultural operations in the project area, existing heavy truck operations are infrequent. Implementation of the HECA project under the no rail spur option would substantially increase the frequency of heavy truck operations on local roadways (e.g., Morris Road, Station Road). Potential construction vehicle impacts would be minimized to the maximum extent feasible by proposed Condition of Certification **TRANS-1** which requires preparation of a construction traffic control plan that includes use of flagging and covering open trenches, would minimize hazards due to possible traffic stacking as construction workers enter and exit the project site when their shifts begin and end, and would divert construction-related traffic to the maximum extent feasible away from residential areas.

The Kern County Roads Department has indicated that Dairy Road and Adohr Road are not currently of adequate design or capability to accommodate heavy truck traffic that would be generated by the proposed project without the rail spur under Alternative 2 (Kern County 2010). There would be a potential for unexpected damage to roads by vehicles and equipment within the project area that could result in a roadway hazard to the public. Therefore, staff proposes Conditions of Certification **TRANS-3** and **TRANS-4**. Implementation of Condition of Certification **TRANS-3** would require a pavement test be conducted along with redesigning and repaving of all public roads, easements, and rights-of-way that would be utilized by the project to a standard that accommodates heavy trucks. Implementation of Condition of Certification **TRANS-4** would require any road damaged by project construction and operation be repaired to its original condition. This would ensure that any damage to local roadways would not be a safety hazard to motorists.

The use of oversize vehicles during construction could create a hazard to the public by limiting motorist views on roadways and by the obstruction of space. As described above in **Traffic and Transportation Table 1**, California Vehicle Code sections 35550-35559 establish guidelines for oversize vehicle loads. To ensure consistency with these applicable ordinances, staff proposes Condition of Certification **TRANS-6**, which would require that all oversize vehicles used on public roadways during construction comply with Caltrans, Kern County, and other relevant jurisdictions' limitations on vehicle sizes and weights, as well as use oversize vehicle routes and any other applicable limitations or other relevant jurisdictional policies.

The implementation of Conditions of Certification **TRANS-1**, **TRANS-3**, **TRANS-5**, and **TRANS-6** would ensure that the proposed project results in less than significant hazard and safety impacts to motorists and ensures project compliance to LORS pertaining to such.

School Traffic

The HECA site is located in the Elk Hills School District (EHSD) and Taft Union High School District (TUHSD). However, operation of the proposed project under Alternative 2 (truck transportation) would place an increased volume of heavy trucks on roadways between the HECA site and Wasco. This route would traverse the Richland School District (RSD), which serves the community of Shafter, and Wasco Union High School

District (WUHSD) and Wasco Union Elementary School District (WUESD). Staff reviewed the bus routes for each school district and determined that project-related truck trips would not increase hazards to school traffic because truck trips would be spread throughout the day (not conglomerated into morning or afternoon hours) and there are not any bus stops located along the truck routes (EHSD, TUHSD, RSD, WUHSD, WUESD; 2012).

Farm Machinery Traffic

The HECA project site is located in a predominantly agricultural area. All land uses within one-mile of the project site are farmland or operations in support of agricultural activities (URS 2012a, p. 5.4-24). Therefore, agricultural production in the vicinity of the HECA site will likely lead to farm machinery being driven on roadways near the project site. However, traffic associated with construction and operation of the proposed project would be limited to specific roadways outside of a highway including Morris Road, Station Road, and Dairy Road. There is the potential for farm machinery and project-related heavy trucks to utilize these roadways at the same time. Although there are numerous adjacent roads (e.g., private dirt roads) that can be used by farm equipment to reduce the need for using a public roadway, the proposed project has the potential to disrupt farming activities and create a traffic hazard resulting from heavy trucks and farm machinery using certain public roadways at the same time. Therefore, staff proposes Condition of Certification **TRANS-1** which would require the applicant to prepare traffic control plan that addresses the safe operation of heavy trucks and farm machinery on the same public roadway. The incorporation of this condition into the proposed project will reduce potential impacts to farm machinery traffic.

In addition, the HECA project could disrupt local farming activities with a proposed rail spur which would block access along private roads. As shown in **Traffic and Transportation Figure 1-3**, the proposed rail spur would cross multiple private roads and potentially cut east-west access along these private roads. Blocking these private roads could prevent the movement of farm equipment between adjacent fields.

As shown in **Traffic and Transportation Figure 1-3**, the applicant is proposing construction of rail safety devices at six private at-grade crossings including warning devices (i.e., CPUC standard No. 1-X private crossing sign) and concrete roadway surfaces at six locations along the rail spur. It should be noted the CPUC does not issue permits for private crossings (though they may intercede if complaints over a private crossing are filed). An agreement to construct a private crossing would occur exclusively between the rail spur property holder (i.e., HECA project owner) and those seeking to build the private crossing. The builder of the private crossing would be required to ensure it is not publicly used. With construction of these private at-grade rail crossings, east-west access along private roads would continue to be allowed and disruption to farming activities would not occur. However, each rail crossing would create a point of risk associated with the potential for conflict between motor vehicles (e.g., farm machinery) and trains. Therefore, the CPUC generally recommends that rail crossings be minimized to the extent feasible. Staff currently has no information concerning the analysis the applicant conducted in determining that private at-grade crossings were needed at each of the identified locations. Therefore, staff requests the applicant provide such an analysis and attempt to further reduce the number of crossings proposed. This analysis should also discuss potential impacts to the movement of farm machinery and equipment due to reduced crossings, and should identify to what extent lands on either side of the proposed spur are owned and maintained by the same person or entity, and, thus, could possibly be impacted by reduced connectivity. Additionally, staff requests that the applicant submit to the CPUC and Energy Commission staff all the information that would otherwise be required for an application for authority to construct a new public rail crossing at the two locations proposed.

Tule Fog and Ground Fogging

The HECA project site is located in a geographic area prone to Tule fog. Ground fog is created when weather conditions in the Central Valley are stable, when air remains moist and still, and when the ground cools through the night and chills the air. Over time the moist air condenses and forms a ground-hugging cloud, or Tule fog. Tule fog is a seasonal phenomenon that occurs primarily in the Sacramento and San Joaquin valleys during the late fall and winter months because the low angle of the sun does not create enough heat for the fog to evaporate, therefore, the fog never dissipates.

Visibility in Tule fog is usually less than an eighth of a mile (approximately 600 feet) but can be as little as one foot. Variability in visibility can be a cause of chain-reaction accidents on roads and freeways. The Highway Patrol does not provide regional accident statistics; however, statewide highway fatalities mirror the Central Valley fog patterns (Los Angeles Times 1989).

According to the applicant’s estimate of monthly construction labor power (URS 2012a, Table 2-25), periods of heavy construction activities would occur over a minimum of one year. Therefore, it can be assumed that heavy construction truck traffic could occur during the late fall and winter months when Tule fog has the greatest potential to form.

Although construction and operation of the project could place trucks on roadways during events of Tule fog, truck speeds would be reduced depending on conditions (e.g., fog, rain) affecting the roadway surface and visibility. Safe operation of vehicles and trucks is regulated by the California Vehicle Code. Specifically, sections 24400 through 24411 require the equipping and use of lights during inclement weather. Section 22350 of the vehicle code requires a person to not drive a vehicle at a speed greater than is reasonable or prudent for weather and visibility. Compliance of truck drivers with regulations of the California Vehicle Code would ensure safe operation of trucks and would not create a traffic hazard associated with Tule fog.

In addition to natural occurring Tule fog, operation of the HECA project has the potential to create ground fog from the air separation unit (ASU) cooling tower. The Seasonal/Annual Cooling Tower Impacts (SACTI) model was used to determine frequency and direction of potential plume ground fogging events that could impact traffic safety along Adohr Road, Dairy Road, and Tupman Road adjacent to the project site. The center of ASU cooling tower is located approximately 3,445 feet south of the intersection of Dairy Road and Adohr Road and approximately 4,990 feet west of Tupman Road.

Staff modeled different project operating conditions to determine the worst case ground fogging plume for the ASU cooling tower which would occur at colder ambient conditions and when 3 of the 4 cells would be in operation. Based on the model, a ground fogging plume could occur up to a distance of 1,000 feet from the ASU. The ground fogging plume is predicted to occur for only a few hours during the four years of meteorological data modeled (see **Appendix VR-2, Visual Plume Modeling Analysis** within the **Visual Resources** section). Therefore, the ground fogging plume would not impact traffic safety along roadways in the project area.

COMPLIANCE WITH LORS

Traffic and Transportation Table 13 provides a general description of applicable laws, ordinances, and regulations (LORS) applicable to the proposed HECA project and pertaining to traffic and transportation.

Additionally, staff has reviewed **Socioeconomics Figure 1**, which shows the environmental justice population (see the **Socioeconomics** and **Executive Summary** sections of this PSA for further discussion of environmental justice) is greater than fifty percent within a six-mile buffer of the proposed HECA project. As discussed in the **Socioeconomics** section, the minority population in the six-mile buffer of the project site constitutes an environmental justice population as defined by *Environmental Justice: Guidance Under the National Environmental Policy Act*.

Staff has proposed Conditions of Certification **TRANS-1 through TRANS-6** that would reduce impacts associated with traffic and transportation; therefore, staff concludes that there would be no significant impact from construction or operation of the HECA project on minority populations. Therefore, there would not be a disproportionate Traffic and Transportation impact resulting from construction and operation of the proposed project to an environmental justice population.

Traffic and Transportation Table 13
Project Compliance with Adopted Traffic and Transportation Laws, Ordinances Regulations, and Standards

Applicable Law	LORS Description and Project Compliance Assessment
Federal	
Title 14, CFR, section 77 (14 CFR 77)	Includes standards for determining physical obstructions to navigable airspace. Sets forth requirements for notice to the Federal Aviation Administration of certain proposed construction or alterations. Also provides for aeronautical studies of obstructions to air navigation to determine their effect on the safe and efficient use of airspace (including temporary flight restrictions).
	On June 25, 2012 the FAA filed a Determination of No Hazard to Air Navigation stating that all HECA structures would pose no safety impact to aircraft operations. To ensure compliance with the FAA 7460 Determination of No Hazard to Air Navigation, Condition of Certification **TRANS-8** is required to ensure that any temporary or permanent structure, including all appurtenances, that exceeds an overall height of 200-feet above ground level (AGL) would be marked and/or lighted consistent with FAA Advisory Circular 70/7460-1 K Change 2, Obstruction Lighting/Marking Requirements.
CFR, Title 49, Subtitle B	Includes procedures and regulations pertaining to interstate and intrastate transport (includes hazardous materials program procedures) and specifies safety measures for motor carriers and motor vehicles that operate on public highways.
	Enforcement is conducted by state and local law enforcement agencies and through state agency licensing and ministerial permitting (e.g., California Department of Motor Vehicles licensing, Caltrans permits), and/or local agency permitting (e.g., Kern County Department of Public Works permits). For a discussion of the potential impacts related to the transport of hazardous materials, please see the **Hazardous Materials Management** section in this PSA.
State	
California Vehicle Code, div. 1; div. 2, chapter 2.5; div. 6, chap. 2 & 7; div. 13, chap. 5; div. 14; div. 14.1, chap. 1 & 2; div. 14.3; div. 14.7; div. 14.8; div. 15	Includes regulations pertaining to licensing, size, weight, and load of vehicles operated on highways; safe operation of vehicles; and the transportation of hazardous materials.
	Enforcement is provided by state and local law enforcement agencies and through ministerial state agency licensing and permitting and/or local agency permitting. The use of oversize vehicles during construction can create a hazard to the public by limiting motorist views on roadways and by the obstruction of space by the oversize vehicle. Therefore, staff proposes Condition of Certification **TRANS-9**, which would require that all oversize vehicles used on public roadways during construction comply with Caltrans, Kern County, and other relevant jurisdictions limitations on vehicle sizes and weights.
California Streets and Highway Code, division 1 & 2, chapter 3 & chapter 5.5	Includes regulations for the care and protection of state and county highways and provisions for the issuance of written permits.
	Enforcement is provided by state and local law enforcement and through ministerial state agency licensing and permitting and/or local agency permitting. There is also a potential for unexpected damage to roads by vehicles and equipment within the project area. Therefore, staff proposes Condition of Certification **TRANS-8**, which would require that any road damaged by project construction be repaired to its original condition.
California Manual on Uniform Control Devices (MUTDC) Chapter 6C	Includes regulations for a temporary traffic control plan to be provided for "continuity of function (movement of traffic, pedestrians, bicyclists, transit operations) and access to property/utilities" during any time the normal function of a roadway is suspended.
	Enforcement is provided by state and local law enforcement and through ministerial state agency licensing and permitting and/or local agency permitting. Construction traffic would impact both the SR 43/Stockdale Highway and SR 119/Tupman Road intersections, which are projected to degrade to LOS F

	without mitigation, during the PM peak hour. Therefore, staff proposes Condition of Certification **TRANS-1**, which would require the project owner to prepare and implement a Traffic Control Plan (TCP) prior to construction in order to reduce construction-related traffic impacts. The TCP would require the project owner to address specific construction-related traffic issues such as redirecting traffic, temporary closure of travel lanes, and ensuring access for emergency vehicles.
CPUC General Order 22-B, 26-D, 33-B, 72-B, 75-D, 88-B, 95, 108, 110, 114, 118-A, 125, 126, 135, 145, 161	Includes regulations related to safe operation of railroads.
	Enforcement is provided by state and local law enforcement and through ministerial state agency licensing and permitting and/or local agency permitting. One option for delivery of coal proposed includes construction of a 5-mile long rail spur, which would affect traffic operations and safety on local roadways. Staff is coordinating with the CPUC to analyze the project's conformance with these requirements.
Local	
Kern County Airport Land Use Compatibility Plan (ALUCP) Section 3.3.5	Prohibits land use characteristics that may produce hazards to aircraft in flight including sources of electrical interference with aircraft communications or navigation.
	Walkie-talkies and other communications equipment planned for use during construction would not interfere with frequencies used for aviation communication. HECA communications equipment (e.g., walkie-talkies) would typically operate in the 27 or 400 to 500 megahertz ranges, which do not coincide with the communication frequencies used by aircraft in the vicinity, which are 122.9, 121.125, 115.40, 117.50, and 117.10, megahertz.
Kern County General Plan Transportation Element	• Chapter 2 (Circulation Element), Goal 5, specifies that all county roadways shall operate at a Level of Service (LOS) D or better; • Circulation Element Subsection 2.3.3 (Highway Plan), Goal 5, specifies that all county highways shall operate at a Level of Service (LOS) D or better; and • Circulation Element, Policy 4, specifies that as a condition of private development approval, developers shall build roads needed to access the existing road network. Developers shall build these roads to County standards unless improvements along state routes are necessary then roads shall be built to California Department of Transportation standards. Developers shall locate these roads (width to be determined by the Circulation Plan) along centerlines shown on the circulation diagram map unless otherwise authorized by an approved Specific Plan Line. Developers may build local roads along lines other than those on the circulation diagram map. Developers would negotiate necessary easements to allow this requirement.
	Construction traffic would impact both the SR 43/Stockdale Highway and SR 119/Tupman Road intersections, which are projected to degrade to LOS F without mitigation, during the PM peak hour. Therefore, staff is proposing Conditions of Certification **TRANS-1** and **TRANS-2,** which would require the project owner to prepare and implement a TCP and intersection improvements prior to construction in order to reduce the impact of a decreased LOS at these intersections. Specifically, the TCP would require the project owner to address specific construction-related traffic issues such as redirecting traffic, temporary closure of travel lanes, and ensuring access for emergency vehicles. Intersection improvements would include • Signalization of the SR 43 (Enos Lane)/Stockdale Highway intersection, • Signalization of the SR 119/Tupman Road intersection, • Construction of a separate left-turn lane on the westbound approach of

	Stockdale Highway and a separate right-turn lane on the northbound approach of Dairy Road at the Dairy Road/Stockdale Highway intersection, and • Reconstruction of at the Dairy Road/Adohr Road intersection to accommodate the turning radius needed by large trucks. In a letter to staff dated April 13, 2010, Kern County has indicated that Adohr Road and Tupman Road alignments require a dedication of 45 feet and 55 feet from the centerline of the roads. No facilities or structures can be constructed in this area. If a portion of the proposed facility needs to encroach into those dedications, then a General Plan Amendment would be required to delete or downgrade the alignment. This process requires a hearing before the Board of Supervisors and can only be heard once every 3 months at the scheduled General Plan Amendment window dates. Based on design of facilities at the HECA project site, it would be feasible for the project owner to provide the required dedications. To accommodate these restrictions, Condition of Certification **TRANS-2** requires project owner and/or construction contractor coordination with Kern County prior to making the intersection improvements specified in **TRANS-2**. Furthermore, all internal access roadways would be designed consistent with Kern County standards. As discussed in the **Worker Safety and Fire Protection** section in this PSA, Condition of Certification **WORKER SAFETY-6** requires the project owner to identify and provide a second access point for emergency personnel to enter the site. This access point and the method of gate operation shall be submitted to the Kern County Fire Department for review and comment and to the CPM for review and approval. These conditions would ensure HECA compliance with these Kern County General Plan Goals and Policies.
Kern County Regional Transportation Plan	Chapter 4 (Strategic Investments) of the Regional Transportation Plan (RTP) includes a listing of state highways and principal arterials within Kern County designated as part of the Congestion Management System, including level of service standards (LOS E or greater) for these designated CMP roadways.
	Both SR 43 and SR 119 are classified as CMP roadways by the Kern County RTP. Project construction traffic would impact both the SR 43/Stockdale Highway and SR 119/Tupman Road intersections, which are projected to degrade to LOS F without mitigation during the PM peak hour, thus violating designated KCOG RTP thresholds. However, Conditions of Certification **TRANS-1** and **TRANS-2,** which would require the project owner to prepare a Traffic Control Plan and intersection improvements prior to construction, would reduce impacts from construction related trips on these intersections.

CUMULATIVE IMPACTS AND MITIGATION

A project may result in a significant adverse cumulative impact when its effects are cumulatively considerable. *Cumulatively considerable* means that the incremental effects of an individual project are significant when viewed in connection with the effects of (1) past projects; (2) other current projects; and (3) probable future projects (Cal. Code Regs., tit. 14, § 15130). In this section, staff discusses whether the HECA project could combine with other projects to create cumulatively considerable adverse impacts to traffic and transportation.

Traffic Impacts

To complete this Cumulative Impacts analysis, staff reviewed known past, current, and probable future projects within 6 miles of the proposed HECA project site or located within the cities of Wasco or Shafter. A distance of 6 miles from the HECA project site was chosen after review of pending projects in Kern County, including their location, and the potential for resulting in a cumulative impact. Under the no rail spur option (Alternative 2), the HECA project would involve routine transportation of coal by truck from the city of Wasco. Therefore, pending projects located along the truck route were also reviewed, including those located in Kern County but primarily focused on the cities of Shafter and Wasco.

Continued development of the Kern County area has contributed to congestion on area roadways that would be used by HECA related traffic, including within the communities of Shafter and Wasco. Staff identified no cumulative projects within 6 miles of the HECA site area that could potentially contribute cumulative added trips. Similarly, staff's review of projects in the cities of Shafter and Wasco identified no cumulative projects that would contribute traffic to roadways that would be used by HECA truck traffic as part of Alternative 2.

Consistent with the Kern County Roads Department requirements (URS 2012a, p. 5.10-12), an annual ambient traffic growth of 2 percent was used to establish No Project baselines for Year 2016 construction and Year 2017 operations analysis scenarios, as shown in **Traffic and Transportation Tables 3, 8,** and **9**. Therefore, temporary and permanent roadway congestion resulting from the proposed HECA project that could combine with other projects and growth within the area was considered in the proposed project analysis.

Condition of Certification **TRANS-1,** which would require the project owner to prepare a Construction Traffic Control Plan prior to construction, would reduce the overall potential for temporary project construction traffic to contribute cumulatively to local area traffic delays. However, as discussed earlier, construction-related traffic associated with the proposed project could have the potential to contribute cumulatively to an increase in traffic that could be substantial in relation to the existing traffic load and capacity of two intersections: SR 43/Stockdale Highway and SR 119/Tupman Road. Condition of Certification **TRANS-2** would require physical improvements at the SR 43/Stockdale Highway, SR 119/Tupman Road, Dairy Road/Stockdale Highway, and Dairy Road/Adohr Road intersections to reduce impacts from construction related trips at both the SR 43/Stockdale Highway and SR 119/Tupman Road intersections. These improvements would not only reduce the proposed project potential to contribute to cumulative delays at these intersections, but expand capacity of these intersections for traffic associated with cumulative development that could overlap with the HECA construction schedule. Furthermore, with the intersection improvements required by Condition of Certification **TRANS-2**, construction related traffic associated with the proposed project is not considered by staff to have the potential to contribute to significant cumulative traffic impacts.

Conditions of Certification **TRANS-3** through **TRANS-10** are proposed to reduce the proposed project's potential to contribute cumulatively to aviation, roadway hazards, physical damage to local transportation facilities, and alternative transportation impacts. These conditions would ensure the proposed project's cumulative contribution to these impacts remains less than significant. Furthermore, as the proposed project would not result in impacts to public parking facilities, it would not contribute cumulatively to any parking impacts.

Furthermore, it is assumed that all cumulative project development occurring within Kern County would include environmental review and mitigation similar to that for the proposed project (e.g., development of a construction traffic control plan, necessary roadway improvements) and would require approval from all affected jurisdictions and agencies. Mitigation associated with approval of individual projects would reduce cumulative transportation and traffic impacts as well. As agency approval of projects is gained, jurisdictional staggering of project construction and timing may occur to further reduce any potential cumulative transportation and traffic impacts. Therefore, the proposed project would not have a considerable cumulative contribution to transportation and traffic impacts within the HECA project area.

HECA construction workforce traffic, construction truck traffic, and operational truck traffic would not exclusively travel through areas with an identified high percentage of minority or low-income population. Therefore, the proposed project would not introduce traffic and transportation-related environmental justice issues.

Decommissioning

Decommissioning would not likely occur for at least 20 years and is not expected to result in adverse cumulative traffic and transportation impacts. Generated trips would likely be similar to the trips generated by construction, depending on the duration and extent of decommissioning, including dismantling of facilities and/or site remediation. Any cumulative impacts could be mitigated by staggering construction employees' work schedules or scheduling commute trips for off-peak hours to ensure acceptable LOS levels. Decommissioning would not cause any cumulative impacts to aviation.

NOTEWORTHY PUBLIC BENEFITS

Neither the applicant nor staff has identified any traffic-related benefits associated with the proposed HECA project. While the proposed project would include several improvements to existing intersections and roadways as a result of Conditions of Certification **TRANS-2** through **TRANS-4**, these improvements are necessary to mitigate potential construction and operation traffic impacts and are not considered to be public benefits.

DOE'S FINDINGS REGARDING DIRECT AND INDIRECT IMPACTS OF THE NO-ACTION ALTERNATIVE

Under the No-Action Alternative, DOE would not provide financial assistance to the Applicant for the HECA Project. The Applicant could still elect to construct and operate its project in the absence of financial assistance from DOE, but DOE believes this is unlikely. For the purposes of analysis in the PSA/DEIS, DOE assumes the project would not be constructed under the No-Action Alternative. Accordingly, the No-Action Alternative would have no impacts associated with traffic and transportation.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

Staff received the following comments on aspects of the proposed HECA project related to traffic and transportation:

TOM FRANTZ, ASSOCIATION OF IRRITATED RESIDENTS (TN 66072)

June 29, 2012

Comment: Tom Frantz asks whether the project would receive approval with an option to use either a railroad spur or trucks for delivery of coal from the depot in Wasco.

> **Response:** The proposed HECA project is being analyzed for its potential environmental impacts associated with operating a rail spur under Alternative 1 and operating without a rail spur under Alternative 2.

CHRIS ROMANINI (TN 66249)

July 12, 2012

Comment: Chris Romanini asks where the rail spur will be located.

> **Response:** The proposed HECA project is being analyzed for its potential environmental impacts associated with operating a rail spur under Alternative 1 and operating without a rail spur under Alternative 2.

Comment: Chris Romanini expresses concern with increased volume of vehicles competing with farm equipment, flocks of walking sheep, school buses, and Tule fog.

> **Response:** Project-related haul routes for construction- and project-related traffic are currently utilized by school buses and farm equipment. Please refer to the "Hazards and Public Safety" subsection above. Analysis determined that project-related truck trips would not increase hazards to school traffic because truck trips would be spread throughout the day and there are not any bus stops located along the truck routes. In addition, the analysis concluded there is the potential for the project to create a traffic hazard resulting from heavy trucks and farm machinery using certain roadways at the same time. Condition of Certification **TRANS-1** is being recommended which would require the applicant to prepare traffic control plan that addresses the safe operation of heavy trucks and farm machinery on the same roadway.
>
> Drivers on project-related haul routes for construction- and project-related traffic have the potential to experience Tule fog. Please refer to the "Hazards and Public Safety" subsection above. Analysis determined that safe operation of vehicles and trucks is regulated by the California Vehicle Code (sections 24400 through 24411 and 22350). Compliance of drivers with regulations of the California Vehicle Code would ensure safe operation and would not create a traffic hazard associated with Tule fog.

Regarding project-related vehicles competing with flocks of walking sheep, vehicles associated with implementation of the proposed project would be required to comply with all California vehicle code regulations. In addition, the California vehicle code provides for warning lights on vehicles herding livestock (Section 25270.5). The livestock owner would have responsibility to provide adequate warning to travelers on a public roadway.

Comment: Chris Romanini states if rail brings in coal then roads will continue to be clogged with vehicles related to employees, coke trucks, waste removal, and fertilizer business.

Response: The proposed HECA project is being analyzed for its potential environmental impacts associated with operating a rail spur under Alternative 1. Recommended conditions of certification would continue to apply to whichever project alternative is implemented by the applicant. Condition of Certification **TRANS-1** is being recommended which would require the applicant to prepare traffic control plan that addresses the safe operation of heavy trucks and farm machinery on the same roadway. Condition of Certification **TRANS-3** is being recommended to reduce impacts which would require the project owner to conduct a pavement test and based on test results to redesign and repave roadways used by project-related traffic. In addition, Condition of Certification **TRANS-4** is being recommended which would require the project owner to provide ongoing road repairs as needed.

Comment: Chris Romanini asks who will enforce the project owner to using a specific transportation route.

Response: The proposed HECA project acknowledges the need for roadway improvements (i.e., signalization of the current 4-way-stop SR 43 /Stockdale Highway intersection; signalization of the current 2-way-stop SR 119/Tupman Road intersection; construct a separate left-turn lane on the westbound approach of Stockdale Highway and construct a separate right-turn lane on the northbound approach of Dairy Road at the Dairy Road/Stockdale Highway intersection; reconstruct the Dairy Road/Adohr Road intersection to accommodate the turning radius needed by large trucks). The project applicant also states as part of the AFC (page 5.10-20) that the project owner will limit vehicular traffic to designated access roads.

BENJAMIN MCFARLAND, KERN COUNTY FARM BUREAU (TN 66242)

July 12, 2012

Comment: Benjamin McFarland states the project would impact agriculture through bifurcation of local farming activities as a result of new rail lines and disruption of neighboring farming activities.

Response: The HECA project could disrupt local farming activities with a proposed rail spur which would block access along private roads. As shown in **Traffic and Transportation Figure 1-3**, the HECA project would involve construction of rail safety devices at private at-grade crossings including warning devices and concrete roadway surfaces at six locations along the rail spur.

Construction of these private at-grade rail crossings would allow for east-west access along private roads and allow farming activities to continue undisrupted. However, staff is concerned that the number of crossings proposed could result in increased risks from the rail spur and has requested additional information from the applicant to evaluate this issue.

TOM FRANTZ, ASSOCIATION OF IRRITATED RESIDENTS (TN 66342)

July 27, 2012

Comment: Tom Frantz states the project must choose which option to use either a railroad spur or trucks for delivery of coal from the depot in Wasco.

> **Response:** The proposed HECA project is being analyzed for its potential environmental impacts associated with operating a rail spur under Alternative 1 and operating without a rail spur under Alternative 2.

ANTON GARABETIAN, CALIFONRIA PUBLIC UTILITIES COMMISSION (TN 68923)

December 13, 2012

Comment: Anton Garabetian acknowledges previous information provided by Energy Commission staff related to the proposed rail spur as part of the HECA project. Anton identifies the CPUC's role and process for reviewing and approving rail crossings.

> **Response:** Energy Commission staff desires to coordinate with the CPUC regarding their assistance with permit issuance and compliance review for the proposed rail spur.

SIERRA CLUB (TN 66429, 67239)

August 2, 2012 and September 21, 2012

Comment: Sierra Club requests more information on the practical and theoretical capacity of the existing rail corridors that would be used for transportation of the project's raw materials and products.

> **Response:** As identified by the applicant, implementation of the project with the rail spur under Alternative 1, the project would generate two trains in both directions per week on average (URS 2012c). Staff reviewed a study related to train operations of the SJVR in Fresno County. This study identified that as of January 2011 approximately 4,550 train trips per year occur on the SJVR in Fresno County exclusively. In addition, the same study identified a future potential of 9,649 train trips per year on the SJVR (FCOG 2011). Assuming the number of train trips would be similar in Kern County, project-related train trips would account for less than 5 percent of the total current train trips and less than 3 percent of the future potential train trips occurring on the SJVR.

Comment: Sierra Club requested more information regarding whether the additional train cars would result in constraints to the passenger rail system or adversely affect the transportation of freight in California and/or New Mexico.

> **Response:** One Amtrak passenger train currently operates per day in both directions on the Burlington Santa Fe (BNSF) route between Los Angeles and

Chicago (Amtrak 2013, URS 2012c). Train traffic generated by the HECA project would use a portion of the same route west of New Mexico. In most sections of this rail line, the route is double-tracked and train dispatching is conducted through centralized traffic control. Although the number of trains operating along this route is unknown, this route is considered a main artery and the project's low volume of trains would not affect the overall train operations on this route.

Comment: Sierra Club requested more information regarding whether the rail system would require improvements to the existing rail corridors.

Response: As identified by the applicant, the project would upgrade an existing 7-mile length of SJVR track between Bakersfield and the proposed rail spur (URS 2012c).

RICHARD AND JAN WOLFE (TN 66386)

July 30, 2012

Comment: Richard and Jan Wolfe identify themselves as living very close to the proposed coal plant and express concern with excessive traffic (additional 300+ trucks daily, 24 hours per day) and road damage. The commenter asks who will be responsible for repairing the roads from the increased heavy traffic caused by trucks.

Response: Daily truck volumes would increase with the implementation of the proposed HECA project under the no rail spur option. Analysis of the increased truck volumes concluded that with the addition of the HECA project's peak operation traffic, all study area roadway segments would continue to operate at an acceptable level of service. The analysis also concluded implementation of the proposed project would substantially increase traffic on certain roadway segments as compared to future Year 2017 without project conditions. Please refer to the "Operational Impacts and Mitigation" subsection above. Condition of Certification **TRANS-3** is being recommended to reduce impacts which would require the project owner to conduct a pavement test and based on test results to redesign and repave roadways used by project-related traffic. In addition, Condition of Certification **TRANS-4** is being recommended which would require the project owner to provide ongoing road repairs as needed.

Comment: The commenter states 300+ trucks per day hauling material to and from the plant will drastically change their way of life and states they do not need more traffic driving on front of their home.

Response: Daily truck volumes would increase with the implementation of the proposed HECA project under the rail spur option. Analysis of the increased truck volumes concluded that with the addition of the HECA project's peak operation traffic, all study area roadway segments would continue to operate at an acceptable level of service. The analysis also concluded implementation of the proposed project would substantially increase traffic on certain roadway segments as compared to future Year 2017 without project conditions. Please refer to the "Operational Impacts and Mitigation" subsection above. Condition of Certification **TRANS-3** is being recommended to reduce impacts which would require the project owner to conduct a pavement test and based on test results to redesign and repave roadways used by project-related traffic. In addition, Condition of Certification **TRANS-4** is being recommended which would require the project owner to provide ongoing road repairs as needed.

TRUDY DOUGLASS (TN 66389)

July 30, 2012

Comment: Judy Douglass identifies the local roads carry school buses and slow farm machinery.

Response: Project-related haul routes for construction- and project-related traffic are currently utilized by school buses and farm equipment. Please refer to the “Hazards and Public Safety” subsection above. Analysis determined that project-related truck trips would not increase hazards to school traffic because truck trips would be spread throughout the day and there are not any bus stops located along the truck routes. In addition, the analysis concluded there is the potential for the project to create a traffic hazard resulting from heavy trucks and farm machinery using certain roadways at the same time. Condition of Certification **TRANS-1** is being recommended which would require the applicant to prepare traffic control plan that addresses the safe operation of heavy trucks and farm machinery on the same roadway.

Comment: The commenter states the proposed project would result in 1,100 vehicles per day which would result in broken and demolished roadways. The commenter states the applicant should pay for building new roads.

Response: Daily truck volumes would increase with the implementation of the proposed HECA project. Analysis of the increased truck volumes concluded that with the addition of the HECA project’s peak operation traffic, all study area roadway segments would continue to operate at an acceptable level of service. The analysis also concluded implementation of the proposed project would substantially increase traffic on certain roadway segments as compared to future Year 2017 without project conditions. Please refer to the “Operational Impacts and Mitigation” subsection above. Condition of Certification **TRANS-3** is being recommended to reduce impacts which would require the project owner to conduct a pavement test and based on test results to redesign and repave roadways used by project-related traffic. In addition, Condition of Certification **TRANS-4** is being recommended which would require the project owner to provide ongoing road repairs as needed.

Comment: The commenter identifies the potential for Tule fog in the project area.

Response: Drivers on project-related haul routes for construction- and project-related traffic have the potential to experience Tule fog. Please refer to the “Hazards and Public Safety” subsection above. Analysis determined that safe operation of vehicles and trucks is regulated by the California Vehicle Code (sections 24400 through 24411 and 22350). Compliance of drivers with regulations of the California Vehicle Code would ensure safe operation and would not create a traffic hazard associated with Tule fog.

SAM ACKERMAN (TN 66543)

August 10, 2012

Comment: Sam Ackerman identifies concern by people with additional traffic from the proposed project causing wear and tear on roads. The commenter identifies local roadways are highly used by agricultural and oil operations. The commenter identifies the applicant plans to fund improvements to local roadways.

> **Response:** Daily truck volumes would increase with the implementation of the proposed HECA project. Analysis of the increased truck volumes concluded that with the addition of the HECA project's peak operation traffic, all study area roadway segments would continue to operate at an acceptable level of service. The analysis also concluded implementation of the proposed project would substantially increase traffic on certain roadway segments as compared to future Year 2017 without project conditions. Please refer to the "Operational Impacts and Mitigation" subsection above. Condition of Certification **TRANS-3** is being recommended to reduce impacts which would require the project owner to conduct a pavement test and based on test results to redesign and repave roadways used by project-related traffic. In addition, Condition of Certification **TRANS-4** is being recommended which would require the project owner to provide ongoing road repairs as needed.

EMAIL (TN 66497)

August 3, 2012

Comment: The commenter states the proposed project will have more truck traffic on narrow county roads.

> **Response:** Daily truck volumes would increase with the implementation of the proposed HECA project. Analysis of the increased truck volumes concluded that with the addition of the HECA project's peak operation traffic, all study area roadway segments would continue to operate at an acceptable level of service. The analysis also concluded implementation of the proposed project would substantially increase traffic on certain roadway segments as compared to future Year 2017 without project conditions. Please refer to the "Operational Impacts and Mitigation" subsection above. Condition of Certification **TRANS-3** is being recommended to reduce impacts which would require the project owner to conduct a pavement test and based on test results to redesign and repave roadways used by project-related traffic. In addition, Condition of Certification **TRANS-4** is being recommended which would require the project owner to provide ongoing road repairs as needed.

Kendell Hech (TN 66496)

August 3, 2012

Comment: The commenter expresses a general fear of potential traffic impacts from the project.

> **Response:** Daily truck volumes would increase with the implementation of the proposed HECA project. Analysis of the increased truck volumes concluded that with the addition of the HECA project's peak operation traffic, all study area

roadway segments would continue to operate at an acceptable level of service. The analysis also concluded implementation of the proposed project would substantially increase traffic on certain roadway segments as compared to future Year 2017 without project conditions. Please refer to the "Operational Impacts and Mitigation" subsection above. Condition of Certification **TRANS-3** is being recommended to reduce impacts which would require the project owner to conduct a pavement test and based on test results to redesign and repave roadways used by project-related traffic. In addition, Condition of Certification **TRANS-4** is being recommended which would require the project owner to provide ongoing road repairs as needed.

Letter (TN 66382)

July 30, 2012

Comment: The commenter identifies a huge increase in heavy-duty trucks on small country roads. The commenter asks who will manage the road surface.

Response: Daily truck volumes would increase with the implementation of the proposed HECA project. Analysis of the increased truck volumes concluded that with the addition of the HECA project's peak operation traffic, all study area roadway segments would continue to operate at an acceptable level of service. The analysis also concluded implementation of the proposed project would substantially increase traffic on certain roadway segments as compared to future Year 2017 without project conditions. Please refer to the "Operational Impacts and Mitigation" subsection above. Condition of Certification **TRANS-3** is being recommended to reduce impacts which would require the project owner to conduct a pavement test and based on test results to redesign and repave roadways used by project-related traffic. In addition, Condition of Certification **TRANS-4** is being recommended which would require the project owner to provide ongoing road repairs as needed.

Comment: The commenter asks what background checks will be conducted on truck drivers.

Response: The California Vehicle Code regulates the safe operation of vehicles, including heavy trucks. Please refer to "Compliance with Laws, Ordinances, Regulations, and Standards" subsection earlier in this document for more information. Although the project would not conduct specific background checks of truck drivers, law enforcement would be responsible for ensuring truck drivers are licensed and operating vehicles safely in accordance with the California Vehicle Code (Division 6, Chapter 7, Article 5, Section 15250).

Comment: The commenter asks how closely truck drivers will be monitored.

Response: As discussed above, the California Vehicle Code regulates the safe operation of vehicles, including heavy trucks. Please refer to "Compliance with Laws, Ordinances, Regulations, and Standards" subsection earlier in this document for more information. Although the project would not specifically monitor truck drivers, law enforcement would be responsible for ensuring truck drivers are operating vehicles safely in accordance with the California Vehicle Code.

Comment: The commenter expresses concern with trains potentially blocking Stockdale Highway or cutting through pistachio fields and other crops. The commenter requests that the public comment period be kept open for a reasonable amount of time after the rail route is announced.

Response: The project site is designed to allow for an entire train to be located completely onsite, and remain onsite, during offloading of coal and, thereby, prevent blocking nearby roadways. Specifically, the HECA site incorporates two loops for the rail line, one loop inside the other, located on the eastern third of the project site. In total, the HECA project site provides approximately 33,700 feet (6.4 miles) of rail line completely onsite for parking during the process of offloading the coal.

SIERRA CLUB (TN 66370)

July 27, 2012

Comment: Sierra Club states the Energy Commission must consider impacts from the flow of large trucks hauling supplies and materials during construction and operation.

Response: Daily truck volumes would increase with the implementation of the proposed HECA project. Analysis of the increased truck volumes concluded that with the addition of the HECA project's peak operation traffic, all study area roadway segments would continue to operate at an acceptable level of service. The analysis also concluded implementation of the proposed project would substantially increase traffic on certain roadway segments as compared to future Year 2017 without project conditions. Please refer to the "Direct/Indirect Impacts and Mitigation" subsection above. Condition of Certification **TRANS-3** is being recommended to reduce impacts which would require the project owner to conduct a pavement test and based on test results to redesign and repave roadways used by project-related traffic. In addition, Condition of Certification **TRANS-4** is being recommended which would require the project owner to provide ongoing road repairs as needed.

Comment: Sierra Club states the Energy Commission should consider impacts to emergency response vehicles and school buses that share the roads with large trucks.

Response: Project-related haul routes for construction- and project-related traffic are currently utilized by school buses and emergency response vehicles. Analysis determined that project-related truck trips would not increase hazards to school traffic because truck trips would be spread throughout the day and there are not any bus stops located along the truck routes.

In addition, the analysis identified in the event of an emergency at the HECA project site during construction, emergency vehicles would likely use either Dairy Road or Tupman Road and existing driveways to access the project site. Condition of Certification **TRANS-1** is being recommended which would require the applicant to prepare traffic control plan that addresses the assurance of access and movement of emergency vehicles.

BRAD BITTLESTON (TN 66348)

July 26, 2012

Comment: Brad Bittleston states the busy trucks would affect the enjoyment provided in their paradise since the 1960s. The commenter states that 1,000 trucks passing in front of his home every day should not be labeled as clean.

> **Response:** Daily truck volumes would increase with the implementation of the proposed HECA project. Analysis of the increased truck volumes concluded that with the addition of the HECA project's peak operation traffic, all study area roadway segments would continue to operate at an acceptable level of service. The analysis also concluded implementation of the proposed project would substantially increase traffic on certain roadway segments as compared to future Year 2017 without project conditions. Please refer to the "Direct/Indirect Impacts and Mitigation" subsection above. Condition of Certification **TRANS-3** is being recommended to reduce impacts which would require the project owner to conduct a pavement test and based on test results to redesign and repave roadways used by project-related traffic. In addition, Condition of Certification **TRANS-4** is being recommended which would require the project owner to provide ongoing road repairs as needed.

LORELEI OVIATT, KERN COUNTY PLANNING AND COMMUNITY DEVELOPMENT DEPARTMENT (TN 66243)

July 16, 2012

Comment: Lorelei Oviatt states Kern County wants to have further discussions regarding the structural capacity of specific haul routes that would be used by trucks, regarding the operational capacity of haul routes with respect to preliminary recommendations in the AFC for intersection signalization and other road improvements, regarding temporary impacts to existing roads resulting from construction traffic, and regarding the rail spur alignment and type of roadway crossings that would be implemented.

> **Response:** The Energy Commission desires to coordinate with Kern County regarding road design capacities for proposed truck haul routes, regarding needed road improvements, regarding potential impacts to roads, and regarding the proposed rail spur.

JERRY EZELL, SHAFTER-WASCO IRRIGATION DISTRICT (TN 69925)

March 14, 2013

Comment: Jerry Ezell expresses interest in receiving information regarding the transportation route for moving coal from off load to the project site.

> **Response:** Without the rail spur under Alternative 2, coal would be hauled by truck from Wasco to the project site via State Route 43 south to Stockdale Highway west, then to Morris Road south, and lastly to Station Road west. Maps depicting the route were also provided by the applicant in Figures A63-1 and A63-2 of the *Responses to CEC Data Requests – Nos. A1 through A123* (TN 66876).

HECA NEIGHBIORS AND FARMERS (TN 69773)

March 1, 2013

Comment: HECA neighbors and farmers express concern with dust smothering and retarding plant production.

> **Response:** Truck traffic generated by the project without the rail spur under Alternative 2 would transport coal in trailers. The California vehicle code requires vehicles to be driven such as to prevent any contents or load from dropping, sifting, leaking, spilling, or otherwise escaping from the vehicle (Section 23114(a)). In addition, the vehicle code requires vehicles transporting aggregate material upon a highway (e.g., SR 43) to cover the material (Section 23114(e)(1)). The project's compliance with state regulations would prevent coal dust from escaping truck trailers and, thereby, prevent the potential for coal dust smothering and retarding plant production.

JACQUELYN KITCHEN, KERN COUNTY PLANNING AND COMMUNITY DEVELOPMENT DEPARTMENT (TN 69831)

March 6, 2013

Comment: The Kern County Roads Department states there is not sufficient information available to make specific, detailed recommendations regarding traffic impacts. In addition, the Kern County Roads Department states the AFC does not address impacts to roadway segments related to the capacity of the road to accommodate heavy vehicles. The Kern County Roads Department has preliminarily concluded that Dairy Road, Adohr Road, Station Road, and Morris Road will not be able to withstand impacts thereby requiring reconstruction of those roadways.

> **Response:** Daily truck volumes would increase with the implementation of the proposed HECA project. Analysis of the increased truck volumes concluded that with the addition of the HECA project's peak operation traffic, all study area roadway segments would continue to operate at an acceptable level of service. The analysis also concluded implementation of the proposed project would substantially increase traffic on certain roadway segments as compared to future Year 2017 without project conditions. Please refer to the "Direct/Indirect Impacts and Mitigation" subsection above. Condition of Certification **TRANS-3** is being recommended to reduce impacts which would require the project owner to conduct a pavement test and based on test results to redesign and repave roadways used by project-related traffic. In addition, Condition of Certification **TRANS-4** is being recommended which would require the project owner to provide ongoing road repairs as needed.

CONCLUSIONS AND RECOMMENDATIONS

Staff has analyzed the proposed HECA project's impacts to the nearby traffic and transportation system. Staff recommends implementation of the proposed conditions of certification (**TRANS-1** through **TRANS-10)** to reduce potentially significant impacts associated with the proposed HECA project and for the proposed project to comply with all applicable LORS related to traffic and transportation. However, there are outstanding issues for the proposed project which are not able to be analyzed as part of this

PSA/DEIS. These outstanding issues are discussed below. Staff is unable to reach a conclusion until outstanding information is provided.

OUTSTANDING INFORMATION REQUIRED FOR COMPLETION OF THE FSA/FEIS

The applicant recently identified in their proposal to add storage of limestone and ammonium nitrate at the project site. These revisions would change the number of truck trips to and from the project site. Staff needs additional information from the applicant regarding how this revision in the number of truck trips could also change the potential impacts related to traffic and transportation. Specifically, staff requests the applicant provide revised truck trip numbers for both with the rail spur and without the rail spur and identify changes to the LOS at intersections and roadway segments that would occur with the revised truck trips. This issue will be addressed in the Final Staff Assessment (FSA).

Along with the revision to the on- site storage of limestone and ammonia nitrate used for the HECA project, staff has raised a question regarding the need to expand the Wasco coal servicing facility to serve the project's demand. Potential components of the coal servicing facility initially considered by staff include the possible need for additional storage silos and/or receiving lane for trains and/or haul trucks. Staff requests the applicant identify specific components that would need to be expanded at the coal servicing facility in Wasco. The project's potential demand for expanding the Wasco coal servicing facility will be addressed in the FSA.

Under a proposed alternative, HECA would construct and operate a rail spur for delivery of fuel and products to and from the project site. Because the CPUC traditionally has jurisdiction over such facilities, staff will continue to coordinate closely with the CPUC to ensure appropriate design of the rail line for safe operation. In order to ensure that CPUC staff has sufficient information in order to assist in analyzing the proposal, the applicant must submit all the information otherwise required for a formal application pursuant to Title 20, California Code of Regulations, section 3.1 for all public at-grade rail crossings needed for the proposed rail spur. This information is outlined in the CPUC Rules of Practice and Procedure 3.7 to 3.11 under Section 1001 of the Public Utilities Code and should be submitted, to both the CPUC and Energy Commission staff. Additionally, the applicant must provide an analysis discussing the need for each of the private at-grade crossings proposed, the potential risks involved in proposing this many private crossings in such a small area, and whether, upon further examination, any crossings can be eliminated. This analysis should also discuss potential impacts to the movement of farm machinery and equipment due to reducing the crossings, and should identify to what extent lands on either side of the proposed spur are owned and maintained by the same person or entity, and, thus, could possibly be impacted by reduced connectivity.

Although potentially significant impacts associated with implementation of the proposed HECA project can be mitigated to a less-than-significant level, staff has concerns that the project has the potential to substantially increase traffic levels on farming roads not currently intended for heavy truck traffic and heavy load capacities. This substantial increase in traffic also has the potential to impact traffic associated with existing farming activities (e.g., tractors traveling on public roadway) thereby potentially resulting in safety issues and increased accidents to the public. Based on a recent Board of Supervisor's meeting held on February 26, 2013, the Board instructed the Public Works Department to review the roadways intended for heavy truck, and worker traffic and report back at their June 2013 Board meeting as to recommendations for improvements to the local roadway system. Staff will address the concerns and/or recommendations by Kern County in the FSA.

PROPOSED CONDITIONS OF CERTIFICATION

TRANS-1 The project owner shall consult with the Kern County Roads Department and prepare and submit to the Energy Commission Compliance Project Manager (CPM) for approval a construction traffic control plan (TCP) and implementation program. The project owner shall submit the proposed TCP to the Caltrans District 6 office and to the affected local jurisdictions in sufficient time for review and comment, and to the CPM for review and approval prior to the proposed start of construction and implementation of the plan. The traffic control plan must address the following:

- Provisions for redirection of construction traffic with a flag person as necessary to ensure traffic safety and minimize interruptions to non-construction related traffic flow;
- Placement of necessary signage, lighting, and traffic control devices at the project construction site and lay-down areas;
- A heavy-haul plan addressing the transport and delivery of heavy and oversized loads requiring permits from the California Department of Transportation (Caltrans), other state or federal agencies, and/or the affected local jurisdictions;
- Location and details of construction along affected roadways at night, where permitted;
- Temporary closure of travel lanes or disruptions to street segments and intersections during construction activities;
- Traffic diversion plans (in coordination with Kern County, Caltrans) to ensure access during temporary lane/road closures;
- Access to residential and/or commercial property located near construction work and truck traffic routes;
- Ensure access for emergency vehicles to the project site;
- Advance notification to residents, businesses, emergency providers, hospitals, and school districts that would be affected when roads may be partially or completely closed;
- Provisions that allow for the safe operation of heavy trucks and farm machinery on the same roadway;
- Identification of safety procedures for exiting and entering the site access

gate; and

- Obtain all required and necessary encroachment permits from the Kern County Roads Department.

Verification: At least 60 calendar days prior to the start of construction, the project owner shall submit the TCP to the applicable agencies for review and comment and to the CPM for review and approval. The project owner shall also provide the CPM with a copy of the transmittal letter to the agencies requesting review and comment and a copy of the encroachment permit issued by the affected agency for any activities on a public road.

At least 30 calendar days prior to the start of construction, the project owner shall provide copies of any comment letters received from the agencies, along with any changes to the proposed development plan, to the CPM for review and approval.

TRANS-2 The project owner shall construct intersection improvements needed to support construction and operational traffic so that intersections will operate at an acceptable LOS and/or will operate with reduced risk for accidents, including:

- Intersection of SR 43 and Stockdale Highway: signalization of the current 4-way-stop intersection.
- Intersection of SR 119 and Tupman Road: signalization of the current 2-way-stop intersection.
- Intersection of Dairy Road and Stockdale Highway: construct a separate left-turn lane on the westbound approach of Stockdale Highway, and a separate right-turn lane on the northbound approach of Dairy Road. Reconstruct to a three-way-stop intersection with flashing lights.
- Intersection of Dairy Road and Adohr Road: reconstruct the intersection to accommodate the turning radius needed by large trucks to make required turns. Reconstruct to a four-way-stop intersection with flashing lights.
- Intersection of Morris Road and Stockdale Highway: construct a separate left-turn lane on the westbound approach of Stockdale Highway, and a separate right-turn lane on the northbound approach of Morris Road. Reconstruct to a three-way-stop intersection with flashing lights.
- Intersection of Station Road and Tupman Road: reconstruct to a three-way-stop intersection with flashing lights.

The project owner shall construct intersection improvements needed to support operational traffic, with no rail spur, so that intersections will operate with reduced risk for accidents, including:

- Intersection of J Street/H Street (in City of Wasco): reconstruct to a three-way-stop intersection.
- Intersection of 9th Street/H Street (in City of Wasco): reconstruct to a three-way-stop intersection.
- Intersection of 9th Street/J Street (in City of Wasco): reconstruct to a three-way-stop intersection.

Verification: At least 30 days prior to site mobilization, the project owner shall provide to the CPM photographic evidence and coordination documents with Kern County Roads Department (e.g., approved drawings, encroachment permits) that these intersection improvements have been completed and are fully functional.

TRANS-3 The project owner shall conduct a pavement test of Adohr Road, Dairy Road, Morris Road, Station Road, J Street (in City of Wasco), H Street (in City of Wasco), and 9th Street (in City of Wasco) that would be utilized for project-related construction and operation activities.

Based on results of the pavement test, prior to the start of construction, the project owner shall redesign and repave Adohr Road, Dairy Road, Morris Road, Station Road, J Street, H Street, and/or 9th Street as reasonably necessary to accommodate project-related construction activities that meet the minimum Caltrans standard for a roadway that accommodates heavy trucks.

If Adohr Road, Dairy Road, Morris Road, Station Road, J Street, H Street, and/or 9th Street are identified by the project owner or the affected jurisdiction as needing redesign and/or pavement replacement, the project owner shall notify the CPM and the affected jurisdiction(s) to identify the section of the public right-of-way to be redesigned and/or repaved to Caltrans standards. At that time, the project owner shall establish a schedule for completion and approval of the redesigning and/or repaving.

Verification: Prior to the start of site mobilization, the project owner shall provide a copy of the pavement test to the CPM for review. Sixty (60) days prior to the start of the construction, the project owner shall establish a schedule for completion and approval of the redesigning and/or repaving. Following completion of any public right-of-way redesigning and/or pavement replacement, the project owner shall provide documentation of any public right-of-way redesigning and/or pavement replacement to Kern County for review and comment, and to the CPM for review and approval.

TRANS-4 The project owner shall coordinate with Kern County to restore all public roads, easements, and rights-of-way that have been damaged due to project-related construction and operation activities. Restoration of significant damage which could cause hazards (such as potholes or deterioration of the pavement edges, damaged signage) must take place within two days after the damage has occurred. The restoration shall be completed to the road's original condition in compliance with the applicable jurisdiction's specifications.

If damage to public roads, easements, or rights-of-way is identified by the project owner or the affected jurisdiction, the project owner shall notify the CPM within five days and the affected jurisdiction(s) to identify the section of the public right-of-way to be repaired. At that time, the project owner shall establish a schedule for completion and approval of the repairs. Following completion of any public right-of-way repairs, the project owner shall provide the CPM letters signed by the person authorized to accept the repairs in the affected jurisdiction(s) stating their satisfaction with the repairs.

Verification: Prior to the start of site mobilization, the project owner shall photograph or videotape all of the affected public roads, easements, right-of-way segment(s), and/or intersections. The project owner shall notify affected jurisdictions that the project intends to start construction activities. The project owner shall provide the photograph or videotape to the CPM and the affected jurisdictions (California Department of Transportation (Caltrans) and Kern County). The purpose of this notification is to request that these jurisdictions consider postponement of any planned public right-of-way repair or improvement activities in areas affected by project construction until construction is completed, and to coordinate any concurrent construction-related activities that cannot be postponed.

TRANS-5 The project owner shall obtain the necessary permits and/or licenses from theCalifornia Highway Patrol, Caltrans District 6, and any relevant local jurisdictions for the transportation of hazardous materials. The project owner shall ensure compliance with all applicable regulations and implementation of the proper procedures. In addition, the owner shall ensure that hazardous materials deliveries occur outside of normal commute hours.

Verification: In the Monthly Compliance Reports (MCRs), the owner shall provide copies of all permits/licenses obtained for the transportation of hazardous substances.

At least 30 calendar days prior to the start of construction, the project owner shall provide copies of any comment letters received from the agencies, along with any changes to the proposed development plan, to the CPM for review and approval.

TRANS-6 The project owner shall comply with Caltrans, Kern County Roads Department, and other relevant jurisdictions' limitations on vehicle sizes, weights, and travel routes. In addition, the project owner shall obtain all necessary transportation permits from Caltrans, Kern County, and other relevant jurisdictions for roadway use.

Verification: In the Monthly Compliance Reports, the project owner shall submit copies of any permits received during that reporting period. In addition, the project owner shall retain copies of these permits and supporting documentation in its compliance file for at least six months after the start of commercial operation.

TRANS-7 The project owner shall ensure that all temporary and permanent HECA project components over 200-feet in height shall have lighting and marking consistent with FAA Advisory circular 70/7460-1 K Change 2, Obstruction Marking and Lighting, red lights - Chapters 4, 5(Red), & 12 so as not to create a hazard to air navigation.

Verification: The project owner shall submit FAA Form 7460-2, Notice of Actual Construction or Alteration, to the FAA at least 10 days prior to start of construction (7460-2, Part I) and again within 5 days after the construction reaches its greatest height (7460-2, Part II). A copy of these completed forms shall also be provided to the CPM. Furthermore, at least 30 days prior to start of project operation, the Project Owner shall provide to the CPM pictures of any HECA project components over 200-feet in height with all FAA required lighting and marking installed.

TRANS-8 Prior to start-up and testing activities of the plant and all related facilities, the project owner shall through the FAA notify all pilots using the Elk Hills-Buttonwillow Airport and airspace above HECA site of potential air hazards. These activities would include, but not be limited to, the project owner through the FAA issuing a notice to airmen (NOTAM) of the identified air hazard and updating the Terminal Area Chart and all other FAA-approved airspace charts used by pilots that include the HECA site to indicate that pilots should avoid overflight below 730 feet AGL. The project owner shall work with Elk Hills-Buttonwillow Airport to modify the Airport Facility Directory (AFD) to show the location of the HECA site on a map or figure and put in a remark about thermal plumes could cause moderate to severe turbulence, and therefore, pilots should avoid direct overflight below 730 feet.

Verification: At least 60 days prior to start of project operation, the project owner shall submit to the CPM for review copies of requests to the FAA and Elk Hills-Buttonwillow Airport requesting the incorporation of the project into the NOTAM, Terminal Area Chart, and Airport Facility Directory and any subsequent correspondence with these organizations.

TRANS-9 Prior to start-up and testing activities, the project owner shall notify the Kern County Agricultural Commissioners that due to the potential presence of project thermal plumes with significant size and velocities, crop dusting aircraft should avoid direct overflight of the HECA site.

Verification: At least 60 days prior to start-up and testing activities, the project owner shall provide the CPM with a copy of letters advising the Kern County Agricultural Commissioners that crop dusting aircraft should avoid direct overflight of the HECA site.

TRANS-10 The project owner shall include power line marking balls on the 230 kV transmission line interconnect between the HECA site and PG&E Midway

Substation along any segments adjacent to agricultural land uses utilizing crop dusting aircraft activities.

Verification: Prior to start of commercial operation, the project owner shall provide to the CPM pictures of HECA project transmission line demonstrating that installation of marking balls has been completed.

RECOMMENDED MITIGATION MEASURES

To minimize impacts from EOR construction related trips, staff recommends Kern County adopt the following mitigation to ensure that construction traffic impacts from the OEHI CO_2 EOR facility are less than significant:

OEHI TRANS-1 The project owner shall consult with the Kern County Roads Department and prepare and a construction traffic control plan (TCP) and implementation program. The project owner shall submit the proposed TCP to the Caltrans District 6 office and to the affected local jurisdictions in sufficient time for review and comment, and to the Kern County CPM for review and approval prior to the proposed start of construction and implementation of the plan. The traffic control plan must address the following:

- Provisions for redirection of construction traffic with a flag person as necessary to ensure traffic safety and minimize interruptions to non-construction related traffic flow;
- Placement of necessary signage, lighting, and traffic control devices at the project construction site and lay-down areas;
- A heavy-haul plan addressing the transport and delivery of heavy and oversized loads requiring permits from the California Department of Transportation (Caltrans), other state or federal agencies, and/or the affected local jurisdictions;
- Location and details of construction along affected roadways at night, where permitted;
- Temporary closure of travel lanes or disruptions to street segments and intersections during construction activities;
- Traffic diversion plans (in coordination with Kern County, Caltrans) to ensure access during temporary lane/road closures;
- Access to residential and/or commercial property located near construction work and truck traffic routes;
- Ensure access for emergency vehicles to the project site;
- Advance notification to residents, businesses, emergency providers, hospitals, and school districts that would be affected when roads may be partially or completely closed;
- Provisions that allow for the safe operation of heavy trucks and farm machinery on the same roadway;
- Identification of safety procedures for exiting and entering the site access gate; and
- Obtain all required and necessary encroachment permits from the Kern County Roads Department.

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APPENDIX TT-1: PLUME VELOCITY ANALYSIS

Joseph Hughes and William Walters

INTRODUCTION

The following provides assessment of vertical plume velocities for the Hydrogen Energy California (HECA) power plant project's cooling towers, gas turbine/heat recovery generator (HRSG), coal dryer, and gasification flare exhaust stack plumes. Staff completed calculations to determine the worst-case vertical plume velocities at different heights above the stacks based on the applicant's proposed facility design and expected operations.

PROJECT DESCRIPTION

The proposed project includes three large cooling towers, one MHI 501GAC combustion turbine-generator (CTG)/HRSG exhaust, a coal dryer exhaust, and a gasification flare. There are a few other proposed exhaust sources, including a couple of small flares, a CO_2 vent, an auxiliary boiler, and two emergency engines; however, staff analysis of these other exhaust sources found that these stacks have vertical plume velocity potentials that are well below 4.3 meters per second, which is the staff threshold of concern at 500 feet above ground level. Therefore, these sources are not discussed further in this analysis. This project is designed as a base load facility that would operate year round.

PLUME VELOCITY CALCULATION METHOD

Staff has selected a calculation approach from a technical paper (Best 2003) to estimate the worst-case plume vertical velocities for the HECA exhausts. The calculation approach, which is also known as the "Spillane approach", used by staff is limited to calm wind conditions, which are the worst-case wind conditions. The Spillane approach uses the following equations to determine vertical velocity for single stacks during dead calm wind (i.e. wind speed = 0) conditions:

(1) $(V*a)^3 = (V*a)_o^3 + 0.12*F_o*[(z-z_v)^2-(6.25D-z_v)^2]$

(2) $(V*a)_o = V_{exit}*D/2*(T_a/T_s)^{0.5}$

(3) $F_o = g*V_{exit}*D^2*(1-T_a/T_s)/4$

(4) $Z_v = 6.25D*[1-(T_a/T_s)^{0.5}]$

Where: V = vertical velocity (m/s), plume-average velocity
a = plume top-hat radius (m, increases at a linear rate of $a = 0.16*(z- z_v)$
F_o= initial stack buoyancy flux m^4/s^3
z = height above ground (m)
z_v= virtual source height (m)
V_{exit}= initial stack velocity (m/s)

D = stack diameter (m)
T_a= ambient temperature (K)
T_s= stack temperature (K)
g = acceleration of gravity (9.8 m/s^2)

Equation (1) is solved for V at any given height above ground that is above the momentum rise stage for single stacks (where z > 6.25D) and at the end of the plume merged stage for multiple plumes. This solution provides the plume-average velocity for the area of the plume at a given height above ground; the peak plume velocity would be two times higher than the plume-average velocity predicted by this equation. As can be seen the stack buoyancy flux (F_o) is a prominent part of Equation (1). The calm condition calculation basis clearly represents the worst-case conditions, and the vertical velocity will decrease substantially as wind speed increases from calm conditions.

For multiple stack plumes, where the stacks are equivalent, the multiple stack plume velocity during calm winds was calculated by staff in a simplified fashion, presented in the Best Paper as follows:

(5) $V_m = V_{sp} * N^{0.25}$

Where: V_m = multiple stack combined plume vertical velocity (m/s)
V_{sp} = single plume vertical velocity (m/s), calculated using Equation (1)
N = number of stacks

Staff notes that this simplified multiple stack plume velocity calculation method predicts somewhat lower velocity values than the full Spillane approach methodology as given in data results presented in the Best paper (Best 2003). However, the use of this approach on long linear cooling towers such as the power block and process cooling towers designed for the HECA project will likely over predict the combined plume velocities. To partially address this, although the process and power block cooling towers are aligned linearly to form a 25-cell cooling tower, staff has not combined the stacks for the adjacent power block and process cooling towers for the velocity analysis, and instead modeled them separately. Regardless, staff describes the plume dimensions below and points out that at 400 feet no more than 4 cells would overlap.

VERTICAL PLUME VELOCITY ANALYSIS

COOLING TOWERS DESIGN AND OPERATING PARAMETERS

The design and operating parameter data for the project’s three cooling towers are provided in **Plume Velocity Tables 1-3**.

Plume Velocity Table 1
ASU Cooling Tower Operating and Exhaust Parameters

Parameter		Cooling Tower Design Parameters		
Number of Cells per Tower		4 Cells (1 by 4 Linear Design)		
Cell Height		16.76 meters (55 feet)		
Cell Stack Diameter		9.14 meters (30 feet)		
Tower Housing Length		60.70 meters (199 feet)		
Tower Housing Width		18.29 meters (60 feet)		
Case	**Inlet Air Ambient Condition**	**Heat Rejection Rate (MW/hr)**	**Exhaust Flow Rate (klbs/hr)**	**Exhaust Temperature (°F)**
3 Cells	39°F, 82% RH	89.8	14,922	84
4 Cells	65°F, 55% RH	90.8	20,052	75
4 Cells	97°F, 20% RH	90.6	19,741	71

Source: HECA 2012e, Section 5.11, Table 5.11-9

Plume Velocity Table 2
13-Cell Process Cooling Tower Operating and Exhaust Parameters

Parameter		Cooling Tower Design Parameters		
Number of Cells per Tower		13 Cells (1 by 13 Linear Design)		
Cell Height		16.76 meters (55 feet)		
Cell Stack Diameter		9.14 meters (30 feet)		
Tower Housing Length		198 meters (650 feet)		
Tower Housing Width		18.29 meters (60 feet)		
Case	**Inlet Air Ambient Condition**	**Heat Rejection Rate (MW/hr)**	**Exhaust Flow Rate (klbs/hr)**	**Exhaust Temperature (°F)**
10 Cells	39°F, 82% RH	292	48,497	71
13 Cells	65°F, 55% RH	293.7	65,129	75
13 Cells	97°F, 20% RH	294.5	64,197	84

Source: HECA 2012e, Section 5.11, Table 5.11-8

Plume Velocity Table 3
12-Cell Power Block Cooling Tower Operating and Exhaust Parameters

Parameter		**Cooling Tower Design Parameters**		
Number of Cells per Tower		12 Cells (1 by 12 Linear Design)		
Cell Height		16.76 meters (55 feet)		
Cell Stack Diameter		9.14 meters (30 feet)		
Tower Housing Length		183 meters (600 feet)		
Tower Housing Width		18.29 meters (60 feet)		
Inlet Air Ambient Condition	No. Cells in Operation	Heat Rejection Rate (MW/hr)	Exhaust Flow Rate (klbs/hr)	Exhaust Temperature (°F)
Hydrogen Rich Fuel with No Duct Firing				
39°F, 82% RH	9	248.1	45,077	70
65°F, 55% RH	12	253.8	60,310	74
97°F, 20% RH	12	260.9	59,223	83
Hydrogen Rich Fuel with Duct Firing				
39°F, 82% RH	9	269.5	44,767	71
65°F, 55% RH	12	271.1	60,155	75
97°F, 20% RH	12	271.8	59,223	84
Natural Gas with No Duct Firing				
39°F, 82% RH	9	--	--	--
65°F, 55% RH	12	--	--	--
97°F, 20% RH	12	149	81.4	81.4
Natural Gas with Duct Firing				
39°F, 82% RH	9	--	--	--
65°F, 55% RH	12	--	--	--
97°F, 20% RH	12	195.3	85.1	85.1

Source: HECA 2012e, Section 5.11, Table 5.11-7

For the worst-case analysis for these three plume sources, the 65°F ambient condition exhaust case was selected to determine the worst case exhaust velocity conditions. Additionally, for the power block cooling tower the hydrogen rich fuel with no duct firing operating case was selected. This ambient condition was selected because lower temperature cases would have large visible plumes that pilots would be able to see and avoid. Also, during colder conditions cooling tower cells would begin to shutdown decreasing flow rates and vertical velocities.

GAS TURBINE/HRSG DESIGN AND OPERATING PARAMETERS

The design and operating parameter data for the gas turbine/HRSG stack exhaust are provided in **Plume Velocity Table 4**.

Plume Velocity Table 4
Gas Turbine/HRSG Exhaust Parameters

Parameter	HRSG/Coal Drying Full Load Stack Exhaust Parameters					
Stack Height	213 feet (65 meters)					
Stack Diameter	23 feet (7 meters)					
Ambient Conditions	Moisture Content (% by weight)		Exhaust Flow Rate (klbs/hr)		Exhaust Temp (°F)	
Hydrogen Rich Fuel						
	Duct Firing	No Duct Firing	Duct Firing	No Duct Firing	Duct Firing	No Duct Firing
39°F	7.2	6.4	4,876	3,956	200	200
65°F	7.8	7.0	4,712	3,747	200	200
97°F	8.3	7.5	4,575	3,496	200	200

Source: HECA 2012e, Section 5.11, Table 5.11-6

For the worst-case analysis for this plume source, the 65°F ambient condition for the hydrogen rich fuel with duct firing operating case was selected to determine the worst-case velocity conditions. This operating case was selected because the use of hydrogen rich fuel should be the most frequent operating case and duct firing increases exhaust flow rates. Natural gas fuel operation should occur infrequently and has reduced vertical velocity potential relative to hydrogen rick fuel due to lower exhaust temperatures. Staff modeled the 39°F ambient condition without duct firing and determined worst case velocities did not exceed the results for 65°F with duct firing.

COAL DRYER DESIGN AND OPERATING PARAMETERS

The design and operating parameter data for the gas turbine/HRSG stack exhaust are provided in **Plume Velocity Table 5**.

Plume Velocity Table 5
Coal Dryer Exhaust Parameters

Parameter	HRSG/Coal Drying Full Load Stack Exhaust Parameters		
Stack Height	305 feet (92.96 meters)		
Stack Diameter	16 feet (4.88 meters)		
Ambient Conditions	Moisture Content (% by weight)	Exhaust Flow Rate (klbs/hr)	Exhaust Temp (°F)
39°F	10.8	800	200
65°F	10.8	800	200
97°F	10.8	800	200

Source: HECA 2012e, Section 5.11, Table 5.11-6

For the worst-case analysis for this plume source, the 39°F ambient condition case was selected to determine the worst-case velocity conditions because exhaust parameters are constant. Therefore, the colder ambient conditions would contribute to higher plume velocities.

GASIFICATION FLARE DESIGN AND OPERATING PARAMETERS

The design and operating parameter data for the gasification flare stack exhaust are provided in **Plume Velocity Table 6**.

Plume Velocity Table 6
Gasification Flare Exhaust Parameters

Ambient Case	Gasification Flare 65°F
Stack Height	250 feet (76.2 meters)
Stack Diameter	9.8 feet (2.99 meters)
Stack Velocity	65.5 ft/sec (20 m/s)
Exhaust Temperature	1,832°F (1,273°K)

Source: HECA 2012e, Appendix E-3, Flare Stack Parameters

For the worst-case analysis for this plume source, the 65°F ambient condition was selected for this intermittent emission source. The plume velocity is dominated by the high exhaust temperatures from the flare so an average annual ambient condition was used for the modeling.

PLUME VELOCITY CALCULATION RESULTS

Using the Spillane calculation approach, the plume average vertical velocity at different heights above ground was determined by staff for calm conditions. Staff's calculated plume average velocity values are provided in **Plume Velocity Table 7.** The combined cooling tower cell velocities are calculated by combining adjacent cells per Equation 5. For conservatism the values provided below assume that all cells within each cooling tower have completely merged. However, it is important to note that at 300 feet and 400 feet the plume diameters are approximately 24 meters and 34 meters respectively. This means that no more than 3 and 4 cooling tower cell plumes would overlap at 300 feet and 400 feet respectively, which would reduce plume velocities to levels similar to the ASU cooling tower.

Plume Velocity Table 7
HECA Exhaust Sources Worst-Case Predicted Plume Velocities (m/s)

	ASU Cooling Tower	Power Block Cooling Tower	Process Cooling Tower	Gas Turbine/HRSG	Coal Dryer	Gasification Flare
Height (ft)	**65°F**	**65°F**	**65°F**	**65°F**	**39°F**	**65°F**
300	4.55	5.99	6.11	[a]	[a]	[a]
400	3.57	4.70	4.80	6.80	[a]	6.49
500	3.06	4.03	4.11	5.47	3.32	5.30
600	2.75	3.61	3.69	4.81	2.98	4.67
700	2.53	3.33	3.40	4.40	2.72	4.26
800	2.37	3.12	3.18	4.10	2.53	3.97
900	2.24	2.95	3.01	3.88	2.38	3.74
1,000	2.14	2.82	2.88	3.69	2.26	3.56
1,100	2.06	2.71	2.76	3.54	2.16	3.41
1,200	1.99	2.62	2.67	3.41	2.08	3.28
1,300	1.93	2.53	2.59	3.30	2.01	3.17
1,400	1.87	2.46	2.51	3.20	1.94	3.07

1,500	1.82	2.40	2.45	3.11	1.89	2.99
1,600	1.78	2.34	2.39	3.03	1.84	2.91
1,700	1.74	2.29	2.33	2.96	1.79	2.84
1,800	1.70	2.24	2.29	2.90	1.75	2.77
1,900	1.67	2.20	2.24	2.84	1.71	2.72
2,000	1.64	2.16	2.20	2.78	1.68	2.66

Source: Staff calculations.
Note:
[a] – Plume velocities within the jet phase of the plume (within 6.25 diameters above the stack height) cannot be accurately determined using the calculation method employed by staff.

As explained in the Traffic and Transportation section, a plume average vertical velocity of 4.3 m/s has been determined by staff to be the critical velocity of concern to light aircraft. As shown in **Plume Velocity Table** 7, the cooling tower exhausts at 500 feet above ground are estimated to be 3.06 meters per second (m/s) for the ASU, 4.03 m/s for the gasification block and 4.11 m/s for the power block; each is below this threshold of concern. However, results for the gas turbine/HRSG and gasification flare exceed this threshold.

The gas turbine/HRSG plume average velocity is calculated to drop below 4.3 m/s at a height of approximately 730 feet. This is a worst-case value that assumes full load operation during cold ambient temperatures with dead calm wind conditions from ground level to 730 feet above the ground. For other operating scenarios and higher ambient temperatures the top height for the 4.3 m/s velocities would be somewhat lower than this maximum value.

The gasification flare plume average velocity is calculated to drop below 4.3 m/s at a height of approximately 690 feet. This is a worst-case value that assumes worst case operation during annual average ambient temperatures with dead calm wind conditions from ground level to 690 feet above the ground. The predicted plume velocities would be marginally higher for lower ambient temperature conditions.

The velocity values listed above in **Plume Velocity Table 7** are plume average velocities across the area of the plume. The maximum plume velocity, based on a normal Gaussian distribution, is two times the plume average velocities shown in the table.

WIND SPEED STATISTICS

Plume Velocity Table 8 provides the hourly average wind speed statistics for Bakersfield from meteorological data collected and processed by the SJVAPCD for 2005 through 2008. Calm winds for the purposes of the reported monitoring station statistics are those hours with average wind speeds below a threshold wind velocity, which is generally less than 2 to 3 knots (approximately 1 to 1.5 m/s). Calm or very low wind speeds can also occur for shorter periods of time within each of the monitored average hourly conditions.

Plume Velocity Table 8
Wind Speed Statistics for Bakersfield
(2005 through 2008)

Wind Speed Statistics	
Wind Speed	Percent
Calm	23.6%
≤ 1.5 m/s	35.8%
≤ 2.1 m/s	42.7%
≤ 2.6 m/s	51.7%

Source: Staff data reduction of SJVAPCD Bakersfield meteorological data from 2005-2008.

Calm/low wind speeds conditions averaging an hour or longer appear to be a frequent wind condition in the site area.

CONCLUSIONS

The calculated worst case calm wind condition vertical plume average velocities from the HECA cooling towers are not predicted to exceed 4.3 m/s at heights at or above 500 feet above ground level, except in cases where there would be large visible plumes for the power block cooling tower. The calculated worst case calm wind condition vertical plume average velocity for the HECA coal dryer is not predicted to exceed 4.3 m/s at heights at or above 500 feet above ground level. However, the calculated worst case calm wind condition vertical plume average velocities from the HECA gas turbine/HRSG and gasification flare are predicted to exceed 4.3 m/s at heights at or above 500 feet above ground level. Specifically, for the gas turbine/HRSG, this critical threshold is expected to be exceeded up to 730 feet above ground level and for the gasification flare, the critical threshold is expected to be exceeded up to 690 feet above ground level. There are a number of other plume sources at the site which would not have plume average velocities above 4.3 m/s at heights of concern, but these sources would add to the overall air turbulence that would be experienced above the HECA project site.

The vertical velocity from the equipment exhaust at a given height above the stack decreases as wind speed increases. However, the plume average vertical velocities for the gas turbine/HRSG and gasification flare will remain relatively high, and would exceed 4.3 m/s above 500 feet about ground level, during calm or very low wind speed conditions. These low wind speed conditions lasting an hour or more occur reasonably frequently at the site location. Additionally, shorter periods of dead calm winds, lasting long enough to increase the vertical plume average velocity height up to its peak height, can occur even more often during hours with low average wind speeds.

The reader should refer to the **Traffic and Transportation** Section for a discussion of impacts to aviation.

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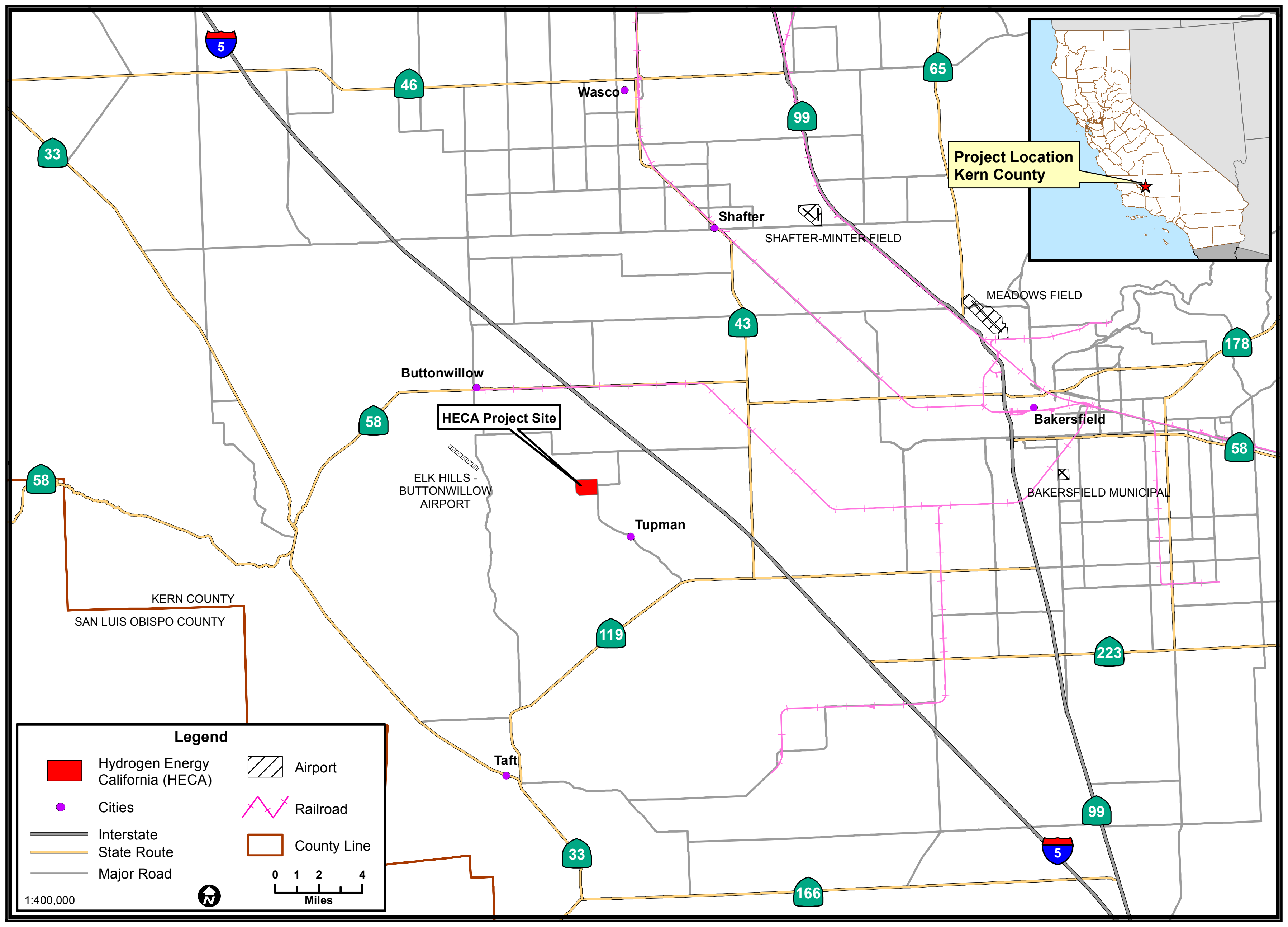
TRAFFIC AND TRANSPORTATION - FIGURE 1

Hydrogen Energy California (HECA) Project - Regional Transportation Setting

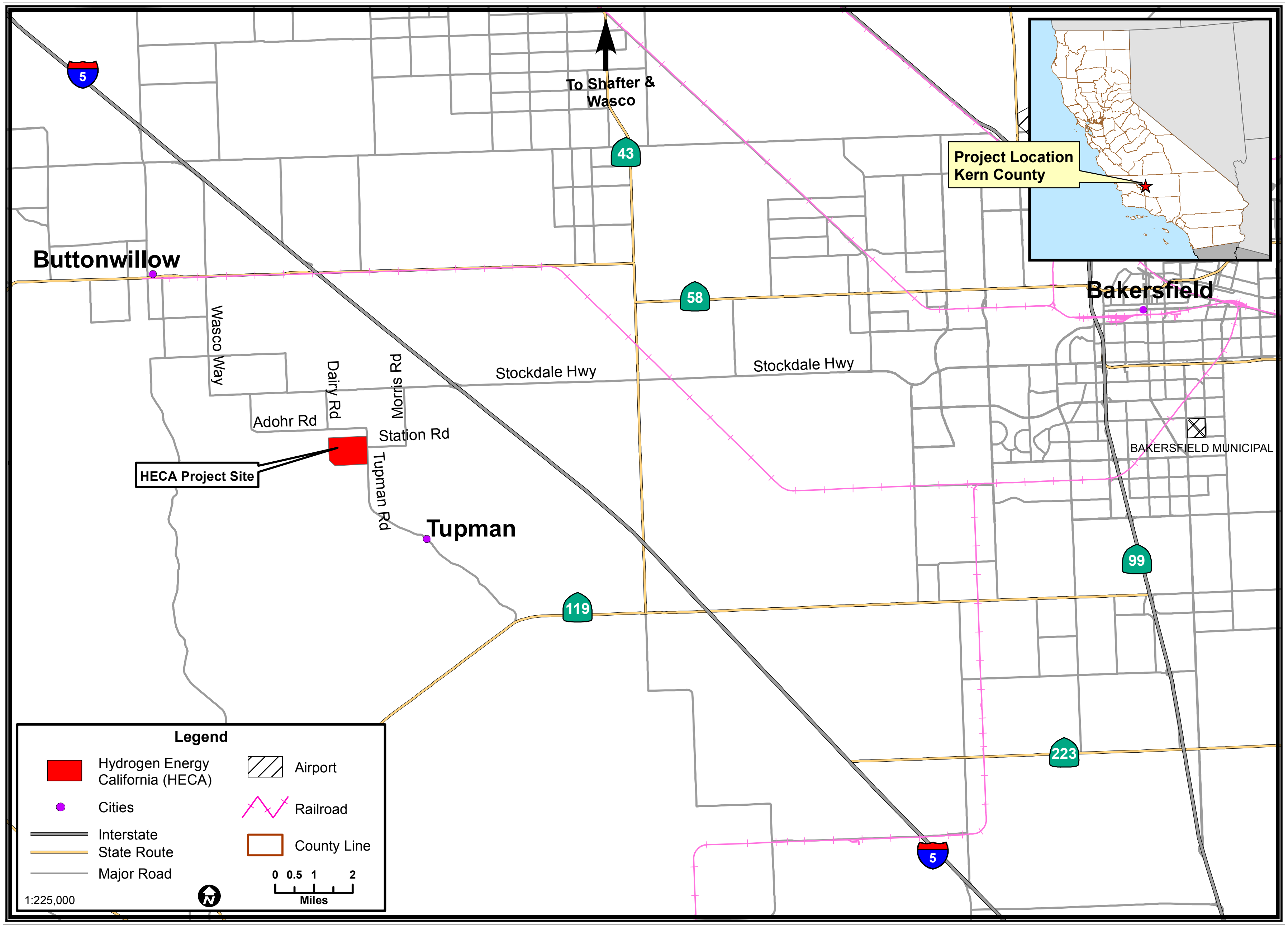


CALIFORNIA ENERGY COMMISSION, SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: California Energy Commission, URS, Inc and Multinet

TRAFFIC AND TRANSPORTATION - FIGURE 2

Hydrogen Energy California (HECA) Project - Local Transportation Network

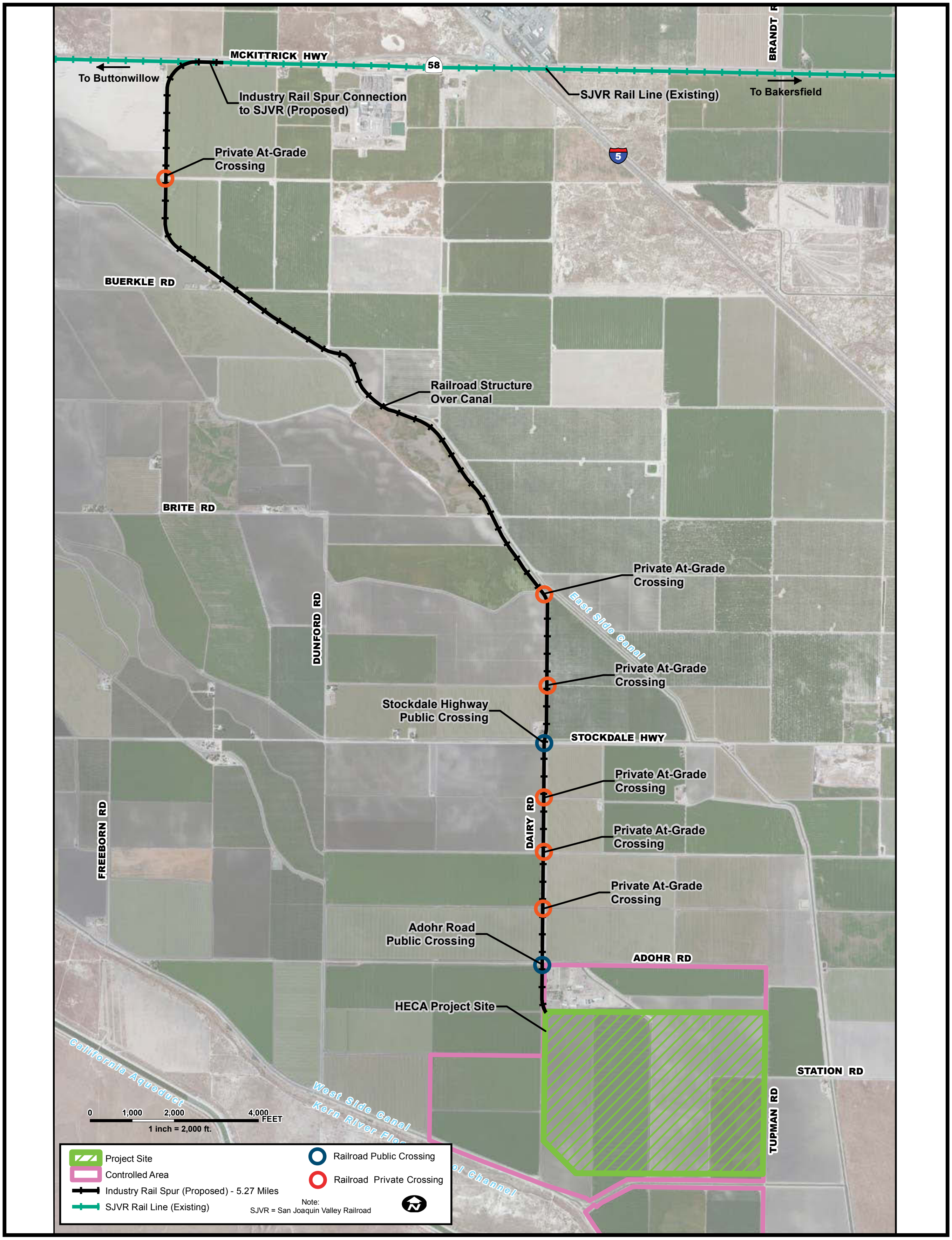


CALIFORNIA ENERGY COMMISSION, SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: California Energy Commission, URS, Inc and Multinet

TRAFFIC AND TRANSPORTATION - FIGURE 3

Hydrogen Energy California (HECA) - Proposed Railroad Crossings near the HECA Project Site



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: HECA, Personal Communication April 5, 2013

TRANSMISSION LINE SAFETY AND NUISANCE

Obed Odoemelam, Ph.D.

SUMMARY OF CONCLUSIONS

The applicant, Hydrogen Energy California, LLC, proposes to transmit power from the proposed Hydrogen Energy California project to Pacific Gas and Electric's 230-kV Midway Substation via the existing Midway-Wheeler Ridge transmission line and a new 230-kV PG&E switching station approximately 2 miles east of the project site. The proposed tie-in line would be a single-circuit 230-kV line. The applicant also proposes to use the same 230-kV line structures to support another 230-kV single-circuit line to import power into the project's on-site Air Separation Unit from the PG&E power grid. Since the 230-kV line to be used would be operated within the PG&E service area, it would be designed, constructed, operated, routed, and maintained according to PG&E's guidelines for line safety and field management which conform to applicable laws, ordinances, regulations and standards. The proposed route would traverse a mostly agricultural area with no nearby residents thereby eliminating the potential for residential electric and magnetic field exposures which have been of some health concern in recent years. With the four proposed conditions of certification, any safety and nuisance impacts from construction and operation of the proposed line would be less than significant along the route for the general population or an identified environmental justice population.

INTRODUCTION

The purpose of this staff analysis is to assess the transmission line design and operational plan for the proposed Hydrogen Energy California (HECA) project to determine whether its related field and non-field impacts would constitute a significant environmental hazard in the area around the proposed route. All related health and safety laws, ordinances, regulations, and standards (LORS) are currently aimed at minimizing such hazards. Staff's analysis focuses on the following issues taking into account both the physical presence of the line and the physical interactions of its electric and magnetic fields:

- aviation safety;
- interference with radio-frequency communication;
- audible noise;
- fire hazards;
- hazardous shocks;
- nuisance shocks; and
- electric and magnetic field (EMF) exposure.

METHODOLOGY AND THRESHOLDS FOR DETERMINING ENVIRONMENTAL CONSEQUENCES

The potential magnitude of the field and non-field impacts of concern in this staff analysis depends on compliance with the listed design-related LORS and industry practices. These LORS and practices have been established to maintain impacts below levels of potential environmental significance. Thus, if staff determines that the project would comply with applicable LORS, we would conclude that any transmission line-related safety and nuisance impacts would be less than significant. The nature of these individual impacts is discussed below together with the potential for compliance with the LORS that apply.

Laws, Ordinances, Regulations, and Standards

The federal, state, and local laws and policies in the next section apply to the control of the field and non-field impacts of electric power lines. Staff's analysis examines the project's compliance with these requirements.

Transmission Line Safety and Nuisance (TLSN) Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable LORS	Description
Aviation Safety	
Federal	
Title 14, Part 77 of the Code of Federal Regulations (CFR),"Objects Affecting the Navigable Air Space"	Describes the criteria used to determine the need for a Federal Aviation Administration (FAA) "Notice of Proposed Construction or Alteration" in cases of potential obstruction hazards.
FAA Advisory Circular No. 70/7460-1G, "Proposed Construction and/or Alteration of Objects that May Affect the Navigation Space"	Addresses the need to file the "Notice of Proposed Construction or Alteration" (Form 7640) with the FAA in cases of potential for an obstruction hazard.
FAA Advisory Circular 70/7460-1G, "Obstruction Marking and Lighting"	Describes the FAA standards for marking and lighting objects that may pose a navigation hazard as established using the criteria in Title 14, Part 77 of the CFR.
Interference with Radio Frequency Communication	
Federal	
Title 47, CFR, section 15.2524, Federal Communications Commission (FCC)	Prohibits operation of devices that can interfere with radio-frequency communication.
State	
California Public Utilities Commission (CPUC) General Order 52 (GO-52)	Governs the construction and operation of power and communications lines to prevent or mitigate interference.
Audible Noise	
Local	
Kern County General Plan: Noise Element	References the county's Ordinance Code for noise limits.

Applicable LORS	Description
Kern County: Noise Ordinance	Establishes performance standards for planned residential or other noise-sensitive land uses.
Hazardous and Nuisance Shocks	
State	
CPUC GO-95, “Rules for Overhead Electric Line Construction”	Governs clearance requirements to prevent hazardous shocks, grounding techniques to minimize nuisance shocks, and maintenance and inspection requirements.
Title 8, California Code of Regulations (CCR) section 2700 et seq. “High Voltage Safety Orders”	Specifies requirements and minimum standards for safely installing, operating, working around, and maintaining electrical installations and equipment.
National Electrical Safety Code	Specifies grounding procedures to limit nuisance shocks. Also specifies minimum conductor ground clearances.
Industry Standards	
Institute of Electrical and Electronics Engineers (IEEE) 1119, “IEEE Guide for Fence Safety Clearances in Electric-Supply Stations”	Specifies the guidelines for grounding-related practices within the right-of-way and substations.
Electric and Magnetic Fields	
State	
GO-131-D, CPUC ”Rules for Planning and Construction of Electric Generation Line and Substation Facilities in California”	Specifies application and noticing requirements for new line construction including EMF reduction.
CPUC Decision 93-11-013	Specifies CPUC requirements for reducing power frequency electric and magnetic fields.
Industry Standards	
American National Standards Institute (ANSI/IEEE) 644-1944 Standard Procedures for Measurement of Power Frequency Electric and Magnetic Fields from AC Power Lines	Specifies standard procedures for measuring electric and magnetic fields from an operating electric line.
Fire Hazards	
State	
14 CCR sections 1250-1258, “Fire Prevention Standards for Electric Utilities”	Provides specific exemptions from electric pole and tower firebreak and conductor clearance standards and specifies when and where standards apply.

SETTING AND EXISTING CONDITIONS

As discussed by the applicant, Hydrogen Energy International, LLC, (HECA), the proposed project (HECA) would be located on a 453-acre land parcel approximately 1.5 miles northwest of the unincorporated community of Tupman in unincorporated Kern County. The line is proposed to be placed on one side of the tower structure to connect the project’s on-site switchyard and a new 230-kV PG&E switching station approximately 2 miles east of the project site. Connection to this new PG&E switching station line would allow for the looping connection to PG&E’s Midway Substation via the existing Midway-Wheeler Ridge lines. The other side of the same 230-kV line structure would be used to import energy from the PG&E power grid to the proposed project's on-site Air Separation Unit (ASU) which would be under separate ownership and located at the project site where it would obtain its own power directly from the PG&E power grid.

The project and its proposed tie-in line would be in an area primarily used for agricultural activities with the nearest residence approximately 1,400 feet away (HECA 2012e pp. 5.6-3 and 5.4-5) meaning that there would not be the type of residential field exposure that has been of health concern in recent years.

PROJECT DESCRIPTION

The proposed tie-in line would consist of the following individual segments:

- A new, 230-kV overhead transmission line consisting of two individual circuits on each side to connect the new 230-kV PG&E switching station 2 miles to the east while also connecting the on-site ASU to the PG&E power grid; and
- The project's on-site 230-kV switchyard from which the conductors would extend to their respective connecting points on the PG&E power system.

The proposed project line would have a 100-foot right-of-way within the proposed route. The interconnection point with the new PG&E switching station would be at the Olean Avenue and Elk Valley intersection, which was chosen to minimize the length of the line necessary for the related connection to the PG&E grid while maximizing the distance to areas of habitation (HECA 1202e pp. 4-1 and 4-5).

The line's conductors would be aluminum conductor, steel-reinforced cables located on single shaft galvanized tubular steel towers or steel poles as typical of similar PG&E lines. The applicant provided the details of the proposed support structures as related to line safety, maintainability, and field reduction efficiency. Fifteen support structures would be used for the off-site segment and 11 additional support structures would be used for the on-site segment. The support structures would be spaced 700 feet apart with a minimum ground clearance of 40 feet which is significantly more than the CPUC-specified minimum of 30 feet (HECA 2012e, pp.4-1, 4-2, and 4-8, and Figures 4-2 and 4-3).

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

DIRECT IMPACTS AND MITIGATION

Aviation Safety

Any potential hazard to area aircraft would relate to the potential for collision in the navigable airspace. The requirements in the LORS listed on **TLSN Table 1** establish the standards for assessing the potential for obstruction hazards within the navigable space and establish the criteria for determining when to notify the FAA about such hazards. These regulations require FAA notification in cases of structures over 200 feet from the ground, or if the structure were to be less than 200 feet in height but located within the restricted airspace in the approaches to public or military airports. For airports with runways longer than 3,200 feet, the restricted space is defined by the FAA as an area extending 20,000 feet from the runway. For airports with runways of 3,200 feet or less, the restricted airspace would be an area that extends 10,000 feet from this runway. For heliports, the restricted space is an area that extends 5,000 feet.

Buttonwillow Airport is located approximately 3.5 miles southwest of the connected Midway Substation potentially placing the proposed line's structures within the restricted airspace. However, to pose an aviation hazard according to FAA criteria, the line structure would have to be 160 feet in height or more and 3 miles away. At a maximum of 115-feet in height and 3.5 miles away, the erected line would not pose any aviation hazard within the proposed route (HECA 2012e, p. 4-10). The other area airports are Ford City, Bakersfield and Gottlieb Airports. The Ford City Airport is located 14 miles south of Tupman; the Bakersfield Airport is located approximately 22 miles east of Tupman, with Gottlieb approximately 14 miles east of Buttonwillow. None of these airports is close enough for any transmission line-related collision hazards. Therefore, staff does not recommend a condition of certification regarding aviation safety.

Interference with Radio-Frequency Communication

Transmission line-related radio-frequency interference is one of the indirect effects of line operation and is produced by the physical interactions of line electric fields. Such interference is due to the radio noise produced by the action of the electric fields on the surface of the energized conductor. The process involved is known as *corona discharge*, but is referred to as *spark gap electric discharge* when it occurs within gaps between the conductor and insulators or metal fittings. When generated, such noise manifests itself as perceivable interference with radio or television signal reception or interference with other forms of radio communication. Since the level of interference depends on factors such as line voltage, distance from the line to the receiving device, orientation of the antenna, signal level, line configuration and weather conditions, maximum interference levels are not specified as design criteria for modern transmission lines. The level of any such interference usually depends on the magnitude of the electric fields involved and the distance from the line. The potential for such impacts is therefore minimized by reducing the line electric fields and locating the line away from inhabited areas.

The proposed project line would be built and maintained according to standard practices that minimize surface irregularities and discontinuities. Moreover, the potential for such corona-related interference is usually of concern for lines of 345 kV and greater, and not for 230-kV lines such as the proposed line. The proposed low-corona designs are used for PG&E lines of similar voltage rating to reduce surface electric field gradients and the related potential for corona effects. Since the proposed lines would traverse a largely uninhabited agricultural area, staff does not expect any corona-related radio-frequency interference or complaints and does not recommend any related condition of certification.

Audible Noise

The noise-reducing designs related to electric field intensity are not specifically mandated by federal or state regulations in terms of specific noise limits. As with radio noise, such audible noise is limited instead through design, construction, or maintenance practices established from industry research and experience as effective without significant impacts on line safety, efficiency, maintainability, and reliability. As with radio noise, audible noise usually results from the action of the electric field at the surface of the line conductor and could be perceived as a characteristic crackling, frying, or hissing sound or hum, especially in wet weather. Since the noise level depends on the strength of the line electric field, the potential for perception can be assessed from estimates of the field strengths expected during operation. Such noise is usually generated during rainfall, but mainly from overhead lines of 345 kV or greater. It is, therefore, not generally expected at significant levels from lines of less than 345 kV as proposed for HECA. Research by the Electric Power Research Institute (EPRI 1982) has validated this by showing the fair-weather audible noise from modern transmission lines to be generally indistinguishable from background noise at the edge of a right-of-way of 100 feet or more; the proposed line right-of-way would be 100 feet (HECA 2012e, p. 4-5). Since the low-corona designs are also aimed at minimizing field strengths, staff does not expect the proposed line operation to add significantly to current background noise levels in the project area. For an assessment of the noise from the proposed project and related facilities, please refer to staff's analysis in the **Noise and Vibration** section.

Fire Hazards

The fire hazards addressed through the related LORS in **TLSN Table 1** are those that could be caused by sparks from conductors of overhead lines, or that could result from direct contact between the line and nearby trees and other combustible objects.

Standard fire prevention and suppression measures for similar PG&E lines would be implemented for the proposed project line (HECA 2012e, p. 4-8). The applicant's intention to ensure compliance with the clearance-related aspects of GO-95 would be an important part of this mitigation approach. Condition of Certification **TLSN-3** is recommended to ensure compliance with important aspects of the fire prevention measures.

Hazardous Shocks

Hazardous shocks are those that could result from direct or indirect contact between an individual and the energized line, whether overhead or underground. Such shocks are capable of serious physiological harm or death and remain a driving force in the design and operation of transmission and other high-voltage lines.

No design-specific federal regulations have been established to prevent hazardous shocks from overhead power lines. Safety is assured within the industry from compliance with the requirements specifying the minimum national safe operating clearances applicable in areas where the line might be accessible to the public.

The applicant's stated intention to implement the GO-95-related measures against direct contact with the energized line (HECA 2012e, p.4-8) would serve to minimize the risk of hazardous shocks. Staff's recommended Condition of Certification **TLSN-1** would be adequate to ensure implementation of the necessary mitigation measures.

Nuisance Shocks

Nuisance shocks are caused by current flow at levels generally incapable of causing significant physiological harm. They result mostly from direct contact with metal objects electrically charged by fields from the energized line. Such electric charges are induced in different ways by the line's electric and magnetic fields.

There are no design-specific federal or state regulations to limit nuisance shocks in the transmission line environment. For modern overhead high-voltage lines, such shocks are effectively minimized through grounding procedures specified in the National Electrical Safety Code (NESC) and the joint guidelines of the American National Standards Institute (ANSI) and the Institute of Electrical and Electronics Engineers (IEEE). For the proposed project line, the project owner will be responsible in all cases for ensuring compliance with these grounding-related practices within the right-of-way.

The potential for nuisance shocks around the proposed line would be minimized through standard industry grounding practices (HECA 2012a, p. 4-7). Staff recommends Condition of Certification **TLSN-4** to ensure such grounding for HECA.

Electric and Magnetic Field Exposure

The possibility of deleterious health effects from electromagnetic field (EMF) exposure has increased public concern in recent years about living near high-voltage lines. Both electric and magnetic fields occur together whenever electricity flows, and exposure to them together is generally referred to as *EMF exposure*. The available evidence as evaluated by the California Public Utilities Commission (CPUC), other regulatory agencies, and staff has not established that such fields pose a significant health hazard to exposed humans. There are no health-based federal regulations or industry codes specifying environmental limits on the strengths of fields from power lines. Most regulatory agencies believe, as staff does, that health-based limits are inappropriate at this time. They also believe that the present knowledge of the issue does not justify any retrofit of existing lines.

Staff considers it important, as does the CPUC, to note that while such a hazard has not been established from the available evidence, the same evidence does not serve as proof of a definite lack of a hazard. Staff therefore considers it appropriate, in light of present uncertainty, to recommend feasible reduction of such fields without affecting safety, efficiency, reliability, and maintainability.

While there is considerable uncertainty about EMF health effects, the following facts have been established from the available information and have been used to establish existing policies:

- Any exposure-related health risk to the exposed individual will likely be small.
- The most biologically significant types of exposures have not been established.
- Most health concerns are about the magnetic field.
- There are measures that can be employed for field reduction, but they can affect line safety, reliability, efficiency, and maintainability, depending on the type and extent of such measures.

State's Approach to Regulating Field Exposures

In California, the CPUC (which regulates the installation and operation of many high-voltage lines owned and operated by investor-owned utilities) has determined that only no-cost or low-cost measures are presently justified in any effort to reduce power line fields beyond levels existing before the present health concern arose. The CPUC has further determined that such reduction should be made only in connection with new or modified lines. It requires each utility within its jurisdiction to establish EMF-reducing measures and incorporate such measures into the designs for all new or upgraded power lines and related facilities within their respective service areas. The CPUC further established specific limits on the resources to be used in each case for field reduction. Such limitations were intended by the CPUC to apply to the cost of any redesign to reduce field strength or relocation to reduce exposure. Publicly owned utilities, which are not within the jurisdiction of the CPUC, voluntarily comply with these CPUC requirements. This CPUC policy resulted from assessments made to implement CPUC Decision 93-11-013.

The CPUC has recently revisited the EMF management issue to assess the need for policy changes to reflect the available information on possible health impacts. The findings specified in Decision D.06-1-42 of January 2006, did not point to a need for significant changes to existing field management policies.

Since there are no residences in the immediate vicinity of the proposed project line, there would not be the long-term residential EMF exposures mostly responsible for the health concern of recent years. The only project-related EMF exposures of potential significance would be the short-term exposures of plant workers, regulatory inspectors, maintenance personnel, visitors, or individuals in the vicinity of the line. These types of exposures are short term and well understood as not significantly related to the health concern.

In keeping with this CPUC policy, staff requires a showing that each proposed overhead line would be designed according to the safety and EMF-reducing design guidelines applicable to the utility service area involved. These field-reducing measures can impact line operation if applied without appropriate regard for environmental and other local factors bearing on safety, reliability, efficiency, and maintainability. Therefore, it is up to each applicant to ensure that such measures are applied in ways that prevent significant impacts on line operation and safety. The extent of such applications would be reflected by ground-level field strengths as measured during operation. When estimated or measured for lines of similar voltage and current-carrying capacity, such field strength values can be used by staff and other regulatory agencies to assess the effectiveness of the applied reduction measures. These field strengths can be estimated for any given design using established procedures. Estimates are specified for a height of one meter above the ground, in units of kilovolts per meter (kV/m), for the electric field, and milligauss (mG) for the companion magnetic field. Their magnitude depends on line voltage (in the case of electric fields), the geometry of the support structures, degree of cancellation from nearby conductors, distance between conductors, and, in the case of magnetic fields, amount of current in the line.

Since the CPUC currently requires that most new lines in California be designed according to safety and the EMF-reducing guidelines of the electric utility in the service area involved, their fields are required under this CPUC policy to be similar to fields from similar lines in that service area. Designing the proposed project line according to existing PG&E field strength-reducing guidelines would constitute compliance with the CPUC requirements for line field management.

Industry's and Applicant's Approach to Reducing Field Exposures

The present focus is on the magnetic field because unlike electric fields, it can penetrate the soil, buildings, and other materials to produce the types of human exposures at the root of the health concern of recent years. The industry seeks to reduce exposure, not by setting specific exposure limits, but through design guidelines that minimize exposure in each given case. As one focuses on the strong magnetic fields from the more visible high-voltage power lines, staff considers it important, for perspective, to note that an individual in a home could be exposed to much stronger fields while using some common household appliances than from high-voltage lines (National Institute of Environmental Health Services and the U.S. Department of Energy, 1998). The difference between these types of field exposures is that the higher-level, appliance-related exposures are short term, while the exposures from power lines are lower level, but long term. Scientists have not established which of these types of exposures would be more biologically meaningful in the individual. Staff notes such exposure differences only to show that high-level magnetic field exposures regularly occur in areas other than around high-voltage power lines.

As with similar PG&E lines, specific field strength-reducing measures would be incorporated into the proposed line's design to ensure the field strength minimization currently required by the CPUC in light of the concern over EMF exposure and health.

The field reduction measures to be applied include the following:

1. increasing the distance between the conductors and the ground to an optimal level;
2. reducing the spacing between the conductors to an optimal level;
3. minimizing the current in the line; and
4. arranging current flow to maximize the cancellation effects from interacting of conductor fields.

Since the route of the proposed project line would have no nearby residences, the long-term residential field exposures at the root of the health concern of recent years would not be a significant concern. The field strengths of most significance in this regard would be as encountered at the edge of the line's 100-foot right-of-way. These field intensities would depend on the effectiveness of the applied field-reducing measures. The applicant calculated the maximum electric and magnetic field intensities expected when one or both of the two proposed line circuits are energized (HECA 2012a, pp. 4-7 through 4-13 through 4-15 and Figures 4-10 through 4-12). The maximum electric field strength was calculated as 0.46 kV/m at the edge of the 100-foot right-of-way while the maximum operational magnetic field strength was calculated as 22.2 mG. These field strength values are similar to those of similar PG&E lines (as required under current

CPUC regulations) but, in the case of the magnetic field, the estimate is much less than the 200 mG currently specified by the few states with regulatory limits. The requirements in Condition of Certification **TLSN-2** for field strength measurements are intended to assess the applicant's assumed field reduction efficiency.

CUMULATIVE IMPACTS

Operating any given project may lead to significant adverse cumulative impacts when its effects are considered cumulatively considerable. "Cumulatively considerable" means in this context that the incremental field and non-field effects of an individual project would be significant when considered together with the effects of past, existing, and future projects (California Code Regulation, Title 14, section 15130). When field intensities are measured or calculated for a specific location, they reflect the interactive, and therefore, cumulative effects of fields from all contributing conductors. This interaction could be additive or subtractive depending on prevailing conditions. Since the proposed project's transmission line would be designed, built, and operated according to applicable field-reducing PG&E guidelines (as currently required by the CPUC for effective field management), any contribution to cumulative area exposures should be at levels expected for PG&E lines of similar voltage and current-carrying capacity and not considered environmentally significant in the present health risk-based regulatory scheme. The actual field strengths and contribution levels for the proposed line design would be assessed from the results of the field strength measurements specified in Condition of Certification **TLSN-2**. Since there are no nearby area lines, no cumulative safety and nuisance impacts from the combined interaction of fields from nearby lines are expected.

COMPLIANCE WITH LORS

As previously noted, current health-risk-driven CPUC policy on EMF management requires that any high-voltage line within a given area be designed to incorporate the field strength-reducing guidelines of the main area utility lines to be interconnected. The utility in the case of HECA is PG&E. Since the proposed project's 230-kV line and related switchyards would be designed according to the respective requirements of the LORS listed in **TLSN Table 1**, and operated and maintained according to current PG&E guidelines on line safety and field strength management, staff considers the proposed design and operational plan to be in compliance with the health and safety requirements of concern in this analysis. The actual contribution to the area's field exposure levels would be assessed for the proposed route from results of the field strength measurements required in Condition of Certification **TLSN-2**.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

Staff received no public or agency comments on the transmission line nuisance and safety aspects of the proposed HECA.

NOTEWORTHY PUBLIC BENEFITS

Since the proposed tie-in line would pose specific, although insignificant risks of the field and nonfield effects of concern in this analysis, its building and operation would not yield any public benefits regarding the effort to minimize any human risks from these impacts.

FACILITY CLOSURE

If the proposed HECA were to be closed and decommissioned, and all related structures are removed as described in the **PROJECT DESCRIPTION** section, the minimal electric shocks and fire hazards from the physical presence of this tie-in line would be eliminated. Decommissioning and removal would also eliminate the line's field and non-field impacts assessed in this analysis in terms of aviation safety, interference with radio-frequency communication, audible noise, fire hazards, hazardous shocks, nuisance shocks and electric and magnetic field exposure. Since the line would be designed and operated according existing PG&E guidelines, these impacts would be as expected for PG&E lines of the same voltage and current-carrying capacity and therefore, at levels reflecting compliance with existing health and safety LORS.

DIRECT AND INDIRECT IMPACTS OF THE NO-ACTION ALTERNATIVE

Under the No-Action Alternative, DOE would not provide financial assistance to the Applicant for the HECA Project. The Applicant could still elect to construct and operate its project in the absence of financial assistance from DOE, but DOE believes this is unlikely. For the purposes of analysis in the PSA/DEIS, DOE assumes the project would not be constructed under the No-Action Alternative. Accordingly, the No-Action Alternative would have no impacts associated with this resource area.

CONCLUSIONS

Since staff does not expect the proposed 230-kV transmission tie-in line to pose an aviation hazard according to current FAA criteria, we do not consider it necessary to recommend specific location changes on the basis of a potential hazard to area aviation.

The potential for nuisance shocks would be minimized through grounding and other field-reducing measures that would be implemented in keeping with current PG&E guidelines (reflecting standard industry practices). These field-reducing measures would maintain the generated fields within levels not associated with radio-frequency interference or audible noise.

The potential for hazardous shocks would be minimized through compliance with the height and clearance requirements of CPUC's General Order 95. Compliance with Title 14, California Code of Regulations, section 1250, would minimize fire hazards while the use of low-corona line design, together with appropriate corona-minimizing construction practices, would minimize the potential for corona noise and its related interference with radio-frequency communication in the area around the route.

Since electric or magnetic field health effects have neither been established nor ruled out for the proposed HECA and similar transmission lines, the public health significance of any related field exposures cannot be characterized with certainty. The only conclusion to be reached with certainty is that the proposed line's design and operational plan would be adequate to ensure that the generated electric and magnetic fields are managed to an extent the CPUC considers appropriate in light of the available health effects information. The long-term, mostly residential, magnetic exposure of health concern in recent years would be insignificant for the proposed line given the absence of residences along the proposed route. On-site worker or public exposure would be short term and at levels expected for PG&E lines of similar design and current-carrying capacity. Such exposure is well understood and has not been established as posing a significant human health hazard.

Since the proposed project's line would be operated to minimize the health, safety, and nuisance impacts of concern to staff and would be routed through an area with no nearby residences, staff considers the proposed design, maintenance, and construction plan as complying with the applicable LORS. With implementation of the four recommended conditions of certification, any such impacts would be less than significant around the route for either the general population or any identified environmental justice population.

PROPOSED CONDITIONS OF CERTIFICATION

TLSN-1 The project owner shall construct the proposed 230-kV transmission line according to the requirements of California Public Utility Commission's GO-95, GO-52, GO-131-D, Title 8, and Group 2, High Voltage Electrical Safety Orders, sections 2700 through 2974 of the California Code of Regulations, and Pacific Gas and Electric's EMF reduction guidelines.

Verification: At least 30 days prior to start of construction of the transmission line or related structures and facilities, the project owner shall submit to the compliance project manager (CPM) a letter signed by a California registered electrical engineer affirming that the lines will be constructed according to the requirements stated in this condition.

TLSN-2 The project owner shall use a qualified individual to measure the strengths of the electric and magnetic fields from the line at the points of maximum intensity at the edge of the right-of-way as reflected in the estimates provided by the applicant. The measurements shall be made before and after energization according to the American National Standard Institute/Institute of Electrical and Electronic Engineers (ANSI/IEEE) standard procedures. The after measurement shall be completed no later than six months after the start of operations.

Verification: The project owner shall file copies of the pre-and post-energization measurements with the CPM within 60 days after completion of the measurements.

TLSN-3 The project owner shall ensure that the right-of-way for the proposed transmission line is kept free of combustible material, as required under the provisions of section 4292 of the Public Resources Code and section 1250 of Title 14 of the California Code of Regulations.

Verification: The project owner shall provide a summary of inspection results and any fire prevention activities carried out along the right-of-way and provide such summaries in the Annual Compliance Report on transmission line safety and nuisance-related requirements.

TLSN-4 The project owner shall ensure that all permanent metallic objects within the line right-of-way are grounded according to industry standards regardless of ownership.

Verification: At least 30 days before the lines are energized, the project owner shall transmit to the CPM a letter signed by a California registered electrical engineer confirming compliance with this condition.

REFERENCES

EPRI — Electric Power Research Institute 1982. Transmission Line Reference Book: 345 kV and Above.

HECA 2012e—SCS Energy California, LLC (tn 65049). Amended Revised Application for Certification for the Hydrogen Energy California HECA, Volumes I, II and III (o8-AFC-8A) dated 05/02/12. Submitted to the California Energy Commission on 05/02/2012.

National Institute of Environmental Health Services 1998. *An Assessment of the Health Effects from Exposure to Power-Line Frequency Electric and Magnetic Fields*. A Working Group Report. August 1998.

VISUAL RESOURCES

Elliott Lum

SUMMARY OF CONCLUSIONS

Energy Commission staff has analyzed the potential visual impacts of the proposed Hydrogen Energy California, LLC (HECA) project and its adjoining Occidental of Elk Hills, Inc. (OEHI) component in accordance with the National Environmental Policy Act (NEPA) and California Environmental Quality Act (CEQA). The two statutes are similar in their requirements concerning analysis of a project's impacts. Therefore, unless otherwise noted, staff's use of, and reference to, CEQA criteria and guidelines also encompasses and satisfies NEPA requirements for this environmental document.

Staff concludes that the proposed HECA project, after implementing all staff-recommended conditions of certification, would still have a significant and unavoidable adverse direct visual impact. Furthermore, the project would not be consistent with all applicable laws, ordinances, regulations, and standards (LORS).

Specifically, staff concludes that the HECA project would introduce a significant visual impact at Key Observation Point (KOP) 1 (HECA). KOP 1 is located on Station Road, approximately 2,600 feet east of the middle of the HECA project site.

The **Socioeconomics** section identifies an Environmental Justice community within the HECA sphere of influence. Staff has reviewed **Socioeconomics Figure 1** showing the environmental justice population is greater than 50 percent within a six-mile radius of the HECA project site. Additionally, a significant impact to visual resources has been identified at KOP 1 (HECA). However, the significant visual impact only affects one residence at KOP 1. Furthermore, the census block most likely affected by the visual impact[1] that contains said residence only contains a total of eight persons (including, two non-Hispanic white persons). Therefore, the relatively small environmental justice population within that radius (and even smaller in the affected census block) coupled with the fact that the visual impact affects only one residence at KOP 1, leads staff to the conclusion that there are 1.) no significant visual resource environmental justice issues related to the operation of this project, and 2.) no minority or low-income populations would be significantly or adversely impacted.

If the Energy Commission approves the project, staff recommends conditions of certification to minimize impacts to the greatest extent possible and to comply with applicable LORS pertaining to aesthetics or preservation and protection of sensitive visual resources.

INTRODUCTION

Visual resources consist of the viewable natural and built features of the environment. In this section staff evaluates the impacts on visual resources resulting from the

[1] Block 2612, Block Group 2, Census Tract 37 (U.S. Census 2010).

construction and operation of the HECA project and adjoining OEHI component. Staff bases its evaluation on information contained in the CEQA Guidelines, Aesthetics, to determine if the project would:

1. Cause a significant impact under CEQA.
2. Comply with applicable federal, state, and local LORS pertaining to aesthetics and preservation and protection of sensitive visual resources.

To provide a consistent framework for this analysis, a standard visual assessment methodology developed by staff and applied to numerous siting cases in the past was employed in this study. A description of this methodology is provided in **Appendix VR-1**.

REGIONAL SETTING

The proposed HECA project and its OEHI component would be located within the southwestern portion of the San Joaquin Valley, which stretches from the Sacramento-San Joaquin Delta in the north to the Tehachapi Mountains to the south. Various California coastal ranges line the valley to the west, including the Diablo and Santa Ynez, and the Sierra Nevada act as the eastern valley boundary.[2]

The proposed HECA project site is located on 453 acres of farmland, approximately 1.5 miles northwest of the unincorporated community of Tupman and four miles southeast of the unincorporated community of Buttonwillow. The site is bounded by Adohr Road on the north, Tupman Road on the east, irrigation canals and farmland to the south, and the Dairy Road right-of-way (ROW) to the west.

The proposed OEHI component is located a few miles southwest of the HECA project site on the existing 48,000-acre Elk Hills Oil Fields (EHOF). The EHOF is located 26 miles southwest of the city of Bakersfield in western Kern County. The project site is bounded by the California Aqueduct to the immediate north, Highway 5 (I-5) further to the north and east, Highways 119 and 33 to the south, Highway 33 to the west and Highway 58 to the northwest. Elk Hills Road runs north and south through the middle of the project site.

HECA

The topographic gradient of the area slopes gradually to the west. The generally flat terrain across the valley allows for open, panoramic views to the north, northwest, and east. Land immediately surrounding the HECA project site is primarily used for farming purposes. Highway commercial uses are located where Stockdale Highway intersects with Interstate 5 (I-5), more than 2 miles northeast of the project site. The California Aqueduct passes within approximately 1,900 feet of the southern boundary of the project site. The Elk Hills – Buttonwillow Airport is approximately 5 miles northwest of the project site. This airport covers approximately 216 acres, has one runway, and generally supports small private planes.

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[2] **Visual Resources Figures 1** and **2** show the locations of the HECA and OEHI sites, respectively.

The western border of the Tule Elk State Natural Reserve (Reserve) is approximately 1,700 feet east of the project site. The approximately 955-acre Reserve provides protected habitat for the Tule Elk. The Tule Elk Reserve State Park is located at the north end of the Reserve and is approximately three-quarters of a mile from the project site. The Park includes a visitor center, shaded picnic areas, and an observation deck for visitors to view the Reserve area and to see the Tule Elk in their habitat. In 2011, a total of 4,618 people visited the Reserve. As of June 2012, 1,977 people have been recorded as visitors.[3]

OEHI

The topography of the OEHI site has been extensively altered to accommodate the large flat pads and access roadways required for operation and maintenance of the oil field. Elevations of hills on the project site vary and range up to 1,551 feet above mean sea level. The highest topographic feature in the region is Hillcrest Point, which rises to 1,542 feet above mean sea level in the EHOF, in the northwest corner of the OEHI project site.

The city of Buttonwillow and the California Aqueduct/West Side Canal are located directly to the north of the project site. Lands to the immediate east include Coles Levee Ecological Preserve, Kern Water Bank Authority, Tule Elk Reserve State Park, and the Kern River. To the west of the project site include McKittrick Valley and portions of Buena Vista Valley. Finally, to the south of the project site includes Buena Vista Valley, another large oil field, undeveloped areas, and, further south, the city of Taft.

PROJECT SITE

HECA

The proposed 453-acre HECA project site is predominantly used for agricultural purposes, including the cultivation of cotton, alfalfa and onions. The project's most publicly visible structures are identified below in **Visual Resources Table 1**.

Visual Resources Table 1
Summary of Most Publicly Visible Structures (HECA)

Component	Height (feet)	Diameter (feet)
Gasification Structure/Feedstock Dryer/Crusher	305	270 x 125
CO_2 Vent	260	4
Gasification Flare	250	10
Rectisol Flare	250	2
SRU Flare	250	2
AGR Methanol Wash Column	235	20
HRSG Stack/HRSG	213/90	20
Air Separation Column Can ASU Column (Cold Box)	200 205	110 × 40 × 30

[3] See Alluis, email comm., 2012.

Visual Resources Table 1
Summary of Most Publicly Visible Structures (HECA)

Component	Height (feet)	Diameter (feet)
Gasification Flare Structure	200	65 × 65
Slurry Preparation Building	165	140 × 40
Tail Gas Thermal Oxidizer Stack	165	3
Feedstock Barn	160	250 × 650
Sour Water Stripper	150	8
Nitric Acid Absorber Vent	145	4
Additional AGR Columns	75–140	12–18
Feedstock Barn	160	250 × 650
Urea Plant Absorbers (HP/LP)	130/50	26/30
230-kV Transmission Line	110	2.1 miles
Urea Transfer Towers (5)	100	28 × 30
Wastewater ZLD Evaporator A	100	12
Wastewater ZLD Evaporator B	100	12
Feedstock Transfer Tower/Tower B/Crusher Vent	100	35 × 45
Heat Recovery Steam Generator Structure	90	122 × 115
Liquid Oxygen Storage Tank	90	42
Process Wastewater ZLD Evaporator	80	5
Limestone Fluxant Storage Building[4]	80	30
Auxiliary Boiler Stack/Auxiliary Boiler	80/80	6
Ammonia Unit Startup Heater	80	21 × 81
Ammonia Storage Tanks (2)	70	90
Feedstock Crusher Station	75	48 × 35
Fine Slag Handling Enclosure	70	172 × 52
Urea Reclaim Loadout Building	70	135 × 20
Urea Storage (4 Domes)	70	162
Tail Gas Treating Unit Columns	60–70	4–6
Feedstock Truck Unloading Vent	60	5
Power Block/Gasification Cooling Tower	55	850 × 120
ASU Cooling Tower	55	205 × 120
Combustion Turbine Generator Structure	50	12
CO_2 Compressor Enclosure	50	110 × 110
CTG Air Filter	50	–
Sour Shift/Low Temp Gas Cooling Unit	50	235 × 40
Urea Plant Low Pressure Absorber	50	??
Urea Pastillation Vent	50	??
Urea Bucket Elevator	50	20 × 20
230-kV Switchyard	–	–
Wastewater ZLD Feed Tank A	48	120
Wastewater ZLD Feed Tank B	48	120
Urea Ammonium Nitrate	48	120

[4] On April 10, 2013, staff was informed that the applicant intends to install a storage building for limestone fluxant at the project site. Since it is unlikely that the applicant could prepare materials in time for an adequate visual impact analysis by staff in the PSA, an analysis of the building will be performed during the FSA stage.

Visual Resources Table 1
Summary of Most Publicly Visible Structures (HECA)

Component	Height (feet)	Diameter (feet)
Firewater Tank	48	110
Water Treatment Plant Tanks (Raw, Treated, Purified, Backwash, Utility De-mineralized)	32–48	50–100
Feedstock Truck Unloading Building	44	82 × 36
Methanol Storage Tank	40	40
ASU Main Air Compressor Enclosure	40	46 × 119
AGR Refrigeration Compressor Structure	40	180 × 80
Process Wastewater Treatment Feed Tank	40	60
Flare Knock Out Drums (3) Gasification Settler	35 35	?? 85
Power Distribution Centers	25	120 × 15

Notes:
AGR = acid gas removal
ASU = air separation unit
CO_2 = carbon dioxide
CTG = combustion turbine generator
HRSG = heat recovery steam generator
SRU = sulfur recovery unit
ZLD = zero liquid discharge
Source: Hydrogen Energy International 2012

LIGHT, GLARE, AND FLARE EFFECTS[5]

The lighting system for the HECA project would provide plant personnel with illumination in both normal and emergency conditions. The system would consist primarily of alternating current (AC) lighting and direct current (DC) lighting for activities and emergency egress required during an outage of the project's AC electrical system. Lighting for the project would generally be required in these areas of the project site:

- Building interior, office, control, and maintenance areas
- Building exterior entrances
- Outdoor equipment platforms and walkways
- Transformer and switchyard areas
- Entrance gate

The lighting system is intended to provide personnel with illumination for project operation under normal conditions, means of egress under emergency conditions, and emergency lighting to perform manual operations during a power outage of the normal

[5] The Federal Aviation Agency (FAA) has stated that: "Any temporary or permanent structure, including all appurtenances, that exceeds an overall height of 200 feet (61m) above ground level (AGL) or exceeds any obstruction standard contained in 14 CFR part 77, should normally be marked and/or lighted." Several major components for the HECA project would meet or exceed the 200-foot height limit, including: the CO_2 Vent (260 feet), SRU Flare (250 feet), Gasification Flare (250 feet), Rectisol Flare (250 feet), Gasification Structure/Feedstock Dryer/Crusher (305 feet), Gasification Structure (200 feet), and the AGR Methanol Wash Column (235 feet). On May 25, 2012, the FAA issued a set of "Determination(s) of No Hazard to Air Navigation" to the applicant stating that the proposed HECA power plant structures would not be a hazard to air navigation provided that the aforementioned structures are marked/lighted in accordance with FAA Advisory Circular 70/7460-1 K Change 2, Obstruction Marking and Lighting, paint/red lights - Chapters 3 (Marked), 4, 5 (Red), & 12 (See "HECA Applications for Notice of Proposed Construction or Alteration (Off Airport) (TN# 66029)").

power source. The lighting system would be designed and installed to meet Occupational Safety and Health Administration (OSHA) minimum standards, and to offer maximum illumination of operating work areas while minimizing off-site illumination.

The project includes flares for burning excess gas – for example, during start-up or emergency or upset conditions – including a gasification flare and a Sulfur Recovery Unit (SRU) flare. These flares could create additional lighting impact if operated at night.

VISIBLE WATER VAPOR PLUMES

Operation of the HECA power plant when the outside temperature is low and humidity is high could result in formation of a publicly visible water vapor plume(s) when waste heat (exhaust) is emitted from the project's cooling towers. Depending on local, seasonal weather conditions, the potential exists for vapor plumes to be visible from the following sources at the project site, including: the Air Separation Unit (ASU) cooling tower, 13-cell power block cooling tower, and coal dryer stack.[6]

ELECTRICAL TRANSMISSION LINE

A 230-kV transmission line would connect the HECA project to a future PG&E switching station approximately 2 miles east of the project site (Hydrogen Energy International 2012).[7] The transmission line route would leave the northeast corner of the project site, heading east to Tupman Road, continuing north to near Adohr Road, and finally east to the new Pacific Gas & Electric (PG&E) switching station near Elk Valley Road.

Construction of the transmission line would require installing approximately 26 (15 off-site and 11 on-site) tubular-steel transmission structures and the supporting foundations. The project intends to use single-pole, galvanized steel, tangent structures for the transmission towers. Each tower would range from 90 to 115 feet in height.

RAILROAD SPUR

Alternative 1 for the transportation of coal to the project site is an approximately 5-mile railroad spur that would connect the project site to the existing San Joaquin Valley Railroad (SJVRR) Buttonwillow railroad line, located north of the project site. The railroad spur would enter the northwest corner of the project site and would both deliver coal and export products during operations. If available, the railroad spur would also be used to deliver plant equipment during construction (Hydrogen Energy International 2012).

The newly constructed railroad spur would be a single track railroad and produce a temporary disturbance of 75 feet along the linear length (51.2 acres) plus three acres of the laydown area. After the project is completed, the spur would create a permanent disturbance 60 feet wide along the linear length (38.6 acres).

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[6] Please see discussion below in **Visible Water Vapor Plumes** and **Appendix VR-2: Visible Plume Modeling Analysis** for a detailed visual plume analysis.

[7] See **Visual Resources Figure 3**.

CONSTRUCTION LAYDOWN AND STAGING AREA

The on-site construction area for the HECA project would include a construction laydown area, construction parking, offices, and warehouse. Construction access would be from Stockdale Highway north of the project site, then south along Dairy Road and east on Adohr Road. All construction laydown and parking areas would be located within the project area and the controlled area.[8]

CO_2 PIPELINE

A CO_2 pipeline would be constructed to transfer the CO_2 produced by the HECA project to the OEHI CO_2 Processing Facility. The CO_2 pipeline route would be constructed underground at a depth of 5 to 100 feet below grade and leave the southwestern portion of the HECA project site to the processing facility. The route is approximately 3 miles in length. No visible components of the CO_2 pipeline are anticipated.

OEHI

The proposed OEHI site is located within the approximately 48,000-acre EHOF site. This site is predominantly used for oil extraction purposes. The project's most publicly visible structures are identified below in **Visual Resources Table 2**.

Visual Resources Table 2
Summary of Most Publicly Visible Structures (OEHI)

Component	Height (feet)	Diameter (feet)
V-4420 De-methanizer	120	--
DS-6330 Flare Stacks	78	36
DS-2050 Flare Stacks	78	36
V-3030 TEG Contactor	74	--
V-2060/65 Flumes	50	26
V-4520 CO_2 Absorber	40	42
C-4900 NGL Stabilizer	40	36
V-1010 Production Separator (Satellite)	35	102
T-2070/75 Vortex Tanks	24	55
T-2100/10 Water Tanks	24	67
T-2120/30 Oil Tanks	24	25
Maintenance/Warehouse Building	20	--
MCC Building	18	--
Compressor Shelter (RCF)	18	--
Compressor Shelter (CRP)	18	--
V-1020 Test Separator (Satellite)	15	48
Water Make-up Storage Tank	14	80
Administrative/Control Building	12	--
T-1030 Vent Tank/Stack (Satellite)	12	--

Source: Occidental of Elk Hills 2012

[8] See **Visual Resources Figure 4**.

CO_2 EOR PROCESSING FACILITY

The proposed CO_2 EOR Processing Facility (and its Tank Battery) would occupy 101.8 acres and be connected to the HECA project site via a proposed CO_2 pipeline (Occidental of Elk Hills 2012). The facility would be located approximately 2 miles southwest of the community of Tupman in Plot Section 27S. The facility would serve as a centralized hub for the incoming CO_2 from HECA and, subsequently, distribute the CO_2 to the various satellite facilities/wells.

LIGHT, GLARE, AND FLARE EFFECTS

Nighttime lighting presently in the area surrounding the project consists of low scattered lighting associated with rural residences, farming operations, surrounding communities, and headlights from motorists on area roadways. Developed oil production sites on the OEHI site currently produce substantial amounts of trespass and nighttime light.[9]
The CO_2 EOR Processing Facility would include security lighting capable of producing a substantial concentrated source of nighttime light. The lighting at the facility would be most visible from the city of Tupman and from a few locations along Tupman Road where views of the facility are not otherwise blocked by topography. The 13 satellite stations and well sites are not expected to have lighting. The facility would also be equipped with two flares that would have the potential to emit light during nighttime operations.

APPLICANT PROPOSED MITIGATION MEASURES

The applicant's discussion of the visual impacts of HECA and the OEHI component are found in Section 5.11.2.4 (pages 5.11-17 to -26) in the Application for Certification (AFC) and Section 4.1.5 (pages 4.1-17 and 4.1-19 to -22) in Appendix A, respectively. The applicant concludes that the following mitigation measures would reduce visual impacts to a less-than-significant level.

HECA

The applicant proposes the following design features and mitigation measures to reduce visual impacts to less-than-significant levels:

- Structures, stacks, buildings, and storage tanks will be painted in accordance with Energy Commission guidelines, and colors will be selected to blend in with the existing visual conditions.
- The colors will provide subtle variations and contrast. The selected color will help the project to blend more naturally with the natural setting.
- Reflectivity of surfaces will be reduced by using non-reflective elements where practical.
- Lighting on the project site will be limited to areas required for safety, will be directed on site to avoid backscatter, and will be shielded from public view to the extent practical.

[9] See Taft General Plan EIR, 2009.

- All lighting that is not required to be on during nighttime hours will be controlled with sensors or switches operated so that the lighting will be on only when needed.
- High-pressure sodium vapor fixtures will be used. These lights typically produce low-intensity amber light, which will reduce visual contrast with the night sky.
- Stacks and other tall project elements will be lit in accordance with FAA guidelines.
- After construction, areas where pavement or vegetation has been removed will be restored to be consistent with the surrounding area. Pipeline routes may also follow road rights-of-way and therefore will be placed under pavement or prepared dirt surfaces.
- While the project includes the above features that reduce visual impacts from its construction or operation, a potentially significant visual impact has been identified by the applicant for the nearest residential viewers to the project site (KOP 1). The applicant proposes to mitigate this impact with the following mitigation measure:
    - Prepare Conceptual Landscaping Plan for screening purposes. The plan will include information on the plant species proposed; their size, quantity, and spacing at planting; their expected heights at 5 years and at maturity; and their expected growth rates.[10]

OEHI

OEHI proposes the following mitigation measures to reduce visual impacts to less-than-significant levels:

- The surfaces of all structures, equipment, piping, and other associated above-ground project components will be given low reflectivity finishes with neutral colors to minimize the contrast of the structures with their backdrops.[11]
- In areas requiring major topographic adjustment (including but not limited to the CO2 EOR Processing Facility, satellite locations, new well sites, buried pipelines, etc.), topsoil from existing grade to be cut/filled/trenched will be removed and stockpiled during rough grading and/or trenching operations. Topsoil will be reapplied consistently across the new grades and stabilized to allow natural revegetation.[12]
- For any overhead transmission lines, lattice steel towers will not be used. If tubular steel poles are used (instead of wood) they will be painted light-gray colors or be dulled galvanized steel.[13]
- During construction, temporary construction areas, including construction parking, offices, and construction laydowns, will be located within OEHI existing operations and out of direct view of the public, to the maximum extent feasible.[14]

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[10] See **Visual Resources Mitigation Measure 1 (VRMM-1)**.
[11] See **Mitigation Measure AES-1**.
[12] See **Mitigation Measure AES-2**.
[13] See **Mitigation Measure AES-3**.
[14] See **Mitigation Measure AES-4**.

- The project will utilize existing pipeline corridors, ROWs, roads, storage areas, and previously disturbed acreage to the maximum extent feasible. All project components will be designed to minimize disturbed footprint during construction.[15]
- All outdoor lighting will be the minimum required to meet safety and security standards. All light fixtures will be hooded and/or shielded to reduce potential for glare effects and to prevent light from spilling off the site or up into the sky.[16]

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Visual Resources Table 3 generally describes LORS pertaining to aesthetics and protection of sensitive visual resources that are applicable to the proposed projects. Local LORS would apply to HECA. However, no federal or state LORS pertaining to visual resources would be applicable. The HECA project's consistency with specific policies and ordinances is discussed below under "Compliance with Laws, Ordinances, Regulations, and Standards."

Visual Resources Table 3
Applicable Visual Resources LORS

Source	Policy and Strategy Description
Kern County General Plan – Land Use, Open Space, and Conservation Element	
1.8 Industrial (Kern County Planning Department 2009)	Policy 6. Encourage upgrading the visual character of existing industrial areas through the use of landscape elements, screens, or buffers.
	Policy 7. Require that industrial uses provide design features such as screen walls, landscape elements, increased height and/or setbacks, and lighting restrictions between the boundaries of adjacent residential land use designations so as to reduce impacts to residential uses relating to light, noise, sound, and vibration.
1.10.7 General Provisions, Light and Glare (Kern County Planning Department 2009)	Light and Glare Policy 47. Ensure that light and glare from discretionary new development projects are minimized in rural as well as urban areas.
	Light and Glare Policy 48. Encourage the use of low-glare lighting to minimize nighttime glare effects on neighboring properties.
Kern County Zoning Ordinance – Chapter 19.12 Exclusive Agriculture (A) District	
19.12.120 Landscaping	States that no landscaping is required in the A District, except where the proposed use is subject to a plot plan review pursuant to Chapter 19.80, Special Development Standards, which establishes development standards for industrial and other land uses.

[15] See **Mitigation Measure AES-5**.
[16] See **Mitigation Measure AES-6**.

Visual Resources Table 3
Applicable Visual Resources LORS

Source	Policy and Strategy Description
19.12.110 Signs	Describes the types of signs that are permitted in the A District, in accordance with the requirements of Chapter 19.84, Signs. Various temporary signs are permitted, as are agricultural and institutional identification signs.
Kern County Zoning Ordinance – Chapter 19.81 Dark Skies Ordinance	
19.81.040 General Requirements	Describes general standards for all outdoor lighting fixtures subject to the dark skies ordinance. Applicable standards include those that address shielding, prohibited light source types, fixture height, fixture types, uplighting, and outdoor facilities, advertising signs, searchlights, and hours of operation.
Kern County Zoning Ordinance – Chapter 19.82 Off-Street Parking	
19.82.090 Parking Area Design and Development Standards	Section I addresses standards for landscaping of parking lots containing ten or more spaces. Section J addresses standards to prevent headlight glare to public streets or roads beyond the parking facility. Section K requires that parking area lighting be directed away from adjacent properties.
Kern County Zoning Ordinance – Chapter 19.84 Signs	
19.84.020, 19.84.030, and 19.84.040 Design and Development Standards – Monument Signs, Pole Signs, and Signs Attached to Buildings	These three sections of Chapter 19.84 address standards for freestanding monument and pole signs and signs attached to a building or wall. Specific standards are provided for the height, area, and spacing of signs; signage lighting; and other design details. Monument signs may not be located within any existing or designated future road right-of-way line.
Kern County Zoning Ordinance – Chapter 19.86 Landscaping	
19.86.020 Landscaping Standards – Generally	Requires compliance with the minimum standards for landscaping except as may be modified in connection with the approval of a discretionary development permit or as otherwise authorized by the Planning Director. Minimum plant and tree sizes are 15 gallons for trees, 5 gallons for shrubs, and 1 gallon for small shrubs and groundcovers. Landscaping and irrigation systems must be continuously maintained in good condition. Section 19.86.020 requires landscaping to be consistent with the State Fire Safe regulations contained in Section 4290 of the Public Resources Code and in Title 14, California Code of Regulations, Division 1.5, Chapter 7, Subchapter 2.
19.86.060 Landscaping Standards – Industrial Uses	A minimum of five percent (5%)of the developed area shall be landscaped. A maximum of one-half (1/2) of the five percent (5%) may be turf or an alternative ground cover. Along any interior property line abutting residentially zoned lots, trees shall be planted. The planters shall be sufficiently large and protected so that a parked car does not extend into the

Visual Resources Table 3
Applicable Visual Resources LORS

Source	Policy and Strategy Description
	minimum four- (4-) foot by four- (4-) foot tree planting area which shall be landscaped with ground cover, shrubs, and climbing plants. Planters or landscaped areas shall be provided in off-street parking areas in accordance with the requirements of Subsection I of Section 19.82.090 of this title. No plant material that will grow to a height of more than eighteen (18) inches shall be planted in the street right-of-way, except where authorized by the Kern County Roads Department. Within each planter or landscaped area, an irrigation system and live landscaping shall be provided and maintained, except that an irrigation system is not required to serve planters or landscaped areas devoted exclusively to native indigenous plants. Automatic timers shall be utilized and the use of drip irrigation systems shall be strongly encouraged. Landscaping materials and trees installed in planters or landscaped areas shall be selected based upon their adaptability to the climatic, geologic, and topographical conditions of the site. Use and protection of native plants and natural areas is highly encouraged. If more than 2,500 square feet of landscaping area will be required, landscaping and irrigation for the project shall comply with the Water Efficient Landscape requirements set forth in Sections 19.86.065, 19.86.070 and 19.86.080 of this chapter.
19.86.070 Landscape and Irrigation Plan – Required	Identifies classes of projects that are subject to preparation of landscape and irrigation plans, in accordance with the Kern County Water Efficient Landscape Guidelines. Industrial development projects with a cumulative landscape area of 2,500 square feet or more are included in the list of projects. Landscape plans must be prepared by either a licensed landscape architect or licensed landscape contractor. Irrigation plans must be prepared by a licensed landscape architect, certified irrigation designer, or licensed landscape contractor.
19.86.080 Landscape and Irrigation Plan – Review and Approval	Addresses submittal of conceptual landscape and irrigation plans for projects requiring a discretionary or ministerial approval. Addresses requirements relating to preparation and submittal of Landscape Documentation Packages. Required elements include details on the development area, landscape area, soil characteristics, and water supply and use.

Visual Resources Table 3
Applicable Visual Resources LORS

Source	Policy and Strategy Description
19.86.090 Landscape Installation – Timing	Requires installation of the landscape and irrigation systems or posting of an acceptable financial assurance prior to issuance of an occupancy permit. Also requires submittal of a properly executed Certificate of Completion to the Kern County Engineering, Surveying, and Permit Services Department/Building Inspection Division.

Note: The complete text of Kern County's general plan and zoning ordinance, is available at: http://www.co.kern.ca.us/planning/pdfs/kcgp/KCGP.pdf and http://www.co.kern.ca.us/planning/pdfs/KCZOJul12.pdf, respectively.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

This section includes information about the following:

- Method and threshold for determining significance
- Direct/indirect/induced impacts and mitigation
- Cumulative impacts and mitigation

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

CEQA defines a "significant effect on the environment" to mean a "substantial, or potentially substantial, adverse change in any of the physical conditions within the area affected by the project including objects of historic or aesthetic significance" (California Code of Regulations, Title 14, Section 15382).

To determine whether there is a potentially significant visual resources impact generated by a project, Energy Commission staff reviews the project using the CEQA Guidelines Appendix G Environmental Checklist pertaining to "Aesthetics". The checklist questions include the following:

- Would the project have a substantial adverse effect on a scenic vista?
- Would the project substantially damage scenic resources, including, but not limited to trees, rock outcroppings, and historic buildings within a state scenic highway?
- Would the project substantially degrade the existing visual character or quality of the site and its surroundings?
- Would the project create a new source of substantial light or glare which would adversely affect day or nighttime views in the area?

DIRECT/INDIRECT/INDUCED IMPACTS AND MITIGATION

Scenic Vista

For the purposes of this analysis, a scenic vista is defined as a distant view of high pictorial quality perceived through and along a corridor or opening, or from a designated scenic area. Staff has conducted site visits to the project area and researched national, state and local scenic vista designations in the vicinity of the project area.

The proposed HECA project would be constructed in a rural agricultural area in the San Joaquin Valley. The proposed OEHI component would be constructed in the existing EHOF, which is located 26 miles southwest of Bakersfield in western Kern County (County). Extensive areas in this region are generally free from urban encroachment. Similar rural areas away from major highway corridors may provide a restful and relatively benign visual environment for some viewers. However, there is no place in either project vicinity with the level of scenic appeal that would distinguish a specific view as a scenic vista.

Therefore, the proposed projects would have no impact to scenic vistas.

Scenic Resources

None of the elements of the proposed HECA or its OEHI component would be located near a designated scenic highway corridor or area where scenic resources could be damaged. According to the California Department of Transportation, the State Scenic Highway System includes a list of highways that are either eligible for designation as scenic highways or have been officially designated. Segments of State Routes (SRs) 14 and 58 in the eastern part of the county are on the list of eligible state scenic highways. These highways are east of the southern slope of the eastern Sierra Nevada. No views of the project site would be possible at this distance. No roadways near the project area are subject to aesthetic management goals or objectives of local jurisdictions. Further, there are no officially designated or eligible state scenic highways in proximity to the OEHI component that could be impacted by the proposed project. Therefore, the proposed projects would have no impact to scenic resources.

Visual Character or Quality

The method for this assessment of impacts on visual resources is primarily adapted from guidelines used by the U.S. Forest Service (USFS), the U.S. Bureau of Land Management, and the U.S. Department of Transportation. The process to evaluate the potential impacts to visual resources from implementation of the HECA project involves the following five steps:

- Define the visual environment, or visual sphere of influence (VSOI), within which visual impacts could occur.
- Describe sensitive viewpoints and the process to select key observation points (KOPs), or critical viewpoints, within the VSOI for the project.
- Evaluate the potential effects of the project on visual resources based on the estimated visual sensitivity of the viewing public.
- Evaluate the estimated magnitude of the visual change that would occur following project implementation.
- Evaluate the probability that the landscape would demonstrate a noticeable visual impact with project implementation

The ratings for overall visual sensitivity and overall visual change are combined to determine the visual impact for each KOP. The assessment of visual impacts by Energy Commission staff is based on the change that would occur from the introduction of new built elements in the VSOI. The overall visual change is based on an average of the values for contrast, dominance, and view blockage for each KOP. The rating scale to assess visual sensitivity and visual change ranges from low to high for each factor. An assessment of visual absorption capability (VAC) is also used to assess the capacity of the landscape for each KOP to absorb visual alterations without significantly affecting the visual character of the landscape (Bacon 1979).

VISUAL SPHERE OF INFLUENCE (VSOI)

The VSOI for the project represents the area within which the proposed HECA and OEHI component could be seen and where impacts to visual resources could potentially occur. Overall, the proposed HECA site would have a high visibility to several nearby residences and roadway users within 0.5 mile (foreground view), within 1.0 mile (middleground view), and other locations within the surrounding area, 3.5 to 5.0 miles and beyond (background view). The proposed OEHI site has the potential to be visible to several nearby residences and roadway users within 3.0 miles of the site. Beyond 5 miles, the facilities would be either not visible due to topography, natural and/or human-made screening, or of such a small size in the background that it would hardly be noticeable. It may be conceivable that both the HECA and OEHI sites could be simultaneously visible from several KOPs. However, due to the considerable distance and the elevated topography of the Elk Hills range in between the sites, it is highly unlikely that the sites could be simultaneously visible from any KOPs. In any event, the KOPs chosen represent the reasonable worst-case scenario for visual impacts resulting from each of the project components.

SENSITIVE VIEWPOINTS

Results of the VSOI analysis and photographic survey for the HECA project resulted in the conclusion that the most sensitive viewpoints within the VSOI were from those areas with middleground views of the project site. An inventory of stationary sensitive viewpoints (also referred to as sensitive receptors) within approximately 5 miles of the proposed HECA project site (and within approximately 2,000 feet of the proposed 230-kV transmission line) is provided below in **Visual Resources Table 4**. Because there are no designated scenic highways or roadways in the region, no such highway or roadway segments are included in the table. However, potential effects of the project on viewers traveling on nearby roads and highways are addressed below.

Visual Resources Table 4
Sensitive Receptors within Approximately 5 Miles of Proposed HECA Project Facilities

Type of Receptor	General Description and Location	Direction and Approximate Distance from Proposed HECA Project Facilities
Residences	Residences on two adjacent properties near the intersection of Station Road and Tule Park Road	1,500 feet east of the project site 2,200 feet south of the 230-kV transmission line

Visual Resources Table 4
Sensitive Receptors within Approximately 5 Miles of Proposed HECA Project Facilities

Type of Receptor	General Description and Location	Direction and Approximate Distance from Proposed HECA Project Facilities
Residence	Residence on east side of Tupman Road below Station Road	3,300 feet southeast of the project site
Tule Elk Reserve State Park	Picnic area and viewing platform on Station Road at the north end of the Reserve	1,700 feet east of the project site
Residences	Three or four residences on the south side of Stockdale Highway near the East Side Canal	1 mile north of the project site
Residence	Residence near the intersection of Dairy Road and Stockdale Highway	1.3 miles north of the project site
Residence and Horse Ranch	Residence and adjacent horse ranch on the north side of Stockdale Highway	1.5 miles northeast of the project site
Residences	Two or three residences on the north side of Stockdale Highway east of Dunford Road	1.5 miles northwest of the project site
Residences	Four residences on the north side of Stockdale Highway between Dunford and Freeborn Roads	2.25 miles northwest of the project site
Residence	Residence on Dunford Road above Stockdale Highway	2.25 miles northwest of the project site
Group of Housing Units	Group of 6–8 separate housing units on the south side of Stockdale Highway adjacent to the Weed Island drainage ditch	2.25 miles northwest of the project site
Elk Hills Elementary School	Kern Street on the west side of the community of Tupman	2.5 miles southeast of the project site
Residences	Two or three mobile homes on the west side of Elic Valley Road south of Stockdale Highway	2.5 miles northeast of the project site 1,800 feet north of the 230-kV transmission line

Source: Energy Commission Staff 2012

Results of the VSOI analysis and photographic survey for the OEHI component resulted in the conclusion that the most sensitive viewpoints within the VSOI were from those areas with background views of the project site. An inventory of stationary sensitive viewpoints (also referred to as sensitive receptors) within approximately 5 miles of the proposed OEHI site is provided in **Visual Resources Table 5**.[17] Because there are no

[15] In regards to the references made to distances/cardinal directions between the OEHI component and Sensitive Receptors in **VISUAL RESOURCES Table 5**, “Project Site” is considered to be the CO2 EOR Processing Facility, as this would be the most prominent/visible element of the OEHI project.

designated scenic highways or roadways in the region, no highway or roadway segments are included in the table. However, potential effects of the project on viewers traveling on nearby roads and highways are addressed below.

Visual Resources Table 5
Sensitive Receptors within Approximately 5 Miles of Proposed OEHI Facilities

Type of Receptor	General Description and Location	Direction and Approximate Distance from Proposed OEHI Project Site
Subdivision (Residences, School, Post Office, etc)	Subdivision near the intersection of Grace Avenue, Kern Street, and Emmons Boulevard	1.5 miles northeast of the project site;
Residences	Residences near the intersection of Taft Highway (State Highway 119) and Golf Course Road	3.5 miles southeast of the project site
Residences	Residences near the intersection of Taft Highway (State Highway 119) and Tank Farm Road	4 miles southeast of the project site
Residences	Residences near the intersection of Tank Road and Tank Farm Road	4 miles south of the project site
Residences	Residences near the intersection of Mesquite Street and Tamarisk Avenue	5 miles southwest of the project site
Residences	Residences near the intersection of Escudo Drive and Gibbs Street	5.3 miles southwest of the project site
Residences	Residences near the intersection of Airport Road and Valley West Road	5.4 miles southwest of the project site

Source: Occidental of Elk Hills 2012

HECA

KEY OBSERVATION POINTS

A KOP is selected to be representative of the most critical viewpoints from off-site locations where the project would be visible to the public, for example: recreational and residential areas, travel routes, bodies of water, as well as scenic and historic resources. Because it is not feasible to analyze all the views in which a proposed project would be seen, it is necessary to select a KOP that would most clearly display the visual effects of the proposed project. A KOP may also represent a primary viewer group(s) that would potentially be affected by the project. Staff evaluates the existing physical environmental setting, the KOP, and the visual change created by the proposed project to the VSOI.

The applicant has provided KOP photographs that show the existing physical condition without the HECA and its OEHI component, and has prepared photographic simulations to show how the proposed project would appear in both existing conditions. **Visual Resources Figure 5** shows the locations of the six KOPs used for this analysis:

- KOP 1 – View of the HECA project site, looking west from Station Road;
- KOP 2 – View of the HECA project site, looking south-southeast from Stockdale Highway;
- KOP 3 – View of the HECA project site, looking north-northwest from the Elk Hills Elementary School playground;
- KOP 4 – View of the HECA project site, looking south-southwest from the Stockdale Highway near the I-5 interchange;
- KOP 5 – View of the HECA project site, looking south-southwest from the southbound lane on I-5;[18] and
- KOP 6 – View of the HECA project site, looking south-southeast from Brite Road.

KOP 1

<u>Visual Sensitivity</u>

KOP 1 was photographed from Station Road near the eastern boundary of the HECA project site.[19] The middle of the HECA project site is approximately 2600 feet west of this viewpoint. The VSOI at this location includes views of flat, irrigated farmland extending from the foreground through the middleground of the view and in both directions to the left and right (south and north) of the viewer. Views are dominated by green cultivated cropland in the foreground and middleground that contrasts with the muted browns and relatively barren landscape of the Elk Hills in the middleground. A faint impression of the Temblor Range in the background repeats the form and line of the Elk Hills. Above-ground utility lines on wooden poles are visible in foreground and middleground views. Station Road is a two-lane blacktop road in the view at KOP 1.

A former organic fertilizer production facility northwest of the project site is visible from KOP 1. The complex of grain storage silos, buildings, and other structures is circled by palm trees and appears as a collection of irregular, built shapes compared to the surrounding open croplands. The surfaces of some of the structures are more reflective than other elements in the view.[20] Oil production work in the Elk Hills Oil Field Unit is generally too far away for equipment to be discernible in the VSOI.

Little variation is present in the form and line of landscape elements at this location. Qualities that are often associated with memorable or visually powerful landscapes are not present at KOP 1. In other words, the landscape lacks interesting visual features and variations in forms, textures, and patterns in the vegetation and landforms that are often present in high quality views. Although views at this location are somewhat harmonious due to the overall lack of urban encroachment, no particular landscape feature or landform draws the viewer's attention. Visual quality for KOP 1 is characterized as moderate.

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[18] KOP 5 provides a view from a stationary point adjacent to the southbound lanes of I-5. This segment of I-5 in the vicinity of the project site is oriented to the southeast. Energy Commission staff has concluded that the project site would not be within view for motorists traveling south along this segment of I-5. Therefore, KOP 5 is not analyzed in this staff assessment.

[19] See **Visual Resources Figures 6a** and **6b**.

[20] See view of the former organic fertilizer production facility in **Visual Resources Figure 7a**.

Viewers at or near KOP 1 include residents at two adjacent properties near the intersection of Station Road and Tule Park Road and motorists on Station Road. Viewer concern for nearby residents is expected to be high whether or not their homes are oriented to permit direct and unscreened views of the project site. The Tule Elk Reserve State Park is approximately 2,000 feet east of the viewpoint for KOP 1. Visitors to the Reserve have direct, unscreened views of the project site during their trips to the area. Viewer concern for this viewer group is expected to be moderate to high. Motorists using local roadways include employees of agricultural, oil production, and other businesses whose focus is on their travels and daily pursuits. This viewer group is expected to have moderate viewer concern. For this combination of viewer groups, viewer concern for KOP 1 is considered moderate to high.

Under existing conditions, the site is generally not screened by landforms, vegetation, or built structures, and views of the project site from KOP 1 are unimpeded. Visibility of the project site at this location is high.

Viewers for KOP 1 include motorists, residents, and recreationists.[21] This visual resources analysis included a review of traffic volume data compiled by the Kern Council of Governments (Kern COG) for its Regional Transportation Monitoring Improvement Program. The most recent data compiled by Kern COG includes traffic counts on certain roadways in the project area. Traffic counts taken on Morris Road south of Stockdale Highway were included in the estimate of number of viewers for KOP 1. It is assumed that motorists on Morris Road include local residents as well as visitors to the Reserve. As of January 1, 2004, the annual average daily traffic (AADT) volume at this location was 370 (Kern COG 2012).[22]

Based on data maintained by California State Parks staff, a total of 4,618 people visited the Reserve in 2011 (an average of approximately 13 recreationists per day).[23] As of June 1, 2012, 1,977 people have been recorded as visitors.[24] It is estimated that between two and five residences are near the viewpoint for KOP 1. Based on Kern COG traffic data, estimated number of visitors to the Reserve, and the number of nearby residences, the rating for number of viewers at KOP 1 is considered low.

The duration of view for KOP 1 varies depending on whether the viewers are nearby residents, motorists, or visitors to the Reserve. Viewer duration is considered high for residents with a direct view of the project site at this location. Motorists on Morris Road and Station Road would be traveling at relatively low speeds and may have views of the project site lasting from 20 to 60 seconds. For this viewer group, the rating for duration of view is considered moderate. Recreationists would likely see the project site during their visits to the area and may have views lasting from 1 to 2 minutes. The rating for

[21] See **Appendix VR-1**.

[22] AADT is the total volume of traffic on a highway segment for 1 year divided by the number of days in the year. AADT volumes reported on the Kern COG website are typically a count conducted on a single day, adjusted using day-of-week and monthly factors from a control station to estimate the average volume over the year. AADT information can be located at: http://www.kerncog.org/cms/data/traffic-count-map.

[23] See Alluis, email communication, 2012.

[24] *Ibid*.

this duration of view is considered moderate to high. For this combination of viewer groups, duration of view for KOP 1 is considered moderate to high.

Although visibility of the project site is high, the number of viewers is low. Duration of view varies among the three identified viewer groups; average duration of view is moderate to high. Therefore, based on the ratings for visibility, number of viewers, and duration of view, *overall viewer exposure* for KOP 1 is considered moderate.

Visual quality is characterized as moderate. Viewer concern varies among the viewer groups; average viewer concern is moderate to high. Therefore, based on the ratings for the above visual sensitivity factors, *overall visual sensitivity* is considered moderate to high.

Visual Change

The visual simulation for KOP 1 shows buildings and structures as they would appear at the HECA project site for a viewer near the intersection of Station Road and Tule Park Road. The closest structures would be located approximately 3,600 feet west of the viewer just beyond the foreground. Some of the tallest structures at the plant site would be clearly visible from KOP 1. From south to north (left to right) some of the proposed structures would include: a urea ammonium nitrate storage structure, urea storage structure, transfer tower, feedstock barn, and another transfer tower.[25]

Construction of the HECA project structures would introduce a high degree of contrast into the VSOI. The low profile and simple horizontal forms and lines of the existing landscape created by the cropland and distant hills would be interrupted by the overall bulk, height, complexity, and geometry of the built structures at the project site. The uniformity of shapes and evenness of landforms created by the existing landscape for KOP 1 indicates low VAC for this view.[26] In other words, this landscape has a low capacity to visually withstand or absorb the new built elements into the VSOI.
The color contrast created by the gray tones and steel surfaces of the new structures would be strong in this environment. The hard surfaces of the constructed project components would contrast sharply with the relatively soft textures of the existing natural surfaces of the earth and vegetation. The degree of visual contrast that would be created by construction of the proposed project is considered high.

The simulation for KOP 1 shows the proportionate size of the HECA project structures as a whole relative to the existing visible natural and built features in the VSOI.[27] The new built structures would dominate the landscape. The existing expansive view of the Elk Hills and Temblor Range in the middleground and background would be partially blocked at this location. The degree of dominance and view blockage that would be created by the project is considered moderate to high. Therefore, for KOP 1, the *overall visual change* would be moderately high.

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[25] See **Visual Resources Figure 17**.
[26] See the discussion under “Contrast” in **Appendix VR-1**.
[27] See **Visual Resources Figure 6b**.

Visual Impact Determination

Overall visual sensitivity for KOP 1 is considered moderate to high and *overall visual change* is considered moderately high. Energy Commission staff concludes that introducing the publicly visible project structures into the existing view at KOP 1 would cause substantial degradation of the existing visual character of the site and its surroundings. Additionally, the applicant characterizes visual impact susceptibility and severity as "high" at KOP 1 and identifies a significant impact to visual resources at this location (Hydrogen Energy International 2012). Therefore, a significant impact to visual resources is identified for KOP 1.

The Amended AFC includes a visual resources mitigation measure (VRMM-1) recommending preparation of a conceptual landscape plan to screen views of the project site (Hydrogen Energy International 2012). However, during a discussion with Energy Commission staff on January 29, 2013, the applicant demonstrated that using landscaping for visual screening at KOP 1 would be difficult due to irrigation requirements.[28] As such, the applicant intends to provide an alternative mitigation measure – one that would provide off-site visual screening (landscaping) at the properties located at the intersection of Station Road and Tule Park Road. The applicant believes that this alternative mitigation measure would reduce visual impacts at KOP 1 to less-than-significant levels.[29] Further, the applicant has stated that it would "study the possibility of incorporating cost-effective architectural enhancements to the feedstock storage [structure]. . .to reduce contrast in color and texture. . .and exterior components to reduce contrast in storage area lines."[30]

Consistent with the applicant's proposed alternative mitigation measure, Energy Commission staff requests that the applicant prepare and submit an electronic copy of a conceptual off-site landscape plan and/or architectural enhancements to the feedstock storage structure for review by staff at least two months prior to publication of the Final Staff Assessment (FSA) for the project. The primary purpose of the off-site landscape plan and/or the architectural enhancements would be to show how they would contribute to screening views of the project to the maximum extent feasible at KOP 1 – including both the residences located at the intersection of Station Road and Tule Park Road and the Tule Elk Reserve State Park public use areas.[31] To ensure that the information provided in the off-site landscaping and/or architectural enhancements would allow for a thorough assessment of this impact, both items would need to include, at a minimum, the following elements:

- Information on the type of plant species proposed: size, quantity, and spacing at planting; expected height at 5 years and maturity; and expected growth rates. Staff

[28] See Rushmore et al., conference call, 2013. According to the applicant, the landscaping would be placed on top of the berm at the eastern border of the project site. Placing the landscaping on top of the berm would require an increased amount of water for irrigation purposes. However, according to the applicant, this increased demand for water to irrigate the landscaping cannot be accommodated within current potable water limits set forth by Kern County.

[29] See Response to CEC Data Request Set One: No. A117 (TN# 69490).

[30] *Ibid*.

[31] Staff requests that the plan be consistent with applicable sections of Chapter 19.86, Landscaping, of the Kern County Zoning Ordinance (**http://www.co.kern.ca.us/planning/pdfs/KCZOJul12.pdf**).

requires preparation of this information by a qualified professional arborist or botanist familiar with local growing conditions.

- Conceptual landscape plan.
- Use of a decorative wall or similar permanent built structure combined with landscape plantings and/or other built screening devices to maximize the effectiveness of the landscape plan. The decorative screen or wall shall be high enough to interrupt views of vertical project features to the maximum extent feasible for a person standing at or near KOP 1. The plan shall address and incorporate required setbacks of plantings and screening structures from public utilities and the road.
- Electronic and paper copies of 11-inch by 17-inch color photographic simulations at life size scale showing the landscaping 5 years after planting and at maturity from the residences located at KOP 1.
- Official copy of recorded agreement between the landowner(s) at KOP 1 and HECA, LLC detailing the applicant's conceptual landscape plan and the landowner(s) approval of said plan.
- Electronic and paper copies of 11-inch by 17-inch color photographic simulations at life size scale showing any architectural enhancements to the feedstock storage structure.

Staff may prepare a condition of certification to include in the FSA requiring implementation of the above landscape plan and/or architectural enhancements. The visual resources analysis in the FSA would assess effectiveness of the proposed off-site landscape plan, architectural enhancements, and other proposed conditions of certification to reduce the impact at KOP 1 to a less-than-significant level.

KOP 2

Visual Sensitivity

KOP 2 was photographed from the north side of Stockdale Highway between Dairy Road and Dunford Road.[32] The HECA project site is approximately 1.5 miles southeast of this viewpoint. Visible in the middleground of the VSOI, lie the complex of structures associated with the former organic fertilizer production facility.

Similar to KOP 1, views from KOP 2 are dominated by cultivated cropland in the foreground and middleground against the medium brown tones of the Elk Hills in distant middleground views. The edges of fields planted in orchards add slight variation in views to the west on either side of Stockdale Highway. The ridgeline of the Temblor Range is visible in the background to the west. Above-ground utility lines on wooden poles are visible along roadways and other rights-of-way in foreground and middleground views. Stockdale Highway is a two-lane blacktop roadway in the view at this location.

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[32] See **Visual Resources Figures 7a** and **7b**.

Similar to KOP 1, little variation is apparent in the form and line of landscape elements at KOP 2. No particular landscape feature or landform draws the viewer's attention. Visual quality for KOP 2 is characterized as moderate.
Viewers at or near KOP 2 include residents at two adjacent properties on the north side of Stockdale Highway directly behind (north of) the viewpoint for this photograph and motorists on Stockdale Highway. Other residential properties are near the viewpoint for KOP 2; one is near the intersection of Dairy Road and the highway, and the other is on Dunford Road north of the highway. Viewer concern for residents is considered high. Stockdale Highway is a major east-west thoroughfare that extends from State Route (SR) 99 in Bakersfield to the west side of the San Joaquin Valley. Truck traffic is a daily presence on the highway. It is assumed that other motorists include residents of the area and employees of businesses in the area. Motorists on the highway are expected to have moderately low viewer concern. For this combination of viewer groups, viewer concern is estimated to be moderate to moderately high.

Under existing conditions, views of the site are partially interrupted by the built structures at the organic fertilizer production facility. Because the project site is approximately 1½ miles southeast of the viewer from the viewpoint of KOP 2, and due to the presence of intervening built structures, visibility of the project site at this location is moderate to high.

Viewers for KOP 2 include motorists and residents. Traffic data compiled by Kern COG includes traffic counts for 2012 on Stockdale Highway west of the I-5 ramps. Traffic counts were considered in the estimate of number of viewers for KOP 2. As of April 12, 2011, the AADT volume at this location was approximately 1,494 (Kern COG 2012). The rating for number of viewers at KOP 2 is estimated to be moderately low. Viewer duration is considered high for residents with a direct view of the project site from KOP 2. Motorists on Stockdale Highway could be traveling close to highway speed or more slowly, depending on the habits of the drivers. Views of the project site from the highway would mostly be in the periphery of views for drivers heading east or west on the road, with views of the project site lasting from 10 to 20 seconds. For this viewer group, the rating for duration of view is considered low to moderate. For this combination of viewer groups, duration of view is estimated to be moderate to high.

Visibility of the project site from KOP 2 is moderate to high, and the number of viewers is moderately low. Duration of view is high for residents and low to moderate for motorists; the average duration of view is moderate to high. Therefore, based on the ratings for visibility, number of viewers, and duration of view, *overall viewer exposure* for KOP 2 is considered moderate. Visual quality is characterized as moderate. Viewer concern varies among the viewer groups; average viewer concern is moderate to moderately high. Therefore, based on the ratings for visual quality, viewer concern, and overall viewer exposure, *overall visual sensitivity* is considered moderate.

<u>Visual Change</u>

The visual simulation for KOP 2 shows the proposed project site as it would appear for a stationary viewer along Stockdale Highway between Dairy Road and Dunford Road. The closest HECA project structures would be approximately 1.75 miles southeast of the viewer in the middleground. Some of the tallest structures at the new plant site would be visible above the ridgeline of the Elk Hills in the far middleground.

Implementation of the HECA project and development of the site would introduce a moderate to high degree of contrast into the VSOI. The low profile and basic horizontal forms and lines of the existing landscape would be interrupted by the height and complexity of the structures that would be erected at the plant site. The uniformity of shapes and evenness of landforms created by the existing landscape for KOP 2 indicates low VAC for the view.

The distance to the project site from the viewpoint of KOP 2 would temper the color contrast created by the gray tones and steel surfaces of the proposed structures, however, the hard surfaces of the constructed project components would contrast notably with the relatively soft textures of the existing natural surfaces of the earth and vegetation. The level of visual contrast that would be created by construction of the proposed project is considered moderate to high.

The photographic simulation shows the proportionate size of the HECA project structures as a whole relative to the existing natural and built features in the field of view for KOP 2. The existing structures at the former organic fertilizer production facility are noticeable at the center of the field of view. Although the addition of new built structures would increase the density and mass of structures in the center of the view, the new structures would not completely dominate the landscape due to their distance from the viewer, and dominance of the proposed project in the view is rated as moderate. The open views of the Elk Hills and Temblor Range in the distant middleground of the view would be blocked to a degree at this location. For KOP 2, view blockage that would be created by the project is considered moderate. Therefore, for KOP 2, the *overall visual change* would be moderate.

Visual Impact Determination

Overall visual sensitivity for KOP 2 is considered moderate and *overall visual change* is considered moderate. Energy Commission staff concludes that introducing the publicly visible project structures into the existing view at KOP 2 would not cause substantial degradation of the existing visual character of the site and its surroundings. Therefore, a less-than-significant impact to visual resources is identified for KOP 2. No mitigation is required.

KOP 3

Visual Sensitivity

KOP 3 was photographed from the play field at Elk Hills Elementary School in the community of Tupman.[33] The HECA project site is approximately 2.5 miles northwest of this viewpoint. The school site is situated at a slightly higher elevation than the valley floor, which allows for expansive views across the landscape from the campus. Foreground views north and northwest from KOP 3 include views of disturbed valley saltbush scrub and light-colored sandy soils. The property below and next to the play

[33] See **Visual Resources Figures 8a** and **8b**.

field is sometimes used by motorized vehicles, and tire tracks are visible in the area. Tupman Road and the California Aqueduct cross the area in the foreground. Above-ground utility lines on wooden poles parallel Tupman Road. The open space in the Reserve fills the middleground of the view to the north. Structures at the organic fertilizer production facility and the surrounding palm trees beyond the northwest corner of the HECA project site are partially visible on the horizon.

Foreground views at KOP 3 are characterized by sparse low-lying vegetation and open areas that have been altered by development and urban uses. No landscape feature or landform in the middleground or background of the view draws the viewer's attention from KOP 3. Visual quality for KOP 3 is characterized as moderately low.

Viewers at KOP 3 include elementary school staff, students, and families of students.[34] The play field is used intermittently during school recesses and sporting events. Recreational viewers engaged in or observing active sport activities are likely to be attentive to the on-site activity rather than the aesthetics of the environment. However, viewer concern for viewers at KOP 3 would still be considered high.

Views of the project site from this location are unimpeded. Because the project site is approximately 2½ miles northwest of the view from KOP 3, and features in the VSOI at that distance do not dominate the view, visibility of the project site at this location is low to moderate.

Approximately 75 students are enrolled at Elk Hills Elementary School. The rating for the number of viewers at KOP 3 is estimated to be moderate. This estimate accounts for staff and families of students who may be preset on the play field with the students.

Children and adults using the play field would have opportunities to view the project site for extended periods of time during recesses and sport events, therefore, viewer duration is considered high for KOP 3.

Visibility of the project site from KOP 3 is low to moderate, and the number of viewers is moderate. Due to the expected presence of students and staff on the play field for extended periods, duration of view is high. Therefore, based on the ratings for visibility, number of viewers, and duration of view, *overall viewer exposure* for KOP 3 is moderate. Visual quality is rated as moderately low and viewer concern is high. Therefore, based on the ratings for visual quality, viewer concern, and overall viewer exposure, *overall visual sensitivity* is considered moderate.

<u>Visual Change</u>

The visual simulation for KOP 3 shows the proposed project site as it would appear for a viewer from the play field at Elk Hills Elementary School. The closest HECA project structures would be approximately 2.5 miles northwest of the viewer in the far middleground.

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[34] See **Appendix VR-1**.

The low profile and evenness of landforms created by the existing landscape for KOP 3 indicates low VAC for the view. Although the bold, angular shapes of the new structures may draw the attention of viewers in the vicinity of KOP 3, the considerable distance to the project site from KOP 3 and the seasonal hazy atmosphere in the valley would subdue the effects of form, color, and textural contrast created by the inorganic surfaces that would define the structures at the project site. The degree of visual contrast that would be created by construction of the proposed project is considered moderate for KOP 3.

Although the addition of new built structures in the view for KOP 3 would increase the density and mass of structures in the center of the view, the new structures would not dominate the landscape due to their distance from the viewer, and dominance of the proposed project in the view is rated as moderate. For KOP 3, view blockage that would be created by the project is considered low to moderate. Therefore, for KOP 3, the *overall visual change* would be moderately low to moderate.

Visual Determination

Overall visual sensitivity for KOP 3 is considered moderate and *overall visual change* is considered moderately low to moderate. Energy Commission staff concludes that introducing the publicly visible structures into the existing view at KOP 3 would not cause substantial degradation of the existing visual character of the site and its surroundings. Therefore, a less-than-significant impact to visual resources is identified for KOP 3. No mitigation is required.

KOP 4

Visual Sensitivity

KOP 4 was photographed from the shoulder of the westbound lane of Stockdale Highway near the I-5 interchange.[35] The HECA project site is approximately 2.5 miles southwest of KOP 4.

Views to the west and southwest from KOP 4 are characterized by sparse low-lying vegetation, sandy loamy soils in the foreground, and open terrain extending from the foreground through the middleground. North and south trending high-voltage transmission lines extending between tall lattice towers are visible in distant foreground views from KOP 4. A few trees and isolated buildings and other structures are visible in views across the valley. The Elk Hills are outlined in the background. The area is characterized by little color variation. Similar to KOP 2, Stockdale Highway is a two-lane blacktop roadway in the view at KOP 4. The project site is visible to the southwest for motorists heading west on the highway.

The views at KOP 4 are typical of many areas in the San Joaquin Valley along the I-5 corridor. The transportation network and structures for various utilities overpower subtle variations in the form and line of landscape elements. No particular landscape feature or landform draws the viewer's attention. Visual quality for KOP 4 is characterized as low to moderate.

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[35] See **Visual Resources Figures 9a** and **9b**.

As described above, various types of trucks are regularly present on Stockdale Highway. Other motorists include residents of the area and employees of nearby businesses. No residences are located nearby, and most of the highway commercial development adjacent to this interchange is on the east side of I-5. As such, motorists on the highway are expected to have low to moderate viewer concern, depending on their preferences.

Under existing conditions, views of the HECA project site from KOP 4 are partially interrupted by the high-voltage transmission lines that cross the landscape. Because the project site is approximately 2½ miles southwest of the viewer from the viewpoint for KOP 4, and due to the presence of intervening built structures, visibility of the project site at this location is low to moderate.

Based on Kern COG data for 2012, the AADT volume on Stockdale Highway west of the I-5 ramps was approximately 1,277 (Kern COG 2012). The rating for number of viewers at KOP 4 is estimated to be moderately low.

Motorists on Stockdale Highway could be traveling at speeds over 45 miles per hour. Brief views of the project site from the highway would be possible for motorists heading west or east on the highway. It is estimated that views of the project site for this viewer group would last from 10 to 20 seconds. For this viewer group, the rating for duration of view is considered moderately low.

Visibility of the project site from KOP 4 is low to moderate. Number of viewers and duration of views are each rated as moderately low. Therefore, based on the ratings for these three variables, *overall viewer exposure* for KOP 4 is moderately low.
Visual quality is characterized as low to moderate. Viewer concern is rated low to moderate. Therefore, based on the ratings for visual quality, viewer concern, and overall viewer exposure, *overall visual sensitivity* for KOP 4 is also considered moderately low.

Visual Change

The visual simulation for KOP 4 shows the proposed project site as it would appear for a viewer from Stockdale Highway near I-5. The closest HECA project structures would be approximately 2.5 miles southwest of the viewer in the far middleground.

Although the angular, vertical shapes of the new structures may draw the attention of viewers in the vicinity of KOP 4, the considerable distance to the project site from this viewpoint and the atmospheric haze that is frequently present in the valley would subdue the effects of form, color, and textural contrast created by the inorganic surfaces of new structures at the project site. The degree of visual contrast that would be created by construction of the proposed project is considered low to moderate for KOP 4.

The photographic simulation shows the proportionate size of the HECA project structures as a whole relative to the existing features in the view for KOP 4. Although the addition of new built structures would increase the density and mass of structures in the center of the view, the new structures would not dominate the landscape due to their distance from the viewer and the existing high-voltage transmission lines that cross the foreground of the landscape between the viewpoint for KOP 4 and the project site. Dominance of the proposed project in the view is rated as low to moderate, and view blockage that would be created by the project is considered low to moderate. Therefore, for KOP 4, the *overall visual change* would be moderately low.

Visual Determination

Overall visual sensitivity for KOP 4 is considered moderately low and *overall visual change* is also considered moderately low. Energy Commission staff concludes that introducing the publicly visible structures into the existing view at KOP 4 would not cause substantial degradation of the existing visual character of the site and its surroundings. Therefore, a less-than-significant impact to visual resources is identified for KOP 4. No mitigation is required.

KOP 6

Visual Sensitivity

KOP 6 was photographed from the shoulder of the eastbound lane of Brite Road, approximately 1 mile east of Wasco Way.[36] The HECA project site is approximately 3 miles southeast of KOP 6.

Views to the southeast from KOP 6 are characterized by a relatively flat topography with sandy loamy soils in the foreground, and open terrain extending from the foreground through the middleground. In the background, there are a few above-ground utility lines on wooden poles are visible along roadways and isolated structures. The area is characterized by little color variation with mostly natural sparse and striated vegetation, and has a low to moderate contrast of generally flat tones. Brite Road is a two-lane blacktop roadway in the view at this location.

Little variation is apparent in the form and line of landscape elements at KOP 6. No particular landscape feature or landform draws the viewer's attention. Visual quality for KOP 6 is characterized as moderately low.

Viewers at or near KOP 6 includes two residences and motorists. The first residence is located at a property on the north side of Brite Road, northwest of the viewpoint for this photograph. The second residence is located at a property on the south side of Brite Road, directly west of the viewpoint for this photograph. Other residential properties are located near the viewpoint for KOP 6. One property is located on the north side of Brite Road, approximately 800 feet east of the first residential property mentioned above. Viewer concern for residents is considered high. Motorists using local roadways include employees of agricultural, oil production, and other businesses whose focus is on their travels and daily pursuits. Motorists on the highway are expected to have low to moderate viewer concern. For this combination of viewer groups, viewer concern is estimated to be moderate to moderately high.

Under existing conditions, views of the site are partially interrupted by the built structures at the organic fertilizer production facility. Because the project site is

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[36] See **Visual Resources Figures 10a** and **10b**.

approximately 3 miles southeast of the viewer from the viewpoint of KOP 6, and due to the presence of intervening built structures, visibility of the project site at this location is moderate to moderately high.

Viewers for KOP 6 include motorists and residents. Traffic data compiled by Kern COG includes traffic counts for 2012 on Brite Road and Mirasol Avenue. Traffic counts were considered in the estimate of number of viewers for KOP 6. As of August 1, 2012, the AADT volume at this location was approximately 920 (Kern COG 2012). The rating for number of viewers at KOP 6 is estimated to be moderately low.

Viewer duration is considered high for residents with a direct view of the project site from KOP 6. Motorists on Brite Road would be traveling at relatively low speeds and may have views of the project site lasting from 20 to 60 seconds. For this viewer group, the rating for duration of view is considered moderate. For this combination of viewer groups, duration of view is estimated to be moderate to high.

Visibility of the project site from KOP 6 is moderate to moderately high, and the number of viewers is moderately low. Duration of view is high for residents and low to moderate for motorists; the average duration of view is moderate to high. Based on the ratings for visibility, number of viewers, and duration of view, *overall viewer exposure* for KOP 6 is considered moderate.

Visual quality is characterized as moderately low. Viewer concern varies among the viewer groups; average viewer concern is moderate to moderately high. Therefore, based on the ratings for visual quality, viewer concern, and overall viewer exposure, *overall visual sensitivity* is considered moderate.

Visual Change

The visual simulation for KOP 6 shows the proposed project site as it would appear for a stationary viewer along the eastbound lane of Brite Road, approximately 1 mile east of Wasco Way. The closest HECA project structures would be approximately 3 miles southeast of the viewer in the far middleground.

Implementation of the HECA project and development of the site would introduce a moderate to high degree of contrast into the VSOI. The low profile and basic horizontal forms and lines of the existing landscape would be interrupted by the height and complexity of the structures that would be erected at the plant site. The uniformity of shapes and evenness of landforms created by the existing landscape for KOP 6 indicates low VAC for the view.

The distance to the project site from the viewpoint of KOP 6 would temper the color contrast created by the gray tones and steel surfaces of the proposed structures, however, the hard surfaces of the constructed project components would contrast notably with the relatively soft textures of the existing natural surfaces of the earth and vegetation. The level of visual contrast that would be created by construction of the proposed project is considered moderate to high.

The photographic simulation shows the proportionate size of the HECA project structures as a whole relative to the existing natural and built features in the field of view for KOP 6. The existing structures at the former organic fertilizer production facility are slightly noticeable at the right of the field of view. There is an existing residential structure that is noticeable at the center of the view and several others at the left of the view that are only somewhat noticeable. Although the addition of new built structures would increase the density and mass of structures on the right of the view, the new structures would not completely dominate the landscape due to their distance from the viewer and other existing (residential) structures in the same view. As such, dominance of the proposed project in the view is rated as low to moderate. Due to the distance between KOP 6 and the project site, there are no open views of the Elk Hills or Temblor Range in the background. As such, for KOP 6, view blockage that would be created by the project is considered low to moderate. Therefore, for KOP 6, the *overall visual change* would be moderately low to moderate.

Visual Impact Discussion

Overall visual sensitivity for KOP 6 is considered moderately low to moderate and *overall visual change* is also considered moderate. Energy Commission staff concludes that introducing the publicly visible structures into the existing view at KOP 6 would not cause substantial degradation of the existing visual character of the site and its surroundings. Therefore, a less-than-significant impact to visual resources is identified for KOP 6. No mitigation is required.

Visual Character and Quality – Conclusion (HECA)

Energy Commission staff evaluated the proposed project's effects on visual resources at the six selected KOPs. The visual impact determinations are focused on the overall visual sensitivity for each KOP and whether the HECA project would cause substantial degradation of the existing visual character of the site and its surroundings.

Staff determined that the impacts at KOP 2, KOP 3, KOP 4, and KOP 6 did not meet or exceed the criterion set forth in the discussion above. Therefore, the project would not cause substantial degradation of the existing visual character of the site and its surroundings at these four KOPs. However, as the project would cause substantial degradation of the existing visual character of the site and its surroundings at KOP 1, a significant impact to visual resources is identified at KOP 1.

VISIBLE WATER VAPOR PLUMES

HRSG Stack

Publicly visible water vapor plumes that would emit from the HRSG would vary in frequency and size depending on whether the fuel source is hydrogen rich fuel or natural gas and if duct firing is occurring or not. As shown below in **Visual Resources Table 6**, plume frequency during seasonal daylight clear hours would not exceed 20 percent for the operation with duct firing.[37]

[37] See Table 11 in **Appendix VR-2**.

Visual Resources Table 6
Plume Frequency for the HRSG

Fuel Type	Plume Frequency Percent with Duct Firing	Plume Frequency Percent with No Duct Firing
Hydrogen Rich Fuel	9%	4%

Source: Energy Commission Staff 2010

Since the plume frequency is below 20% of seasonal daylight clear hours for the operation with and without duct firing, the corresponding plume dimensions have not been included.

Air Separation Unit Cooling Tower

Publicly visible water vapor plumes from the ASU cooling tower are predicted to occur approximately 37 percent of the time during seasonal daylight clear hours.[38] Because the plume frequency would exceed 20 percent, Energy Commission staff calculated (modeled) the 20th percentile plume dimensions using the combustion stack visible plume (CSVP) model. For the ASU cooling tower, the 20th percentile plume dimensions are predicted to be approximately 276 feet high, 142 feet in length, and 78 feet wide.[39] Because the cooling tower structure would be 55 feet tall, the visible plume above the cooling tower would be approximately 221 feet tall.

13-Cell Power Block Cooling Tower

Publicly visible water vapor plumes from the 13-cell power block cooling tower are predicted to occur approximately 37 percent of the time during seasonal daylight clear hours.[40] Because the plume frequency exceeds 20 percent, staff modeled the 20th percentile plume dimensions. For the 13-cell power block cooling tower, the 20th percentile plume dimensions are predicted to be approximately 393 feet high, 352 feet in length, and 186 feet wide.[41] Because the cooling tower structure would be 55 feet tall, the visible plume above the cooling tower would be approximately 338 feet tall.

Coal Dryer Stack

Publicly visible water vapor plumes from the coal dryer are predicted to occur approximately 40 percent of the time during seasonal daylight clear hours.[42] Because the plume frequency exceeds 20 percent, staff modeled the 20th percentile plume dimensions. For the coal dryer, the 20th percentile plume dimensions are predicted to be approximately 554 feet high, 132 feet in length, and 73 feet wide.[43] Because the cooling tower structure would be 305 feet tall, the visible plume above the cooling tower would be approximately 249 feet tall.

[38] See Table 2 in **Appendix VR-2**.
[39] See Table 3 in **Appendix VR-2**.
[40] See Table 7 in **Appendix VR-2**.
[41] See Table 8 in **Appendix VR-2**.
[42] See Table 13 in **Appendix VR-2**.
[43] See Table 14 in **Appendix VR-2**.

Conclusion for Effects Relating to the Water Vapor Plumes[44]

Publicly visible water vapor plumes for the project's ASU cooling tower, the 13-cell power block cooling tower, and coal dryer stack are predicted to occur more than 20 percent of the time during seasonal daylight clear hours. As such, the visual resources analysis below addresses the worst-case maximum facility operating condition for each of these three structures.

Visual Resources Table 1 shows the dimensions of proposed structures at the project site. Many of the structures would be at least 100 feet tall, and several would be over 200 feet tall. The overall mass of the built structures would dominate views of the project site relative to the water vapor plumes. Plumes emanating from the proposed project's ASU cooling tower, 13-cell power block cooling tower, and coal dryer are predicted to be relatively small and visually subordinate to the permanent structures that would be installed at the project site. Energy Commission staff concludes that the magnitude of the change to visual resources from introduction of water vapor plumes into the project VSOI would not substantially degrade the existing visual character or quality of the site and its surroundings. Therefore, staff considers publicly visible water vapor plumes to be a less-than-significant impact of the project. No mitigation is required.

The ground fogging plume analysis predicts that ground fogging plumes from the proposed process cooling tower and power block cooling tower would not reach any of the nearby roads. Therefore, staff considers publicly visible ground fogging plumes to be a less-than-significant impact of the project. No mitigation is required.

ELECTRICAL TRANSMISSION LINE

Installation of the proposed transmission line and tangent structures would increase overhead utility lines near the project area. The tangent and dead-end structures supporting the lines would stand 90 to 106 feet tall and 115 feet tall, respectively. Most publicly visible areas in the project VSOI include views of various above-ground utility lines along local roadways and other utility corridors. The addition of the new transmission line would augment the existing condition for visible utility lines.
Several residences are located within approximately 2,000 feet of the route for the proposed transmission line.[45] Viewer concern for residents who would have views of the transmission line is expected to be high. Depending on the angle of view and the presence of existing screening (e.g., mature trees), the poles could be highly visible from viewpoints at and near local residences. Viewer concern for visitors to the Tule Elk Reserve State Park is considered moderate to high. These viewers may have unobstructed views of the transmission line from the Reserve.

Although viewer concern is high or moderate to high, overhead utility lines are a common visual element in the project area, and, when compared to the existing condition, the change to the visual environment from construction of the transmission

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[44] Please refer to the Air Quality section of this staff assessment for a discussion of the potential visibility impacts of the proposed project relating to gaseous emissions.

[45] See **Visual Resources Table 4**.

line would not be substantial. Therefore, Energy Commission staff concludes that introducing the transmission line and pole structures into the visual environment near the project site would be a less-than-significant impact of the project. No mitigation is required.

RAILROAD SPUR

Construction of the railroad spur would introduce railcars into the VSOI. Rail deliveries would either be delivered directly to the project site via a railroad spur or be off-loaded and transported by a specialized heavy-haul contractor near Buttonwillow to the project site. Because the railroad spur would be constructed on the ground plane, this feature is not expected to result in visual contrast. Rail traffic would be visible from locations south of the community of Buttonwillow. According to the applicant, the HECA facility would operate 24 hours/day and 333 days/year.[46] Within a given 24-hour operational period, there would be a total of three on-site trains (one coal train and two product trains).[47] Under normal daily operations, each train would contain a total of approximately 57 railcars.[48] Under maximum daily operations, each train would contain a total of 242 rail cars.[49] However, each coal train and product train would take approximately two hours and one hour, respectively, to load/unload its cargo.[50] As such, it is likely that any views of trains within the VSOI would be intermittent, temporary, and potentially negligible (as train traffic could occur at night). Therefore, Energy Commission staff concludes that introducing the railroad spur into the VSOI would be a less-than-significant impact. No mitigation is required.

CONSTRUCTION-RELATED EFFECTS

The presence and movement of heavy construction equipment and construction-related generation of dust would have the potential to temporarily degrade the existing visual character and quality of views in the project VSOI. Viewer groups in the project construction areas include motorists on local roadways and highways, occupants of rural residences, employees of businesses in the area, and recreationists. Residents and recreationists are considered to have the highest viewer concern of these viewer groups.

Although construction would occur over a 49-month construction period, the work would be phased and often limited to particular types of activities or areas within the whole site. Although construction activities during a particular construction phase could be clearly visible from several viewpoints in the project VSOI, the work would be relatively short term and temporary in nature. Changes in visual resources conditions would occur along segments of pipelines and the transmission line alignment as construction progressed and continued through the area. Energy Commission staff concludes that the temporary nature of construction activities at the project site and along linear facilities would not cause substantial degradation of the existing visual character or

[46] See **Amended AFC for HECA - Air Quality Table 5.1-19**.
[47] *Ibid*.
[48] See **Amended AFC for HECA** - **Appendix E-3: Air Quality**, page 24.
[49] *Ibid*.
[50] *Ibid*, page 30.

quality of the site and its surroundings. Therefore, construction-related impacts are considered less-than-significant. No mitigation is required.

OEHI

KEY OBSERVATION POINTS – OEHI

Visual Resources Figure 2 shows the locations of the six KOPs used for this analysis:

- KOP 1 – View of the OEHI site, looking north-northwest from the intersection of Highway 119 and Golf Course Road;
- KOP 2 – View of the OEHI site, looking north from the intersection of Highway 119 and Tank Farm Road;
- KOP 3 – View of the OEHI site, looking north from Airport Road;
- KOP 4 – View of the OEHI site, looking northwest from Elk Hills Road;
- KOP 5 – View of the OEHI site, looking southwest from Grace Avenue; and
- KOP 6 – View of the OEHI site, looking south-southwest from the U.S. Post Office.[51]

KOP 1[52]

Visual Sensitivity

KOP 1 was photographed from the shoulder of the westbound lane of Golf Course Road, at the intersection of Golf Course Road and Highway 119.[53] The OEHI component is approximately 3 miles north-northeast of KOP 1.

Views to the north-northeast from KOP 1 are characterized by Highway 119 and telephone poles in the foreground and the relatively undisturbed scrub covered base of the Elk Hills through the middleground. In the background are the Elk Hills. The area is characterized by little color variation with sparse shrub vegetation. Highway 119 is a two-lane blacktop roadway in the view at this location.

Little variation is apparent in the form and line of landscape elements at KOP 1. No particular landscape feature or landform draws the viewer's attention. Visual quality for KOP 1 is characterized as moderately low to moderate.

Viewers at or near KOP 1 include several residents and motorists. The first four residences are located to the south of Golf Course Road, near the intersection of Golf Course Road and Highway 119. The second residence is located at a property on the north side of Golf Course Road, near the intersection of Golf Course Road and Highway 119. Other residential properties are located near the viewpoint for KOP 1. Viewer

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[51] The U.S. Post Office is located at 337 Emmons Boulevard Tupman, CA 93276.

[52] The following references made to distances/cardinal directions between the OEHI component and KOP 1, are in regards to the CO_2 EOR Processing Facility, as this would be the most prominent/visible element of the OEHI site.

[53] See **Visual Resources Figures 11a** and **11b**.

concern for residents is considered high. Motorists using local roadways include local residents, employees of oil and gas production, gravel mining, and other businesses whose focus is on their travels and daily pursuits. Motorists on the highway are expected to have low to moderate viewer concern. For this combination of viewer groups, viewer concern is estimated to be moderate to moderately high.

Under existing conditions, views of the project site are only slightly interrupted by two street signs and three telephone poles. However, because the project site is approximately 3 miles north-northeast of the viewer from the viewpoint of KOP 1, and small intervening built structures are also in the VSOI, visibility of the project site at this location is low to moderate.

Viewers for KOP 1 include motorists and residents. Traffic data compiled by Kern COG includes traffic counts for 2012 on Golf Course Road and Highway 119. Traffic counts were considered in the estimate of number of viewers for KOP 1. As of August 1, 2012, the AADT volume at this location was approximately 800 (Kern COG 2012). The rating for number of viewers at KOP 1 is estimated to be moderately low.

Viewer duration is considered high for residents with a direct view of the project site from KOP 1. Motorists on Highway 119 could be traveling close to highway speed or more slowly, depending on the habits of the drivers. Views of the project site from Highway 119 would mostly be in the periphery of views for drivers heading southwest or northeast on the road, with views of the project site lasting from 10 to 20 seconds. For this viewer group, the rating for duration of view is considered low to moderate. For this combination of viewer groups, duration of view is estimated to be moderate to moderately high.

Visibility of the project site from KOP 1 is low to moderate, and the number of viewers is moderately low. Duration of view is high for residents and low to moderate for motorists; the average duration of view is moderate to moderately high. Based on the ratings for visibility, number of viewers, and duration of view, overall viewer exposure for KOP 1 is considered moderately low to moderate.

Visual quality is characterized as moderately low to moderate. Viewer concern varies among the viewer groups; average viewer concern is moderate to moderately high. Based on the ratings for visual quality, viewer concern, and overall viewer exposure, overall visual sensitivity is considered moderately low to moderate.

Visual Change

For KOP 1, the far middle ground and background topography would limit most, if not virtually all, views of any proposed project elements both during construction and operations. Therefore, for KOP 1, the *overall visual change* would be low.

Visual Impact Discussion

Overall visual sensitivity for KOP 1 is considered moderately low to moderate and *overall visual change* is considered low. Energy Commission staff concludes that introducing the publicly visible project structures into the existing view at KOP 1 would not cause substantial degradation of the existing visual character of the site and its surroundings. Therefore, a less-than-significant impact to visual resources is identified for KOP 1. No mitigation is required.

KOP 2[54]

Visual Sensitivity

KOP 2 was photographed from the shoulder of the westbound lane of Golf Course Road, at the north side of the intersection of Tank Farm Road and Highway 119.[55] The OEHI site is approximately 3 miles north of KOP 2.

Views to the north from KOP 2 are characterized by relatively flat visually intact grasslands with sparse shrub vegetation extending from the foreground to the middle ground. In the middle ground, approximately one-mile away, aboveground sections of a pipeline can be seen as a dark weathered-steel line contrast against the tan colored grasses. In the background are the Elk Hills and EHOF with evidence of significant topographic disturbance from roadway cuts and the cut/fill slopes of engineered pads for buildings and extraction equipment. On the horizon are many tall vertical structures such as derricks, power poles, communication towers, etc.

Due to some of the EHOF structures in the background, some variation is apparent in the form and line of landscape elements at KOP 2. However, no particular landscape feature or landform draws the viewer's attention. Therefore, the visual quality for KOP 2 is characterized as low to moderately low.

Viewers at or near KOP 2 include several residents and motorists. Residents on both the east (abutting Tank Farm Road) and west (abutting Sun Ridge Avenue) of Highway 119 would have views of the project site. Viewer concern for residents is considered high. Motorists using local roadways include employees of oil and gas production, gravel mining, and other businesses whose focus is on their travels and daily pursuits. Motorists on the highway are expected to have low to moderate viewer concern. For this combination of viewer groups, viewer concern is estimated to be moderate to moderately high.

Under existing conditions, views of the project site are slightly interrupted by the pipeline and other vertical built structures mentioned above. However, visibility of these structures is lessened due to their relatively far distance to KOP 2 (2.5-3 miles). Therefore, visibility of the project site at this location is low to moderate.

Viewers for KOP 2 include motorists and residents. Traffic data compiled by Kern COG includes traffic counts for 2012 on Tank Farm Road and Highway 119. Traffic counts were considered in the estimate of number of viewers for KOP 2. As of August 1, 2012, the AADT volume at this location was approximately 65 (Kern COG 2012). The rating for number of viewers at KOP 2 is estimated to be low.

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[54] The following references made to distances/cardinal directions between the OEHI component and KOP 2, are in regards to the CO_2 EOR Processing Facility, as this would be the most prominent/visible element of the OEHI site.

[55] See **Visual Resources Figures 12a** and **12b**.

Viewer duration is considered high for residents with a direct view of the project site from KOP 2. Motorists on Highway 119 could be traveling close to highway speed or more slowly, depending on the habits of the drivers. Motorists on Tank Farm Road (or Sun Ridge Avenue) could be traveling at a more moderate speed, depending on the habits of the drivers. Views of the project site from Highway 119 would mostly be in the periphery of views for drivers heading southwest or northeast on the road, with views of the project site lasting from 10 to 20 seconds. Views of the project site from Tank Farm Road (or Sun Ridge Avenue) would mostly be in the periphery of views for drivers heading west or east on the road(s), with views of the project site lasting from 20 to 60 seconds. For this viewer group, the rating for duration of view is considered moderate. For this combination of viewer groups, duration of view is estimated to be moderately high.

Visibility of the project site from KOP 2 is low to moderate, and the number of viewers is low. Duration of view is high for residents and moderate for motorists; the average duration of view is moderately high. Based on the ratings for visibility, number of viewers, and duration of view, *overall viewer exposure* for KOP 2 is considered moderately low.

Visual quality is characterized as moderately low. Viewer concern varies among the viewer groups; average viewer concern is moderate to moderately high. Based on the ratings for visual quality, viewer concern, and overall viewer exposure, *overall visual sensitivity* is considered moderately low to moderate.

Visual Change

For KOP 2, some proposed pipeline installation areas would be visible from SR 119 and Tank Farm Road and present a visual change to the VSOI. However, a majority of the pipelines would run parallel to an existing pipeline in the middle ground of this KOP. Further, most of the proposed project components would be replacing existing oil extraction equipment (Occidental of Elk Hills 2012). Thus, it is likely that the pipeline installation areas which would be visible from KOP 2 would offer little contrast, dominance or view blockage to the existing VSOI. Therefore, for KOP 2, the *overall visual change* would be moderately low.

Visual Impact Determination

Overall visual sensitivity for KOP 2 is considered moderately low and *overall visual change* is considered moderately low to moderate. Energy Commission staff concludes that introducing the publicly visible project structures into the existing view at KOP 2 would not cause substantial degradation of the existing visual character of the site and its surroundings. Therefore, a less-than-significant impact to visual resources is identified for KOP 2. No mitigation is required.

KOP 3[56]

<u>Visual Sensitivity</u>

KOP 3 was photographed from Airport Road looking north.[57] The OEHI site is approximately 5.5 miles north of KOP 3.

Views to the north from KOP 3 are characterized by a dirt/gravel road and telephone poles in the immediate foreground. Views extending from the foreground to the middle ground are characterized by relatively flat visually intact grasslands with sparse shrub vegetation. In the far middle ground there is a substantial collection of large white cylindrical tanks used for oil separation. In the background are the Elk Hills and EHOF with evidence of significant topographic disturbance from roadway cuts and the cut/fill slopes of engineered pads for buildings and extraction equipment. On the horizon are many tall vertical structures such as derricks, power poles, communication towers, etc.

Due to the road, telephone poles, collection of large white cylindrical tanks, etc. some variation is apparent in the form and line of landscape elements at KOP 3. However, no particular landscape feature or landform draws the viewer's attention. Therefore, the visual quality for KOP 3 is characterized as low to moderately low.

Viewers at or near KOP 3 include motorists. Motorists using local roadways include employees of oil and gas production, gravel mining, and other businesses whose focus is on their travels and daily pursuits. Motorists on the highway are expected to have low to moderate viewer concern.

Under existing conditions, views of the project site are interrupted by the road, telephone poles, collection of large white cylindrical tanks, and other vertical built structures mentioned above. However, visibility of the background structures is lessened due to their relatively far distance to KOP 3 (3-3.5 miles). However, it remains apparent that man-made alterations have been made in the immediate area. Therefore, visibility of the project site at this location is moderately low to moderate.

Viewers for KOP 3 include motorists. Traffic data compiled by Kern COG includes traffic counts for 2012 on Airport Road, east of Highway 119. Traffic counts were considered in the estimate of number of viewers for KOP 3. As of August 1, 2012, the AADT volume at this location was approximately 750 (Kern COG 2012). The rating for number of viewers at KOP 3 is estimated to be moderately low.

Motorists on Airport Road would likely be traveling at lower than highway speeds, as the road shown in KOP 3 is unpaved. Views of the project site from Airport Road would include frontal and peripheral views, with views of the project site lasting from 1 to 2 minutes or longer. For this viewer group, the rating for duration of view is considered moderate to high.

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[56] The following references made to distances/cardinal directions between the OEHI component and KOP 3, are in regards to the CO_2 EOR Processing Facility, as this would be the most prominent/visible element of the OEHI site.

[57] See **Visual Resources Figures 13a** and **13b**.

Visibility of the project site from KOP 3 is moderately low to moderate, and the number of viewers is moderately low. Duration of view is moderate to high for motorists. Based on the ratings for visibility, number of viewers, and duration of view, *overall viewer exposure* for KOP 3 is considered moderately low to moderate.

Visual quality is characterized as low to moderately low. Viewer concern is low to moderate. Based on the ratings for visual quality, viewer concern, and overall viewer exposure, *overall visual sensitivity* is considered moderately low.

Visual Change

For KOP 3, some proposed pipeline installation areas would introduce a visual change into the VSOI. Further, in the distant background, new and upgraded equipment may be partially visible in addition to one or more of the new satellite facilities. However, a majority of the proposed pipeline length would run parallel to an existing pipeline in the middle ground of this KOP. This existing pipeline which runs at grade above-ground through the middle ground of this KOP is not visible due to the dense shrub vegetation. Thus, it is likely that the pipeline installation areas which would be visible from KOP 3 would offer little contrast, dominance or view blockage to the existing VSOI. Therefore, for KOP 3, the *overall visual change* would be moderately low.

Visual Impact Determination

Overall visual sensitivity for KOP 3 is considered moderately low to moderate and *overall visual change* is considered moderately low. Energy Commission staff concludes that introducing the publicly visible project structures into the existing view at this KOP would not cause substantial degradation of the existing visual character of the site and its surroundings. Therefore, a less-than-significant impact to visual resources is identified for KOP 3. No mitigation is required.

KOP 4

Visual Sensitivity

KOP 4 was photographed along Elk Hills Road looking west-northwest.[58] KOP 4 is located within the EHOF, approximately 5 miles west-northwest of the proposed CO_2 Processing Facility.

Views to the north from KOP 4 are characterized by fence lines, unpaved roadways, and utility poles in the immediate foreground. Views extending from the foreground to the middle ground include an existing pipeline that passes under Elk Hills Road and extends to a white cylindrical tower. In the far middle ground exists views of the Elk Hills, which include several unpaved roadways, engineering pads, and power poles. Views of the Elk Hills continue into the background and include a few derricks and power poles up against the ridgeline. Views of the Temblor Range can be seen in the distant background.

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[58] See **Visual Resources Figures 14a** and **14b**.

Due to the fence lines, roads (paved and unpaved), power poles, pipeline, pads, white cylindrical tanks, and other built structures, etc. some variation is apparent in the form and line of landscape elements at KOP 4. However, no particular landscape feature or landform draws the viewer's attention. Therefore, the visual quality for KOP 4 is characterized as low to moderately low.

As KOP 4 is located within the EHOF boundaries, viewers at or near KOP 4 would be motorists. Motorists using local roadways include employees of oil and gas production, gravel mining, and other businesses whose focus is on their travels and daily pursuits. Motorists on the highway are expected to have low to moderate viewer concern.

Under existing conditions, views of the project site are interrupted by man-made alterations, including: fence lines, a paved two-lane road, unpaved roads, power poles, pipeline, pads, white cylindrical tanks, and other built structures. Therefore, visibility of the project site at this location is moderate.

Viewers for KOP 4 include motorists. Traffic data compiled by Kern COG includes traffic counts for 2012 on Elk Hills Road, north of Skyline Road. Traffic counts were considered in the estimate of number of viewers for KOP 4. As of August 1, 2012, the AADT volume at this location was approximately 1200 (Kern COG 2012). The rating for number of viewers at KOP 4 is estimated to be moderately low.

Motorists on Elk Hills Road could be traveling close to highway speed or more slowly, depending on the habits of the drivers. Views of the project site from Elk Hills Road would mostly be in the periphery of views for drivers heading north-northwest, with views of the project site likely lasting from 20 to 60 seconds. For this viewer group duration of view is estimated to be moderate.

Visibility of the project site from KOP 4 is moderate, and the number of viewers is moderately low. Duration of view for motorists is moderate. Based on the ratings for visibility, number of viewers, and duration of view, *overall viewer exposure* for KOP 4 is considered moderately low to moderate.

Visual quality is characterized as low to moderately low. Viewer concern is low to moderate. Based on the ratings for visual quality, viewer concern, and overall viewer exposure, *overall visual sensitivity* is considered moderately low.

<u>Visual Change</u>

For KOP 4, the only visual change introduced into the VSOI would be the alterations required during the construction of, and before reestablishment of, vegetation near the pipeline mentioned above. The pipeline would follow the alignment of the existing pipeline under the roadway and, subsequently, proceed along a new alignment across the hillsides. Although the middle ground view would be substantially altered, an effort would be made to align the pipeline adjacent to existing alterations, such as the existing roadways. Further, from KOP 4, the far middle ground and background topography would limit most, if not virtually all, views of any proposed project elements in the northwest portion of the project site both during construction and operations. It is likely that the vegetation and pipeline which would be visible from KOP 4 would offer little contrast, dominance or view blockage to the existing VSOI. Therefore, for KOP 4, the *overall visual change* would be moderately low.

Visual Impact Determination

Overall visual sensitivity for KOP 4 is considered moderately low and *overall visual change* is considered moderately low. Energy Commission staff concludes that introducing the publicly visible project structures into the existing view at this KOP would not cause substantial degradation of the existing visual character of the site and its surroundings. Therefore, a less-than-significant impact to visual resources is identified for KOP 4. No mitigation is required.

KOP 5[59]

Visual Sensitivity

KOP 5 was photographed along Grace Avenue and Elk Hills Elementary looking southwest to the OEHI site.[60] Views to the southwest from KOP 5 are characterized by a chain-link fence in the immediate foreground. The view extending from the foreground to the middle ground consists of the grass covered topography of the Elk Hills. The distant middle ground and background views are of the higher elevations of the Elk Hills, which have been substantially altered by decades of oil production operations. Large undeveloped areas are divided by unpaved roads and steep cut-fill slopes anchor industrial buildings and various configurations of extraction machinery. The dark profiles of these man-made elements project above the horizon line in contrast to the sky beyond.

Due to the fence, unpaved roads, extraction equipment, and other built structures, etc. some variation is apparent in the form and line of landscape elements at KOP 5. However, no particular landscape feature or landform draws the viewer's attention. Therefore, the visual quality for KOP 5 is characterized as low to moderately low.

Viewers at KOP 5 include elementary school staff, students, and families of students. The play field is used intermittently during school recesses and sporting events. Recreational viewers engaged in or observing active sport activities are likely to be attentive to the on-site activity rather than the aesthetics of the environment. However, viewer concern for viewers at KOP 5 would still be considered high.

Additionally, viewers at or near KOP 5 include residents and motorists. Residents with open southwest views from Kern Street and Grace Street would likely have views of the project site (particularly the CO_2 EOR Processing Facility). Viewer concern for residents is considered high. Motorists using local roadways include local residents, employees of oil and gas production, gravel mining, and other businesses whose focus is on their travels and daily pursuits. Due to the relatively short distances of nearby streets,

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[59] The following references made to distances/cardinal directions between the OEHI component and KOP 5, are in regards to the CO_2 EOR Processing Facility, as this would be the most prominent/visible element of the OEHI site.

[60] See **Visual Resources Figures 15a** and **15b**.

viewers are expected to have moderate viewer concern. For this combination of viewer groups, viewer concern is estimated to be moderately high.

Under existing conditions, views of the project site are only slightly obstructed by a chain-link fence. Furthermore, KOP 5 is approximately 1.5 miles from the project site. Therefore, visibility of the project site at this location is moderate to moderately high.

Viewers for KOP 5 include motorists. Traffic data compiled by Kern COG includes traffic counts for 2012 on Tupman Road, north of Taft Highway.[61] Traffic counts were considered in the estimate of number of viewers for KOP 5. As of August 1, 2012, the AADT volume at this location was approximately 690 (Kern COG 2012). The rating for number of viewers at KOP 5 is estimated to be moderately low.

Motorists on Grace Avenue would likely be traveling at residential speeds, depending on the habits of the drivers. Views of the project site from Tupman Road would mostly be in the periphery of views for drivers heading southwest, with views of the project site likely lasting from 10 to 20 seconds. For this viewer group duration of view is estimated to be moderately low.

Visibility of the project site from KOP 5 is moderate to moderately high, and the number of viewers is moderately low. Duration of view for motorists is moderately low. Based on the ratings for visibility, number of viewers, and duration of view, *overall viewer exposure* for KOP 5 is considered moderately low to moderate.

Visual quality is characterized as low to moderately low. Viewer concern is moderately high. Based on the ratings for visual quality, viewer concern, and overall viewer exposure, *overall visual sensitivity* is considered moderately low to moderate.

<u>Visual Change</u>

For KOP 5, the most prominent visual change introduced into the VSOI would be the proposed CO_2 EOR Processing Facility. Relative to the six KOPs, viewers at KOP 5 would have the clearest, least obstructed view of the Facility. The following Facility components would be visible from KOP 5, including: rooflines of the Administration/Control building and the Compressor Shelter (CRP) and the tops of the CO_2 Absorber, NGL Stabilizer, De-methanizer, and Flare Stack structures. Due to the up-slope view of the facility from KOP 5 and surrounding topography, visibility of the above mentioned components would be limited. However, due to the size and magnitude of the Facility structures, it is likely that the Facility would offer some contrast, dominance or view blockage to the existing VSOI. Therefore, for KOP 5, the *overall visual change* would be moderate.

<u>Visual Impact Determination</u>

Overall visual sensitivity for KOP 5 is considered moderately low to moderate and *overall visual change* is considered moderate. Energy Commission staff concludes that introducing the publicly visible project structures into the existing view at this KOP would not cause substantial degradation of the existing visual character of the site and its

[61] The closest AADT volume count to Grace Avenue is Tupman Road, north of Taft Highway.

surroundings. Therefore, a less-than-significant impact to visual resources is identified for KOP 5. No mitigation is required.

KOP 6[62]

Visual Sensitivity

KOP 6 was photographed just south of the U.S. Post Office looking southwest to the OEHI site.[63] Views to the southwest from KOP 6 are characterized by a chain-link fence in the immediate foreground. The view extending from the foreground to the middle ground consists of relatively flat visually intact grasslands with low to no shrub vegetation. The far middle ground and background are very similar to KOP 6; however, some middle ground topography partially screens these views.

Due to the fence, unpaved roads, extraction equipment, and other built structures, etc. some variation is apparent in the form and line of landscape elements at KOP 6. However, no particular landscape feature or landform draws the viewer's attention. Therefore, the visual quality for KOP 6 is characterized as low to moderately low.

Viewers at or near KOP 6 include residents and motorists. Residents with open southwest views from near the U.S. Post Office would likely have views of the project site. Viewer concern for residents is considered high. Motorists using local roadways include local residents, employees of oil and gas production, gravel mining, and other businesses whose focus is on their travels and daily pursuits. Due to the relatively short distances of nearby streets, viewers are expected to have low to moderate viewer concern. For this combination of viewer groups, viewer concern is estimated to be moderate to moderately high.

Under existing conditions, views of the project site are only slightly obstructed by a chain-link fence. Further, some middle ground topography partially screens these views. Therefore, visibility of the project site at this location is moderately low.

Viewers for KOP 6 include motorists. Traffic data compiled by Kern COG does not include traffic counts for 2012 on Emmons Boulevard. Traffic data compiled by Kern COG includes traffic counts for 2012 on Tupman Road, north of Taft Highway.[64] Traffic counts were considered in the estimate of number of viewers for KOP 6. As of August 1, 2012, the AADT volume at this location was approximately 690 (Kern COG 2012). The rating for number of viewers at KOP 6 is estimated to be moderately low.

Motorists near the U.S. Post Office would likely be traveling at residential speeds, depending on the habits of the drivers. Views of the project site from the U.S. Post Office would mostly be in the periphery of views for drivers heading southwest, with views of the project site likely lasting from 10 to 20 seconds. For this viewer group duration of view is estimated to be moderately low.

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[62] The following references made to distances/cardinal directions between the OEHI component and KOP 6, are in regards to the CO_2 EOR Processing Facility, as this would be the most prominent/visible element of the OEHI site.

[63] See **Visual Resources Figures 16a** and **16b**.

[64] The closest AADT volume count to the U.S. Post Office is Tupman Road, north of Taft Highway.

Visibility of the project site from KOP 6 is moderately low, and the number of viewers is moderately low. Duration of view for motorists is moderately low. Based on the ratings for visibility, number of viewers, and duration of view, overall viewer exposure for KOP 6 is considered moderately low to moderate.

Visual quality is characterized as low to moderately low. Viewer concern is moderate to moderately high. Based on the ratings for visual quality, viewer concern, and overall viewer exposure, overall visual sensitivity is considered moderately low to moderate.

Visual Change

For KOP 6, the most prominent visual change introduced into the VSOI would be construction equipment involved in injection and production well installations in the distant hills. However, equipment used for these activities are already part of current daily operations and would not substantially alter the existing VSOI. It is likely that the construction equipment that might be visible from KOP 6 would offer little contrast, dominance or view blockage to the existing VSOI. Therefore, for KOP 6, the *overall visual change* would be moderately low.

Visual Impact Determination

Overall visual sensitivity for KOP 6 is considered moderately low and *overall visual change* is considered moderately low. Energy Commission staff concludes that introducing the publicly visible project structures into the existing view at KOP 6 would not cause substantial degradation of the existing visual character of the site and its surroundings. Therefore, a less-than-significant impact to visual resources is identified for KOP 6. No mitigation is required.

VISUAL CHARACTER AND QUALITY – CONCLUSION (OEHI)

Energy Commission staff evaluated the proposed OEHI component's effects on visual resources at the six selected OEHI KOPs. The visual impact determinations are focused on the overall visual sensitivity for each KOP and whether the OEHI component would cause substantial degradation of the existing visual character of the site and its surroundings.

Staff determined that the impacts at KOP 1, KOP 2, KOP 3, KOP 4, KOP 5, and KOP 6 did not meet or exceed the criterion set forth in the discussion above. Therefore, the project would not cause substantial degradation of the existing visual character of the site and its surroundings at these six KOPs.

New Source of Substantial Light or Glare

Implementation of both the proposed HECA and its OEHI component would introduce new sources of light and glare into the VSOI. Lighting of new structures and buildings would be required, and construction of the projects would introduce new reflective surfaces in the project area. Exterior lighting would serve the function of promoting worker and aviation safety[65] and security at the HECA plant site and the OEHI CO_2 Processing Facility. Light and glare from the HECA plant site and facility could adversely affect the daytime and nighttime views of nearby residents and other viewer groups with foreground and middleground views of the project site. Energy Commission staff considers this to be a significant impact to visual resources.

However, the combination of broad geographic distribution, topographic variations of the existing landscape, and the fact that the nighttime character of the areas where this new lighting would occur is already developed with significant lighting, would likely result in minimal noticeable impacts for sensitive viewers. Further, **VIS-4** is proposed requiring preparation and implementation of a lighting management plan to minimize potential effects relating to light trespass beyond the project site. **VIS-6** is proposed requiring all lights used to illuminate the interior parking area to be directed away from any adjacent properties and streets. Therefore, Energy Commission staff concludes that, with the above conditions of certifications, combined with applicant's proposed mitigation measures,[66] impacts relating to light would be reduced to less-than-significant levels. No substantial sources of day or nighttime glare are expected to be created by the elements of the proposed project. However, because of the potential for the proposed HECA transmission line pole structures to cause glint and glare effects, **VIS-1** includes a recommendation that a non-reflective (e.g., matte or dull gray), bare galvanized finish be used for the tapered steel poles supporting the transmission lines. Further, conductors and insulators are required to be non-specular and non-reflective. **VIS-3** is proposed requiring all publicly visible signage to be colored, treated, and finished to prevent excessive glare. These measures ensure that distracting or hazardous reflections from the structures would not occur and to minimize the contrast of the structures with their backdrops. Therefore, Energy Commission staff concludes that impacts relating to glare would be reduced to less-than-significant levels. Construction activities would cover portions of both project construction sites depending on the construction activity, and any necessary work at night would require lighting to cover limited portions of the whole project site. Energy Commission staff considers lighting of construction areas to be a potentially significant impact to visual resources. Project construction for the HECA project is expected to begin in the third quarter of 2013 and continue for 42 months. Commissioning and Start-Up is expected to continue for an additional 7 months (total 49 months). The schedule has been estimated on a single-shift, 5-day basis, beginning at 6 a.m., Monday through Friday. Additional hours and/or a second shift may be necessary to make up weather delays, schedule deficiencies or to complete critical construction activities. During start-up and testing, some activities may continue up to 24 hours per day, 7 days per week (Hydrogen Energy International 2012). Condition of Certification **VIS-5** requires operation of lighting during project construction to minimize potential effects relating to light trespass beyond the construction areas. Therefore, with implementation of **VIS-5**, Energy Commission staff concludes that impacts relating to light and glare during construction activities would be reduced to less-than-significant levels.

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[65] See FAA Advisory Circular 70/7460-1 K Change 2, Obstruction Marking and Lighting, paint/red lights - Chapters 3 (Marked), 4, 5 (Red), & 12 (See "HECA Applications for Notice of Proposed Construction or Alteration (Off Airport) (TN# 66029)").
[66] See **Mitigation Measure AES-1** and **-3**.

The proposed HECA project is being designed to avoid flaring during steady state operations and to minimize flaring during startup and shut-down operations (Hydrogen Energy International 2012). The occasional operation of flares at night could be visible to viewer groups with foreground and middleground views of the project site. Flaring at the project site would be infrequent and is not expected to increase the magnitude of the overall impact relating to lighting effects. In relation to the OEHI component, the CO_2 EOR Processing Facility would be equipped with two emergency flares that have the potential to emit light during nighttime operations. There are existing emergency flares currently being operated within the EHOF. The addition of two emergency flares at the facility is not expected to substantially alter the amount of light being emitted from the EHOF. Therefore, Energy Commission staff considers flaring to be a less-than-significant impact of the project. No mitigation is required.

CUMULATIVE IMPACTS AND MITIGATION

Section 15130 of the State CEQA Guidelines requires a discussion of cumulative impacts of a project when the project's incremental effect is cumulatively considerable. According to State CEQA Guidelines Section 15065, "[c]umulatively considerable means that the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects." Sections 15130 and 15355 of the State CEQA Guidelines both stress cumulative impacts in the context of *closely related* projects and from projects *causing related impacts*. The goal of such an analysis is twofold: first, to determine whether the overall long-term impacts of all such projects would be cumulatively significant; and second, to determine whether the HECA power plant project itself would cause a "cumulatively considerable" (and thus significant) incremental contribution to any such cumulatively significant impacts.

Based on Section 15130(b) of the State CEQA Guidelines, this analysis of cumulative impacts relies on the use of a list of projects producing related or cumulative impacts. Because of the rural nature of the project area and the lack of developed uses, the contributions of past and present projects to visual resources conditions are adequately captured in the description of the existing setting and need not be listed here. This analysis of cumulative effects on visual resources addresses the potential incremental impacts of the proposed HECA and its OEHI component in combination with similar effects of other probable future projects. For visual resources, the geographic scope of the area that could be affected by the cumulative effect is considered to be the project VSOI where light and glare generated by multiple projects might interact on a cumulative basis.

Energy Commission staff has prepared a list of probable future projects within the VSOI (a six-mile radius of the HECA project site and its OEHI component).[67] Within the VSOI, changes to visual resources from the other projects could combine with visual resources impacts of the HECA project to cause a cumulatively considerable effect. Staff finds no probable future projects within the VSOI that could cause significant adverse impacts to visual resources. Therefore, although a significant visual impact has been identified at

[67] See **Visual Resources Figure 18**.

KOP 1 (HECA), there are no other probable future projects within the VSOI that, in conjunction with the significant impact at KOP 1, would cause a cumulatively considerable impact to visual resources.

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Visual Resources Table 7 addresses consistency of the proposed HECA project with LORS relating to protection of visual resources. The proposed HECA project is being planned and would be implemented to comply with the Kern County General Plan and Title 19, Zoning, of the Kern County Zoning Ordinance.

In July of 2012, the Kern County Planning Department amended its zoning ordinance to include a Dark Skies Ordinance and revisions to Chapter 19.86, Landscaping. The HECA project's consistency with the proposed Dark Skies Ordinance and applicable portions of Chapter 19.86, are addressed in **Table 7**. Preparation and submittal of a lighting management plan as described below under Condition of Certification **VIS-4** would ensure compliance with Kern County requirements for lighting of the project site. In **Table 7**, applicable chapters and sections of the Kern County Zoning Ordinance are briefly described under the column, "Policy and Strategy Description."

The Energy Commission has the exclusive authority to license power plants in the state with a generating capacity of 50 megawatts or greater. Therefore, all required local approvals and entitlements for the HECA project would be covered under the Energy Commission's in lieu permitting authority.

Visual Resources Table 7
Project Compliance with Applicable Visual Resources LORS

Source	Policy and Strategy Description	Consistency Determination	Basis for Consistency
Kern County General Plan – Land Use, Open Space, and Conservation Element			
1.8 Industrial (Kern County Planning Department 2009)	Policy 6. Encourage upgrading the visual character of existing industrial areas through the use of landscape elements, screens, or buffers.	Yes, as conditioned	Consistent, with implementation of Conditions of Certification **VIS-1**, **VIS-2**, **VIS-3**, and **VIS-6.**
	Policy 7. Require that industrial uses provide design features such as screen walls, landscape elements, increased height and/or setbacks, and lighting restrictions	No	Conditions of Certification **VIS-1**, **VIS-2**, **VIS-3**, **VIS-4** and **VIS-6** will mitigate some of the project's effects on the visual character and quality in the area where the project would be sited. However, the visual impact of the project at KOP 1 is, at present, significant and unavoidable.

Visual Resources Table 7
Project Compliance with Applicable Visual Resources LORS

Source	Policy and Strategy Description	Consistency Determination	Basis for Consistency
	between the boundaries of adjacent residential land use designations so as to reduce impacts to residential uses relating to light, noise, sound, and vibration.		
1.10.7 General Provisions, Light and Glare (Kern County Planning Department 2009)	Light and Glare Policy 47 and 48. Ensure that light and glare from discretionary new development projects are minimized in rural as well as urban areas. Encourage the use of low-glare lighting to minimize nighttime glare effects on neighboring properties.	Yes, as conditioned	Consistent, with implementation of Conditions of Certification **VIS-1**, **VIS-3**, **VIS-4**, **VIS-5**, and **VIS-6**.
Kern County Zoning Ordinance – Chapter 19.12 Exclusive Agriculture (A) District			
19.12.110 Signs	Describes the types of signs that are permitted in the A District, in accordance with the requirements of Chapter 19.84, Signs.	Yes, as conditioned	Consistent, with implementation of Condition of Certification **VIS-3**.

Visual Resources Table 7
Project Compliance with Applicable Visual Resources LORS

Source	Policy and Strategy Description	Consistency Determination	Basis for Consistency
Kern County Zoning Ordinance – Chapter 19.81 Dark Skies Ordinance			
19.81.040 General Requirements	Describes general standards for all outdoor lighting fixtures subject to the dark skies ordinance.	Yes, as conditioned	Consistent, with implementation of Condition of Certification **VIS-4**.
Kern County Zoning Ordinance – Chapter 19.82 Off-Street Parking			
19.82.090 Parking Area Design and Development Standards	Addresses standards for landscaping of parking lots, glare, and lighting.	Yes, as conditioned	Consistent, with implementation of Conditions of Certification **VIS-6**.
Kern County Zoning Ordinance – Chapter 19.84 Signs			
19.84.020, 19.84.030, and 19.84.040 Design and Development Standards – Monument Signs, Pole Signs, and Signs Attached to Buildings	These three sections of Chapter 19.84 address standards for freestanding monument and pole signs and signs attached to a building or wall.	Yes, as conditioned	Consistent, with implementation of Condition of Certification **VIS-3**.
Kern County Zoning Ordinance – Chapter 19.86 Landscaping			
19.86.020 Landscaping Standards – Generally	Describes minimum plant and tree sizes for landscaping.	Yes, as conditioned	Consistent with implementation of Condition of Certification **VIS-2**.

Visual Resources Table 7
Project Compliance with Applicable Visual Resources LORS

Source	Policy and Strategy Description	Consistency Determination	Basis for Consistency
19.86.060 Landscaping Standards – Industrial Uses	Describes minimum standards for landscaping for industrial uses.	Yes, as conditioned	Consistent with implementation of Condition of Certification **VIS-2**. The project site has no property lines abutting any residentially zoned lots.
19.86.070 Landscape and Irrigation Plan – Required	Identifies classes of projects that are subject to preparation of landscape and irrigation plans.	Yes, as conditioned	Consistent with implementation of Condition of Certification **VIS-2**.
19.86.080 Landscape and Irrigation Plan – Review and Approval	Addresses submittal of conceptual landscape and irrigation plans for projects requiring a discretionary or ministerial approval.	Yes, as conditioned	Consistent with implementation of Condition of Certification **VIS-2**.
19.86.090 Landscape Installation – Timing	Requires installation of the landscape and irrigation systems or posting of an acceptable financial assurance prior to issuance of an occupancy permit.	Yes, as conditioned	Consistent with implementation of Condition of Certification **VIS-2**.

Note: The complete text of Kern County's general plan and zoning ordinance, are available at http://www.co.kern.ca.us/planning/pdfs/kcgp/KCGP.pdf and http://www.co.kern.ca.us/planning/pdfs/KCZOJul12.pdf, respectively.

NOTEWORTHY PUBLIC BENEFITS

Neither the applicant nor staff has identified any visual benefits associated with the proposed HECA project. The proposed project would introduce several landscaping, surface treatment, lighting, and signage mitigation measures (Conditions of Certification **VIS-1** to **VIS-6**). However, all are necessary to mitigate potential visual impacts caused by the project, and, therefore, are not considered to be public benefits.

DEPARTMENT OF ENERGY'S FINDINGS REGARDING DIRECT AND INDIRECT IMPACTS OF THE NO-ACTION ALTERNATIVE

Under the No-Action Alternative, the Department of Energy (DOE) would not provide financial assistance to the applicant for the HECA project. The applicant could still elect to construct and operate its project in the absence of financial assistance from DOE, but DOE believes this is unlikely. For the purposes of analysis in the PSA/DEIS, DOE assumes the project would not be constructed under the No-Action Alternative. Accordingly, the No-Action Alternative would have no impacts associated with this resource area.

RESPONSE TO PUBLIC AND AGENCY COMMENTS

As of this PSA/DEIS, no agency or public comments have been received regarding visual resources.

STAFF'S CONCLUSIONS

Impacts to visual resources for the proposed HECA project and its OEHI component were assessed based on the magnitude of the anticipated changes to the visual environment and the estimated effects of those changes on viewer groups with foreground and middleground views of the project site. The visual resources analysis was conducted in accordance with CEQA (Pub. Resources Code § 21000 et seq.) and the State CEQA Guidelines (14 Cal. Code Regs. § 15000 et seq.).

Energy Commission staff concludes that the HECA project would not comply with all applicable visual resource standards under CEQA or LORS, as a significant impact to visual resources is identified at KOP 1 (HECA). Conditions of Certification **VIS-1**, **VIS-2**, **VIS-3**, **VIS-4**, and **VIS-6** address surface treatments for structures and buildings at the power plant site, landscaping, requirements for project signage, lighting management plan, and landscape and irrigation requirements for the interior parking area, respectively. Implementation of these above conditions would not reduce the impact at KOP 1 to a less-than-significant level. Staff concludes that additional project information is necessary to adequately assess whether implementation of all feasible mitigation would reduce the impact at KOP 1 to a less-than-significant level.

The visual impact discussion for KOP 1 (HECA) describes applicant's intention to prepare and submit an off-site conceptual landscape plan to mitigate the significant impact at KOP 1. If the off-site conceptual landscape plan was reviewed and, subsequently approved, a new condition of certification would be added to the FSA/FEIS for the project requiring implementation of the off-site landscape plan. Further, the visual resources analysis in the FSA/FEIS would include an assessment of the effectiveness of the proposed conditions of certification, including the off-site landscape plan, and whether the impact would be reduced to a less-than-significant level.

Energy Commission staff concludes that introducing the publicly visible structures into the existing views at KOP 2, KOP 3, KOP 4, KOP 6 (and all six of the KOPs for the project's OEHI component) would not cause substantial degradation of the visual character of the site and its surroundings. Therefore, the impacts to visual resources from these KOPs are less-than-significant.

Staff evaluated the potential effects of publicly visible water vapor plumes on visual resources. Based on results of the visible plume modeling analysis prepared by staff for the HECA project, plumes from the HRSG stack are predicted to occur less than 20 percent of the time during "seasonal daylight clear" hours. Additionally, plumes from the ASU cooling tower, the 13-cell power block cooling tower, and coal dryer stack are predicted to occur more than 20 percent of the time during seasonal daylight clear hours. However, further analysis resulted in the conclusion by staff that the plumes from the ASU cooling tower, the 13-cell power block cooling tower, and coal dryer stack would be visually subordinate compared to the other built structures that would be installed at the project site, and that introduction of visible vapor plumes in the environment is considered a less-than-significant impact of the project.

Light and glare effects from the plant site (during its construction and operational phases) could adversely affect the daytime and nighttime views for nearby residents and other viewer groups. With implementation of Conditions of Certification **VIS-1**, **VIS-3**, **VIS-4**, **VIS-5**, and **VIS-6**, potential nighttime light and daytime glare effects would be reduced to a less-than-significant level.

The following proposed conditions of certification for the HECA project is intended to mitigate impacts of the project on visual resources, in accordance with the State CEQA Guidelines. Mitigation is defined as:

(a) Avoiding the impact altogether by not taking a certain action or parts of an action.

(b) Minimizing impacts by limiting the degree or magnitude of the action and its implementation.

(c) Rectifying the impact by repairing, rehabilitating, or restoring the impacted environment.

(d) Reducing or eliminating the impact over time by preservation and maintenance operations during the life of the action.

(e) Compensating for the impact by replacing or providing substitute resources or environments (14 Cal. Code Regs. § 15370).

To meet these standards for mitigation of impacts, Energy Commission staff recommends implementing Conditions of Certification **VIS-1** through **VIS-6**.

PROPOSED CONDITIONS OF CERTIFICATION

VIS-1 **Surface Treatment of Project Structures and Buildings**

The project owner shall prepare and implement a surface treatment plan for the project. The project owner shall color, treat, and finish the surfaces of all project structures, buildings, and fences visible to the public to ensure that visual intrusion and contrast with the landscape is minimized to the extent feasible, and glare from treated surfaces is minimized.

The surface treatment plan shall include, at a minimum, the following plan elements:

a.) Description of the overall rationale for the proposed surface treatments, including selection of the proposed colors and finishes;

b.) Proposed opportunities and options for enhancing design quality and visual interest of project structures, consistent with project objectives;

c.) Inventory of major project structures and buildings (e.g., buildings, tanks, and pipes; transmission line towers and/or poles; and fencing) specifying the proposed colors and finishes. Colors must be identified by vendor, name, and number, or according to a universal designation system;

d.) One set of color brochures or color chips showing each proposed color and finish;

e.) One set of 11-inch by 17-inch color photographic simulations at life size scale of the treatment proposed for use on project structures at the main plant site, including structures treated during manufacture, from KOP 1;

f.) Schedule for completing the surface treatments; and

g.) Procedure to ensure proper treatment maintenance for the life of the project.

The transmission line conductors and insulators shall be non-specular and non-reflective. The tapered steel poles supporting the transmission lines shall be the type that are galvanized using the hot dip zinc or equivalent process to produce a matte gray surface finish. No galvanizing process shall be used that produces a reflective metallic finish.

Verification: At least 90 calendar days prior to submitting specifications for colors, finishes, and other surface treatments to manufacturers or vendors of project structures, and/or ordering prefabricated project structures, the project owner shall submit the surface treatment plan to the Compliance Project Manager (CPM) for review and comment. If the CPM determines that the plan requires revision, the project owner shall provide a plan with the specified revision(s) for review and approval by the CPM. No work to implement the project's surface treatment plan shall begin until final plan approval is received from the CPM.

Prior to the start of commercial operation of the project, the project owner shall notify the CPM that surface treatments of all publicly visible structures and buildings identified in the surface treatment plan have been completed and that the facilities are ready for inspection. Prior to the scheduled inspection, the project owner shall prepare and submit one set of electronic color photographs of the project site from the viewpoint for KOP 1. The project owner shall obtain written confirmation from the CPM that the project complies with the surface treatment plan. The project owner shall provide a status report regarding surface treatment maintenance in the Annual Compliance Report. At a minimum, the report shall specify:

- condition of the surfaces of all structures at the main plant site for the reporting year,
- major maintenance activities that occurred during the reporting year, and
- a schedule for major maintenance activities for the next year.

VIS-2 **Landscaping**

The project owner shall prepare and implement a landscape plan consistent with the zoning ordinances of Kern County, specifically section 19.86 et al. The project owner and/or the construction manager for landscaping shall review section19.86 et al to ensure compliance with all applicable sections of the ordinance. At a minimum, the landscape plan shall satisfy these criteria:

a.) Minimum plant and tree sizes for landscaping are as follows: trees (15 gallons), shrubs (5 gallons), and small shrubs and groundcovers (1 gallon).

b.) A minimum of five percent of the developed area shall be landscaped. A maximum of one-half of the five percent may be turf or an alternative ground cover.

c.) Within each planter or landscaped area, an irrigation system and landscaping shall be provided and maintained.

d.) Landscaping materials and trees installed in planters or landscaped areas shall be selected based upon their adaptability to the climatic, geologic, and topographical conditions of the site.

e.) Landscaping and irrigation for the project shall comply with the County's Water Efficient Landscape requirements.

f.) Maintenance procedures shall be specified, including any needed irrigation and a plan for routine annual or semi-annual debris removal for the life of the project.

g.) A procedure for monitoring and replacing unsuccessful plantings for the life of the project shall be described.

h.) After construction, areas where vegetation has been removed will be restored consistent with the surrounding area.

<u>**Verification**</u>: Prior to commercial operation and at least 45 days prior to installing the landscaping plan, the project owner shall submit the landscaping plan to the CPM for approval and simultaneously to the Kern County Planning Director (Director) for comment. The project owner shall provide a copy of the Planning Director's comments to the CPM prior to the installation of the landscaping.

The project owner shall allow the Director 30 days to provide comment on the submitted surface treatment plan. The project owner shall provide a copy of the Director's comments to the CPM.

If the CPM determines that the plan requires revision, the project owner shall provide to the CPM and the Director a plan with the specified revision(s) for review and approval by the CPM before the plan is implemented.

Landscape elements and irrigation shall be installed prior to the start of commercial operation of the project. The project owner shall simultaneously notify the CPM and the Director that the landscaping is ready for inspection within seven days after completing installation of the landscaping.

The project owner shall report landscape maintenance activities, including replacement of dead vegetation, for the previous year of operation in the Annual Compliance Report for the project.

VIS-3 **Publicly Visible Project Signage**

The project owner shall prepare and implement a signage plan for the project. Any publicly visible project-related signage shall be colored, treated, and finished to minimize visual contrast and intrusion and prevent excessive glare. The project owner shall ensure that the signage plan complies with Chapter 19.84, Signs, of the Kern County Zoning Ordinance. The design of any signs required by safety regulations shall conform to the criteria established by the zoning ordinance. The project owner and/or the construction manager shall review Chapter 19.84 to ensure compliance with all applicable sections of the ordinance.

The signage plan shall be submitted to the Director and the CPM for simultaneous review and comment. If the Director submits comments in the signage plan, a copy of those comments shall be provided to the CPM. The project owner shall not implement the signage plan until written approval of the final plan is received from the CPM.

Verification: At least 30 calendar days before ordering signage for the project, the project owner shall submit the signage plan to the CPM and the Director for simultaneous review and comment. The project owner shall provide to the CPM a copy of the transmittal letter submitted to the Kern County Planning Department requesting the Director's review of the signage plan.

If the CPM determines that the plan requires revision, the project owner shall provide a plan with the specified revision(s) for review and approval by the CPM and provide a copy of the revised plan to the Director. No work to implement the signage plan shall begin until final plan approval is received from the CPM.

Installation of signs must be completed by the start of commercial operation of the project. Within 14 calendar days of installing project signage, the project owner shall simultaneously notify the CPM and the Director that publicly visible signs have been installed and provide the CPM and the Director with electronic color photographs of the installed signage. The project owner shall obtain written confirmation from the CPM that the sign installations comply with the signage plan for the project.

The project owner shall include information on any required repairs or replacement of project signage in the Annual Compliance Report for the project.

VIS-4 Permanent Exterior Lighting

The project owner shall prepare and implement a lighting management plan for the project. Consistent with safety and security considerations, commercial availability of lighting products, and project objectives, the project owner shall design, install, and maintain all permanent exterior lighting such that:

a.) light fixtures do not cause obtrusive spill light (i.e., light trespass) beyond the project site;

b.) lighting does not cause excessive reflected glare;

c.) direct lighting of the project does not illuminate the nighttime sky;

d.) illumination of the project and its immediate vicinity is minimized;

e.) lights in high illumination areas not occupied on a continuous basis (such as maintenance platforms) include switches, timer switches, or motion detectors so that the lights are operated only when the area is occupied;

f.) lighting fixtures are kept in good working order and continuously maintained according to the original design intent of the lighting system;

g.) lighting is consistent with Kern County's Dark Sky Ordinance.

h.) lights used to illuminate parking area shall be directed away from any adjacent properties and streets;

i.) High-pressure sodium vapor fixtures will be used which will reduce visual contrast with the night sky; and

j.) Stacks and other tall project elements will be lit in accordance with FAA guidelines.

Topics to address in the lighting management plan shall include, at a minimum, fixture and control schedules, fixture and control cut sheets and specifications, a photometric plan showing vertical and horizontal footcandles at all property lines to a height of 20 feet, and the proposed time clock schedule for lighting.

The lighting management plan shall also describe the process to prepare and submit nuisance complaints relating to lighting at the project sites. The report of complaint shall include a proposal to resolve the complaint and an implementation schedule. The project owner shall notify the CPM when any necessary actions to resolve the complaint have been completed.

The lighting management plan shall be submitted to the Director and the CPM for simultaneous review and comment. If the Director submits comments on the lighting management plan, a copy of those comments shall be provided to the CPM. The project owner shall not purchase or order any permanent exterior lighting until written approval of the final plan is received from the CPM.

Verification: At least 90 calendar days before ordering any permanent exterior lighting, the project owner shall contact the CPM to discuss the lighting management plan, including the standards and specifications described above. At least 60 calendar days prior to ordering any permanent exterior lighting, the project owner shall submit a lighting management plan to the CPM and the Director for simultaneous review and comment. The project owner shall provide to the CPM a copy of the transmittal letter submitted to the Kern County Planning Department requesting the Director's review of the lighting management plan.

If the CPM determines that the plan requires revision, the project owner shall provide a plan with the specified revision(s) for review and approval by the CPM and provide a copy of the revised plan to the Director. No work to implement the plan (e.g., purchasing of fixtures) shall begin until final plan approval is received from the CPM.

Prior to the start of commercial operation of the project, the project owner shall simultaneously notify the CPM and the Director that installation of permanent exterior lighting for the project has been completed and that the system is ready for inspection. If the CPM notifies the project owner that modifications to the lighting system are required, within 30 days of receiving that notification, the project owner shall implement all specified changes and notify the CPM that the modified lighting system is ready for inspection.

Within 48 hours of receiving a project-related lighting complaint, the project owner shall complete a lighting complaint resolution form for submittal to the CPM. The form shall include a proposal to resolve the complaint. The project owner shall notify the CPM within 48 hours of completing implementation of the proposal. A copy of the complaint resolution form report shall be submitted to the CPM within 30 calendar days of complaint resolution. The project owner shall report any lighting complaints and documentation of resolution for the previous year of operation in the Annual Compliance Report for the project. All records of lighting complaints shall be kept in the on-site compliance file for the project.

VIS-5 Construction Activity Lighting

Consistent with safety and security considerations and project objectives, the project owner shall ensure that lighting of construction areas minimizes potential night lighting impacts by implementing the following measures:

a.) All fixed position lighting shall be hooded and shielded to direct light downward and toward the area to be illuminated to prevent illumination of the night sky and minimize light trespass.

b.) Wherever and whenever feasible, lighting shall be kept off when not in use.

Any complaints about construction lighting shall be conveyed to the project owner and the CPM. The project owner shall complete a lighting complaint resolution form for submittal to the CPM. The complaint resolution form shall be used to record each lighting complaint and document resolution of the complaint. The project owner shall provide a copy of each completed complaint form to the CPM.

Verification: Within 7 calendar days after the first use of construction lighting, the project owner shall notify the CPM that the lighting is ready for inspection. If the CPM determines that modifications to the lighting are needed, within 14 days of receiving that notification, the project owner shall correct the lighting and notify the CPM that modifications have been completed.

Within 48 hours of receiving a lighting complaint, the project owner shall provide to the CPM:

- a report of the complaint,
- a proposal to resolve the complaint, and
- a schedule for implementing the proposal.

The project owner shall notify the CPM within 48 hours of implementing the proposal. The project owner shall provide a copy of the completed complaint resolution form to the CPM in the Monthly Compliance Report for the following month.

VIS-6 Landscaped Interior Parking Area

The project owner shall prepare and implement a landscape plan for the interior parking area consistent with the zoning ordinances of Kern County, specifically section 19.82.090. The project owner and/or the construction manager for landscaping shall review section 19.82.090 to ensure compliance with all applicable sections of the ordinance. At a minimum, the landscape plan shall satisfy these criteria:

a.) For all parking lots containing ten (10) or more spaces, at least five percent of the total interior area devoted to parking shall be landscaped.

b.) Trees shall be planted and maintained throughout the parking area at a minimum ratio of one tree per six parking spaces placed at a maximum of 65-foot intervals. The minimum tree size shall be a 15-gallon container.

c.) Unless otherwise permitted under a discretionary permit, minimum plant and tree sizes for landscaping are as follows: trees (15 gallon), shrubs (5 gallon), and small shrubs and groundcovers (1 gallon).

Within each planter or landscaped area, an irrigation system and live landscaping shall be provided and maintained.

d.) If the parking facility includes diagonal or perpendicular parking spaces that abut a public street or road, an ornamental fence, wall, evergreen landscaping or berm, or any combination of the above, of not more than 4 feet in total height shall be erected between the parking facility and the street or road to eliminate headlight glare.

e.) Lights used to illuminate parking area shall be directed away from any adjacent properties and streets.

f.) Species of trees shall be selected to ensure that tree canopies of mature trees shade a minimum of 40 percent of the total parking lot area. Selected tree species shall be native to the region, non-invasive, and drought tolerant.

Verification: The landscape and irrigation plan for the interior parking area shall be submitted by the HECA project owner to the Director and the CPM for simultaneous review and comment. If the Director submits comments on the landscape plan for the parking area, the project owner shall provide a copy of those comments to the CPM. The project owner shall not implement the plan until written approval of the final plan is received from the CPM. Modifications to the landscape plan for the interior parking area are prohibited without approval from the CPM. At least 90 calendar days before beginning installation of irrigation and landscape elements for the parking area, the project owner shall submit the plan to the CPM and the Director for simultaneous review and comment. The project owner shall provide to the CPM a copy of the transmittal letter submitted to the Kern County Planning Department requesting the Director's review of the parking area landscape plan.

If the CPM determines that the plan requires revision, the project owner shall provide a plan with the specified revision(s) for review and approval by the CPM. A copy of the revised plan shall be provided to the Director.

Landscape elements and irrigation shall be installed prior to the start of commercial operation of the project. Within 14 calendar days of completing the landscape work for the interior parking area, the project owner shall simultaneously notify the CPM and the Director that installation of landscape elements and irrigation has been completed and that the system is ready for inspection. Required modifications to the plantings and installed irrigation system shall be implemented within 30 calendar days of the inspection. The project owner shall obtain written confirmation from the CPM that the project complies with the landscape plan for the parking area.

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APPENDIX VR-1

ENERGY COMMISSION VISUAL RESOURCE ANALYSIS EVALUATION CRITERIA

Energy Commission staff conducts a visual resource analysis according to Appendix G, “Environmental Checklist Form—Aesthetics,” California Environmental Quality Act (CEQA). The CEQA analysis requires that commission staff make a determination of impact ranging from “Adverse and Significant” to “Not Significant.”

Staff’s analysis is based on Key Observation Points or KOPs. KOPs are photographs of locations within the project area that are highly visible to the public—for example, travel routes; recreational and residential areas; and bodies of water as well as other scenic and historic resources.

Those photographs are taken to indicate existing conditions without the project and then modified to include a simulation of the project. Consequently, staff has a visual representation of the viewshed before and after a project is introduced and makes its analysis accordingly. Information about that analytical process follows.

Visual Resource Analysis Without Project

When analyzing KOPs of existing conditions without the project, staff considers the following conditions: visual quality, viewer concern, visibility, number of viewers, duration of view. Those conditions are then factored into an overall rating of viewer exposure and viewer sensitivity. Information about each condition and rating follows.

VISUAL QUALITY

An expression of the visual impression or appeal of a given landscape and the associated public value attributed to the resource. Visual quality is rated from *high* to *low*. A high rating is generally reserved for landscapes viewers might describe as picture-perfect.

Landscapes rated high generally are memorable because of the way the components combine in a visual pattern. In addition, those landscapes are free from encroaching elements, thus retaining their visual integrity. Finally, landscapes with high visual quality are visually coherent and harmonious when each element is considered as part of the whole. On the contrary, landscapes rated *low* are often dominated by visually discordant human alterations.

VIEWER CONCERN

Viewer concern represents the reaction of a viewer to visible changes in the viewshed, the area of land visible from a fixed vantage point. For example, viewers have a high expectation for views formally designated as a scenic area or travel corridor as well as for recreational and residential areas. Viewers generally expect that those views would be preserved. Travelers on highways and roads, including those in agricultural areas, are generally considered to have moderate viewer concerns and expectations. However, viewers tend to have low-to-moderate viewer concern when viewing commercial buildings. And industrial uses typically have the lowest viewer concern. Regardless, the level of concern could be lower if the existing landscape contains discordant elements. In addition, some areas of lower visual quality and degraded visual character may contain particular views of substantially higher visual quality or interest to the public.

VISIBILITY

Visibility is a measure of how well an object can be seen. Visibility depends on the angle or direction of views; extent of visual screening; and topographical relationships between the object and existing homes, streets, or parks. In that sense, visibility is determined by considering any and all obstructions that may be in the sightline—trees and other vegetation; buildings; transmission poles or towers; general air quality conditions such as haze; and general weather conditions such as fog.

NUMBER OF VIEWERS

Number of viewers is a measure of the number of viewers per day who would have a view of the proposed project. *Number of viewers* is organized into the following categories: residential according to the number of residences; motorist according to the number of vehicles; and recreationists.

DURATION OF VIEW

Duration of view is the amount of time to view the site. For example, a high or extended view of a project site is one reached across a distance in two minutes or longer. In contrast, a low or brief duration of view is reached in a short amount of time—generally less than ten seconds.

VIEWER EXPOSURE

Viewer exposure is a function of three elements previously listed, *visibility*, *number of viewers*, and *duration of view*. Viewer exposure can range from a *low* to *high*. A partially obscured and brief background view for a few motorists represents a low value; and unobstructed foreground view from a large number of residences represents a high value.

VISUAL SENSITIVITY

Visual sensitivity is comprised of three elements previous listed, *visual quality*, *viewer concern*, and *viewer exposure*. Viewer sensitivity tends to be higher for homeowners or people driving for pleasure or engaged in recreational activities and lower for people driving to and from work or as part of their work.

Visual Resource Analysis with Project

Visual resource analyses with photographic simulations of the project involve the elements of contrast, dominance, view disruption, and visual change. Information about each element follows.

CONTRAST

Contrast concerns the degree to which a project's visual characteristics or elements — form, line, color, and texture — differ from the same visual elements in the existing landscape. The degree of contrast can range from *low* to *high*. A landscape with forms, lines, colors, and textures similar to those of a proposed energy facility is more visually absorbent; that is, more capable of accepting those characteristics than a landscape in which those elements are absent. Generally, visual absorption is inversely proportional to visual contrast.

DOMINANCE

Dominance is a measure of (a) the proportion of the total field of view occupied by the field; (b) a feature's apparent size relative to other visible landscape features; and (c) the conspicuousness of the feature due to its location in the view.

A feature's level of dominance is lower in a panoramic setting than in an enclosed setting with a focus on the feature itself. A feature's level of dominance is higher if it is (1) near the center of the view; (2) elevated relative to the viewer; or (3) has the sky as a backdrop. As the distance between a viewer and a feature increases, its apparent size decreases; and consequently, its dominance decreases. The level of dominance ranges from *low* to *high*.

VIEW DISRUPTION

The extent to which any previously visible landscape features are blocked from view constitutes view disruption. The view is also disrupted when the continuity of the view is interrupted. When considering a project's features, higher quality landscape features can be disrupted by lower quality project features, thus resulting in adverse visual impacts. The degree of view disruption can range from *none* too *high*.

VISUAL CHANGE

Visual change is a function of *contrast*, *dominance*, and *view disruption*. Generally, *contrast* and *dominance* contribute more to the degree of visual change than does *view disruption*.

APPENDIX VR-2: VISIBLE PLUME MODELING ANALYSIS[68]

INTRODUCTION

The following provides the assessment of the Hydrogen Energy California Project (HECA) gas turbine heat recovery steam generator (HRSG), coal dryer, and cooling tower exhaust stacks visible plumes. Staff completed a modeling analysis for the applicant's proposed unabated gas turbine/HRSG, coal dryer and cooling towers.

PROJECT DESCRIPTION

The applicant has proposed one MHI 501GAC combustion turbine-generator (CTG)/HRSG with duct burners. The applicant has not proposed to use any methods to abate visible plumes from the HRSG exhaust, and none seem to be warranted given the visual impact analysis conducted by staff.

For project cooling the applicant has proposed a four-cell air separation unit cooling tower, a 12-cell power block cooling tower and a 13-cell process cooling tower. All cooling towers are linear (one by four, etc.) design. The 12-cell cooling tower and the 13-cell cooling tower are aligned as if they comprise one 25-cell tower in a west-east direction. The applicant has not proposed to use any methods to abate visible plumes from the three cooling towers.

The facility would also consist of a manufacturing complex, proposed to create low-carbon nitrogen-based agricultural products. Sources in the manufacturing complex that have visible plume potential include the urea unit absorber vent and the urea ammonia nitrate complex vent scrubber. However, the visible impact would be insignificant for these sources in comparison to the project's larger HRSG and cooling tower impacts.

Finally, Occidental of Elk Hills, inc. (OEHI) would receive the carbon dioxide (CO_2) from HECA and use it for enhanced oil recovery operations. This would include a CO_2 recovery unit to separate CO_2 from recovered crude oil. Sources associated with the CO_2 recovery unit that have visible plume potential include the refrigeration system and discharge cooler. But again, the visible impact would be insignificant for these sources in comparison to the project's larger HRSG and cooling tower impacts.

VISIBLE PLUME MODELING METHODS

PLUME FREQUENCY AND DIMENSION MODELING

The Combustion Stack Visible Plume (CSVP) model was used to estimate plume frequency for the HRSG and plume frequency and plume size for the cooling tower and coal dryer exhausts. This model provides conservative estimates of both plume frequency and plume size. This model utilizes hourly HRSG, coal dryer, and cooling tower exhaust parameters and hourly ambient condition data to determine the plume

[68] Analysis conducted by Joseph Hughes and William Walters (March 2013).

frequency. This model is based on the algorithms of the Industrial Source Complex model (Version 2), that determine conditions at the plume centerline, but this model does not incorporate building downwash.

The modeling method combines the cooling tower cell exhausts into an equivalent single stack. This method may overestimate cooling tower plume size (particularly height) during plume hours with higher winds due to little cell interaction and the potential for building downwash, but will be more accurate during low wind and calm periods when the exhausts from the cooling tower cells will combine into one coherent body. Wind speeds are set to 1 m/s during calm hours.

The Seasonal/Annual Cooling Tower Impacts (SACTI) model was used to determine frequency and direction of potential plume ground fogging events that could impact traffic safety, in this case Adohr Road, Dairy Road and Tupman Road, adjacent to the project site.

CLOUD COVER DATA ANALYSIS METHOD

A plume frequency of 20 percent of seasonal (November through April) daylight no rain/fog high visual contrast (i.e. “clear”) hours is used to determine potential plume impact significance. The methodology used to determine high visual contrast hours is provided below:

> Energy Commission staff has identified a “clear” sky category during which visible plumes have the greatest potential to cause adverse visual impacts. For this project the meteorological data set[69] used in the analysis categorizes sky cover in 10 percent increments. Staff has included in the “Clear” category a) all hours with sky cover equal to or less than 10 percent plus b) half of the hours with total sky cover 20-90 percent. The rationale for including these two components in this category is as follows: a) visible plumes typically contrast most with sky under clear conditions and, when total sky cover is equal to or less than 10 percent, clouds either do not exist or they make up such a small proportion of the sky that conditions appear to be virtually clear; and b) for a substantial portion of the time when total sky cover is 20-90 percent the opacity of sky cover is relatively low (equal to or less than 50 percent), so this sky cover does not always substantially reduce contrast with visible plumes; staff has estimated that approximately half of the hours meeting the latter sky cover criteria can be considered high visual contrast hours and are included in the “clear” sky definition.

If it is determined that the seasonal daylight clear hour plume frequency is greater than 20 percent then plume dimensions are calculated, and a significance analysis of the plumes is included in the **Visual Resources** section of the Staff Assessment.

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[69] This analysis uses four years (2005-2008) of meteorological data from Bakersfield provided by the applicant. Hours with missing data were excluded.

COOLING TOWER VISIBLE PLUME MODELING ANALYSIS

AIR SEPARATION UNIT COOLING TOWER DESIGN AND OPERATING PARAMETERS

The following cooling tower design characteristics, presented below in **Visible Plume Table 1**, were determined through a review of the applicant's Amended AFC (HECA 2012e), modeling files (HECA 2012d), and data responses (HECA 2012q). The data presented in **Visible Plume Table 1** was used to model the air separation unit (ASU) cooling tower plume frequency and dimensions.

Visible Plume Table 1
ASU Cooling Tower Operating and Exhaust Parameters[a]

Parameter		Cooling Tower Design Parameters		
Number of Cells per Tower		4 Cells (1 by 4 Linear Design)		
Cell Height		16.76 meters (55 feet)		
Cell Stack Diameter		9.14 meters (30 feet)		
Tower Housing Length		60.70 meters (199 feet)		
Tower Housing Width		18.29 meters (60 feet)		
Case	**Inlet Air Ambient Condition**	**Heat Rejection Rate (MW/hr)**	**Exhaust Flow Rate (klbs/hr)**	**Exhaust Temperature (°F)**
3 Cells	39°F, 82% RH	89.8	14,922	84
4 Cells	65°F, 55% RH	90.8	20,052	75
4 Cells	97°F, 20% RH	90.6	19,741	71

Source: HECA 2012e, Section 5.11, Table 5.11-9, and Staff calculations.
Notes:
a. Values were extrapolated or interpolated between hourly ambient condition data points.

AIR SEPARATION UNIT COOLING TOWER VISIBLE PLUME MODELING RESULTS

Visible Plume Table 2 provides the CSVP model visible plume frequency results for year round full load operation using a four-year (2005-2008) Bakersfield meteorological data set.

Visible Plume Table 2
Predicted Hours with ASU Cooling Tower Visible Plumes
Year Round Full Load Operation
Bakersfield 2005-2008 Meteorological Data

CASE	Available (hr)	Plume (hr)	Percent (%)
All Hours	35,006	12,528	36%
Daylights Hours	17,658	4,044	23%
Daylight No Rain No Fog	17,418	3,889	22%
Seasonal Daylight Hours*	7,976	3,646	46%
Seasonal Daylight No Rain No Fog*	7,765	3,504	45%
Seasonal Daylight Clear**	6,041	2,254	37%

*Seasonal conditions occur anytime from November through April.
**Available hours based on seasonal daylight clear hours.

Since the plume frequency is above 20% of the seasonal daylight clear conditions, the corresponding plume dimensions were estimated. The plume dimensions are estimated by the CSVP model and presented in Visible Plume Table 3.

Visible Plume Table 3
Predicted ASU Cooling Tower Visible Plume Dimensions

	ASU Cooling Tower Seasonal "Clear" Hours Plume Dimensions in Meters (feet)		
Percentile	**Length**	**Height**	**Width**
1%	137.18 (450.06)	239.45 (785.60)	55.78 (182.99)
5%	92.77 (304.36)	150.09 (492.43)	40.59 (133.15)
10%	74.54 (244.54)	114.27 (374.89)	34.69 (113.80)
15%	57.59 (188.93)	96.10 (315.27)	28.56 (93.71)
20%	**43.41 (142.42)**	**84.01 (275.61)**	**23.69 (77.73)**
30%	35.33 (115.92)	70.74 (232.08)	21.23 (69.65)

*Results include the cooling tower stack height of 16.76 meters (55 feet), see Visible Plume Table 1.

The plume dimension results shown in **Visible Plume Table 3** correspond only to the defined daylight “clear” weather conditions. The cooling tower plumes can be much larger than those indicated in the table on occasion, particularly during weather events such as rain or fog, or early in morning or at night when it is cold, the relative humidity is high, and the winds are low or dead calm.

AIR SEPARATION UNIT COOLING TOWER GROUND FOGGING MODELING RESULTS

Visible Plume Table 4 provides the worst case hours of plume ground fogging modeled using SACTI model. Staff modeled different operating conditions to determine worst case impacts. The worst case impacts for the ASU cooling tower was at colder ambient conditions when 3 of the 4 cells would be in operation.

The center of ASU cooling tower is located approximately 1,050 meters south of the intersection of Dairy Road and Adohr Road, and 1,520 meters west of Tupman Road. Ground fogging plume is predicted only up to 500 meters away from the center of the 4-cell cooling tower for less than one hour for the four years of meteorological data modeled. Therefore, there would be no interference with traffic visibility on any road.

Visible Plume Table 4
Hours of Ground Fogging Plumes
Year Round Full Load Operation
Bakersfield 2005-2008 Meteorological Data

Distance from Tower (m)	Wind From															
	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
	Plume Heading															
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE
100	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
200	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	1.6	0.0
300	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	2.0	0.0
400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	2.0	0.0
500	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.9	0.0

13-CELL PROCESS COOLING TOWER AND 12-CELL POWER BLOCK COOLING TOWER DESIGN AND OPERATING PARAMETERS

The following cooling tower design characteristics, presented below in **Visible Plume Table 5** and **Visible Plume Table 6**, were determined through a review of the applicant's AFC (HECA 2012e), modeling files (HECA 2012d), and data responses (HECA 2012q). The data presented in **Visible Plume Table 5** and **Visible Plume Table 6** was used to model the 13-cell process cooling tower and adjacent 12-cell power block cooling tower plume frequency and dimensions. Because the two cooling towers have similar exhaust parameters and are adjoined linearly, staff modeled the two towers as one 25-cell linear cooling tower to determine conservative plume frequency and dimension results.

Visible Plume Table 5
13-Cell Process Cooling Tower Operating and Exhaust Parameters[a]

Parameter		Cooling Tower Design Parameters		
Number of Cells per Tower		13 Cells (1 by 13 Linear Design)		
Cell Height		16.76 meters (55 feet)		
Cell Stack Diameter		9.14 meters (30 feet)		
Tower Housing Length		198 meters (650 feet)		
Tower Housing Width		18.29 meters (60 feet)		
Case	**Inlet Air Ambient Condition**	**Heat Rejection Rate (MW/hr)**	**Exhaust Flow Rate (klbs/hr)**	**Exhaust Temperature (°F)**
10 Cells	39°F, 82% RH	292	48,497	71
13 Cells	65°F, 55% RH	293.7	65,129	75
13 Cells	97°F, 20% RH	294.5	64,197	84

Visible Plume Table 6
12-Cell Power Block Cooling Tower Operating and Exhaust Parameters[a]

Parameter		Cooling Tower Design Parameters		
Number of Cells per Tower		12 Cells (1 by 12 Linear Design)		
Cell Height		16.76 meters (55 feet)		
Cell Stack Diameter		9.14 meters (30 feet)		
Tower Housing Length		183 meters (600 feet)		
Tower Housing Width		18.29 meters (60 feet)		
Inlet Air Ambient Condition	No. Cells in Operation	Heat Rejection Rate (MW/hr)	Exhaust Flow Rate (klbs/hr)	Exhaust Temperature (°F)
Hydrogen Rich Fuel with No Duct Firing				
39°F, 82% RH	9	248.1	45,077	70
65°F, 55% RH	12	253.8	60,310	74
97°F, 20% RH	12	260.9	59,223	83
Hydrogen Rich Fuel with Duct Firing				
39°F, 82% RH	9	269.5	44,767	71
65°F, 55% RH	12	271.1	60,155	75
97°F, 20% RH	12	271.8	59,223	84
Natural Gas with No Duct Firing				
39°F, 82% RH	9	--	--	--
65°F, 55% RH	12	--	--	--
97°F, 20% RH	12	149	81.4	81.4
Natural Gas with Duct Firing				
39°F, 82% RH	9	--	--	--
65°F, 55% RH	12	--	--	--
97°F, 20% RH	12	195.3	85.1	85.1

Source: HECA 2012e, HECA 2012d, HECA 2012q.
Notes:
a. Values were extrapolated or interpolated between hourly ambient condition data points.

13-CELL PROCESS COOLING TOWER AND 12-CELL POWER BLOCK COOLING TOWER VISIBLE PLUME MODELING RESULTS

Visible Plume Table 7 provides the CSVP model visible plume frequency results for year round full load operation using a four-year (2005-2008) Bakersfield meteorological data set.

Visible Plume Table 7
Predicted Hours with 13-Cell Process Cooling Tower Visible Plumes
Year Round Full Load Operation
Bakersfield 2005-2008 Meteorological Data

CASE	Available (hr)	Plume (hr)	Percent (%)
All Hours	35,006	12,528	36%
Daylights Hours	17,658	4,044	23%
Daylight No Rain No Fog	17,418	3,889	22%
Seasonal Daylight Hours*	7,976	3,646	46%
Seasonal Daylight No Rain No Fog*	7,765	3,504	45%
Seasonal Daylight Clear**	6,041	2,254	37%

*Seasonal conditions occur anytime from November through April.
**Available hours based on seasonal daylight clear hours.

Since the plume frequency is above 20% of the seasonal daylight clear hours for the operation with duct firing the corresponding plume dimensions were estimated. The plume dimensions are estimated by the CSVP model and presented in **Visible Plume Table 8**.

Visible Plume Table 8
Predicted 25-Cell Power Block and Process Cooling Tower
Visible Plume Dimensions

	25-Cell Cooling Tower Seasonal "Clear" Hours Plume Dimensions in Meters (feet)		
Percentile	**Length**	**Height**	**Width**
1%	352.29 (1155.80)	284.16 (932.30)	136.95 (449.31)
5%	209.40 (687.02)	185.46 (608.46)	87.91 (288.42)
10%	160.98 (528.16)	149.98 (492.05)	73.40 (240.82)
15%	135.96 (446.08)	131.03 (429.89)	64.69 (212.24)
20%	**107.51 (352.72)**	**119.83 (393.13)**	**56.79 (186.31)**
30%	97.28 (319.16)	105.22 (345.20)	54.33 (178.25)

*Results include the cooling tower stack height of 16.76 meters (55 feet), see Visible Plume Tables 5 and 6.

The plume dimension results shown in **Visible Plume Table 8** correspond only to the defined daylight “clear” weather conditions. The cooling tower plumes can be much larger than those indicated in the table on occasion, particularly during weather events such as rain or fog, or early in morning or at night when it is cold, the relative humidity is high, and the winds are low or dead calm.

13-CELL PROCESS COOLING TOWER AND 12-CELL POWER BLOCK COOLING TOWER GROUND FOGGING MODELING RESULTS

Visible Plume Table 9 provides the SACTI model predicted hours of plume ground fogging with various wind directions. Staff modeled different operating conditions to determine worst case impacts. The worst case impacts for the 12-cell and 13-cell cooling towers was at colder ambient conditions when a total of 19 of the 25 cells would be in operation. Staff assumed complete plume merging from the two towers and modeled them as a single source.

The center of the 25-cell cooling tower is located approximately 1,280 meters south of Adohr Road, and 890 meters west of Tupman Road. Ground fogging plume is not predicted to reach these distances in the directions of the nearby roads. Therefore, there would be no interference with traffic visibility on any road. Ground fogging plume is predicted to reach up to 1,300 meters away from the center of the 25-cell cooling tower heading in the south-south east direction. However, ground fogging plumes exceeding 1,000 meters were only predicted to occur approximately 30 minutes out of the four years of meteorological data modeled and ground fogging plumes reaching 1,300 meters were only predicted to occur approximately 12 minutes out of the four years of meteorological data modeled.

Visible Plume Table 9
Hours of Ground Fogging Plumes
Year Round Full Load Operation
Bakersfield 2005-2008 Meteorological Data

Distance from Tower (m)	Wind From															
	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
	Plume Heading															
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE
100	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
200	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	0.5
300	0.5	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.0	2.0
400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.0	0.6
500	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.4	0.5
1000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
1300	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2

HRSG AND COAL DRYER VISIBLE PLUME MODELING ANALYSIS

Staff evaluated the Applicant's Amended AFC (HECA 2012e) and performed an independent psychrometric analysis. The Combustion Stack Visible Plume (CSVP) model was used to estimate the worst-case potential plume frequency for the proposed HRSG and coal dryer stacks.

HRSG PARAMETERS

Based on the stack exhaust parameters anticipated by the Applicant, the frequency of visual plumes can be estimated. The operating data for these stacks are provided in **Visible Plume Table 10**.

Visible Plume Table 10
HRSG Exhaust Parameters[a]

Parameter	HRSG Exhaust Parameters		
Stack Height	65 meters (213 feet)		
Stack Diameter	7 meters (23 feet)		
Ambient Conditions	Moisture Content (% by weight)	Exhaust Flow Rate (klbs/hr)	Exhaust Temp (°F)
Hydrogen Rich Fuel with No Duct Firing			
39°F	6.4	3,956	200
65°F	7.0	3,747	200
97°F	7.5	3,496	200

Visible Plume Table 10
HRSG Exhaust Parameters[a]

Hydrogen Rich Fuel with Duct Firing			
39°F	7.2	4,876	200
65°F	7.8	4,712	200
97°F	8.3	4,575	200

Source: HECA 2012e, HECA 2012d, HECA 2012q.
Note:
a. Values were extrapolated or interpolated between hourly ambient condition data points as necessary.

HRSG VISIBLE PLUME MODELING ANALYSIS

Staff modeled the HRSG plumes using the CSVP model with a four-year meteorological data set from Bakersfield. **Visible Plume Table 11** provides the CSVP model visible plume frequency results for full load operations, with and without duct firing.

Visible Plume Table 11
Staff Predicted Hours with HRSG Steam Plumes
Bakersfield 2005-2008 Meteorological Data

Case	Available (hr)	Full Load with Duct Firing		Full Load with No Duct Firing	
		Plume (hr)	Percent	Plume (hr)	Percent
Hydrogen Rich Fuel					
All Hours	35,006	5,078	15%	3,095	9%
Daylight Hours	17,658	1,090	6%	579	3%
Daylight No Rain No Fog	17,418	1,039	6%	556	3%
Seasonal Daylight Hours*	7,976	1,081	14%	578	7%
Seasonal Daylight No Rain No Fog*	7,765	1,032	13%	555	7%
Seasonal Daylight Clear**	6,041	525	9%	251	4%

*Seasonal conditions occur anytime from November through April.
**Available hours based on seasonal daylight clear hours.

Since the plume frequency is below 20% of the seasonal daylight clear hours for the operation with and without duct firing the corresponding plume dimensions were not estimated.

COAL DRYER PARAMETERS

Based on the stack exhaust parameters anticipated by the Applicant, the frequency of visual plumes can be estimated. The operating data for this stack is provided in **Visible Plume Table 12**.

Visible Plume Table 12
Coal Dryer Exhaust Parameters

Parameter	HRSG Exhaust Parameters		
Stack Height	92.96 meters (305 feet)		
Stack Diameter	4.88 meters (16 feet)		
Ambient Conditions	Moisture Content (% by weight)	Exhaust Flow Rate (klbs/hr)	Exhaust Temp (°F)
39°F	10.8	800	200
65°F	10.8	800	200
97°F	10.8	800	200

Source: HECA 2012e, HECA 2012d, HECA 2012q.

COAL DRYER VISIBLE PLUME MODELING ANALYSIS

Staff modeled the coal dryer plumes using the CSVP model with a four-year meteorological data set from Bakersfield. **Visible Plume Table 13** provides the CSVP model visible plume frequency results for full load operations.

Visible Plume Table 13
Staff Predicted Hours with Coal Dryer Visible Plumes
Bakersfield 2005-2008 Meteorological Data

CASE	Available (hr)	Plume (hr)	Percent (%)
All Hours	35,006	13,199	38%
Daylights Hours	17,658	4,266	24%
Daylight No Rain No Fog	17,418	4,094	24%
Seasonal Daylight Hours*	7,976	3,939	49%
Seasonal Daylight No Rain No Fog*	7,765	3,781	47%
Seasonal Daylight Clear*	6,041	2,442	40%

*Seasonal conditions occur anytime from November through April.
**Available hours based on seasonal daylight clear hours.

Since the plume frequency is above 20% of the seasonal daylight clear hours for the operation the corresponding plume dimensions were estimated. The plume dimensions are estimated by the CSVP model and presented in **Visible Plume Table 14**.

Visible Plume Table 14
Predicted Coal Dryer Visible Plume Dimensions Firing

	Coal Dryer Seasonal "Clear" Hours Plume Dimensions in Meters (feet)		
Percentile	**Length**	**Height**	**Width**
1%	177.61 (582.65)	303.88 (996.89)	69.09 (226.65)
5%	91.47 (300.07)	227.08 744.94)	39.04 (128.06)
10%	63.22 (207.38)	196.97 (646.15)	30.43 (99.84)
15%	48.59 (159.39)	180.75 (592.95)	25.88 (84.88)
20%	**40.23 (131.96)**	**168.81 (553.79)**	**22.22 (72.89)**
30%	38.55 (126.47)	154.66 (507.37)	20.66 (67.78)

*Results include the coal dryer stack height of 92.96 meters (305 feet), see VISIBLE PLUME Table 16.

The plume dimension results shown in **Visible Plume Table 14** correspond only to the defined daylight “clear” weather conditions. The cooling tower plumes can be much larger than those indicated in the table on occasion, particularly during weather events such as rain or fog, or early in morning or at night when it is cold, the relative humidity is high, and the winds are low or dead calm.

CONCLUSIONS

Visible water vapor plumes from all of the proposed HECA cooling towers are predicted to occur more than 20 percent of seasonal daylight clear hours considering the worst-case maximum facility operation. Therefore, further visual impact analysis of the expected twenty percentile plume size has been completed for each cooling tower.

The ground fogging plume analysis predicts that ground fogging plumes from the proposed process cooling tower and power block cooling tower could reach the nearby Tupman Road during worst case merging conditions. However, the model predicts very low frequencies at distances that could reach roads over the four years of meteorological data modeled.

Visible water vapor plumes from the proposed HECA gas turbine/HRSG exhausts would likely not occur more than 20 percent of seasonal daylight clear hours, therefore, no further visual impact analysis was completed.

Visible water vapor plumes from the proposed HECA coal dryer exhaust would likely occur more than 20 percent of seasonal daylight clear hours. Therefore, further visual impact analysis of the expected twenty percentile plume size has been completed.

REFERENCES

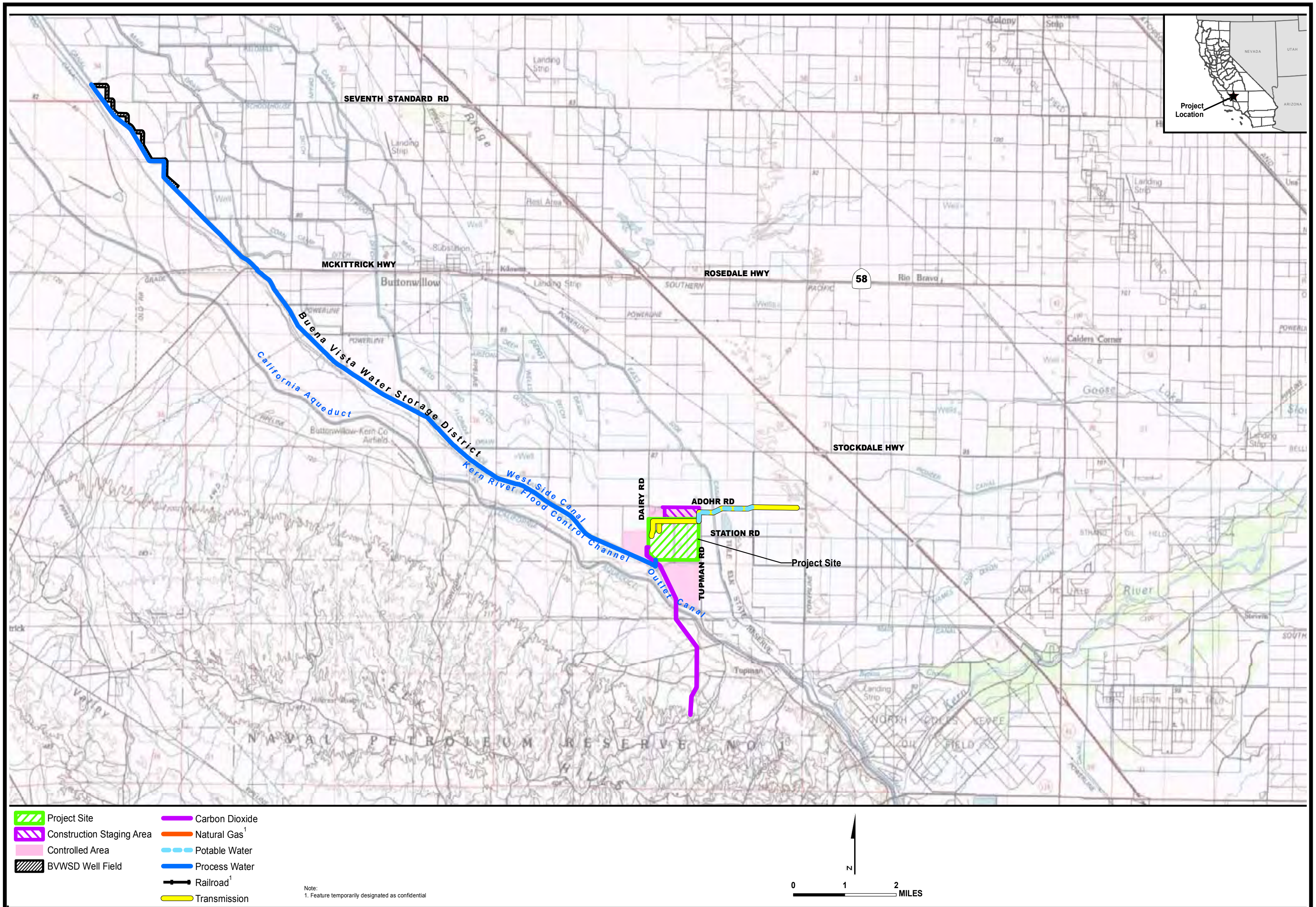
CEC 2012h – California Energy Commission/R. Worl (tn 66281). Data Request Set 1; A1 - A123, dated 07/20/2012. Submitted to Dockets on 07/20/2012.

HECA 2012d – SCS Energy California, LLC/URS/D. Shileikis (tn 65046). Air Quality Modeling Files for the Amended AFC, dated 05/02/2012. Submitted to CEC Docket Unit on 05/02/2012.

HECA 2012e – SCS Energy California, LLC (tn 65049). Amended Application for Certification; Vols. I, II, and III (08-AFC-8A), dated 05/02/12. Submitted to CEC Docket Unit on 05/02/2012.

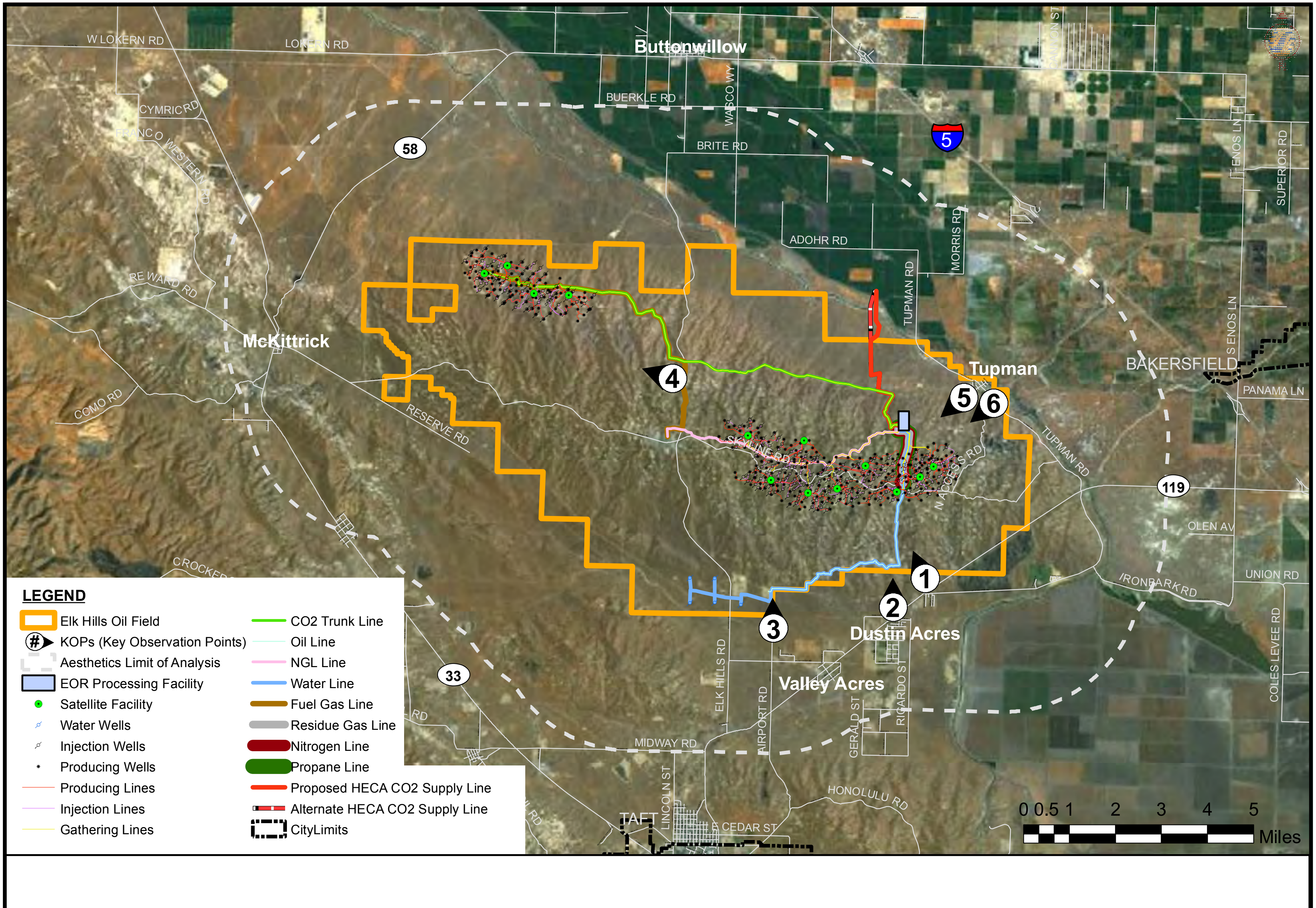
HECA 2012q – SCS Energy California, LLC/URS/D. Shileikis (tn 66876). Response to CEC's Data Request Set 1; A1 - A123, dated 08/22/2012. Submitted to CEC Docket Unit on 08/22/2012.

VISUAL RESOURCES - FIGURE 1
Hydrogen Energy California - Project Location



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: 08 AFC-8A - Figure 2-7

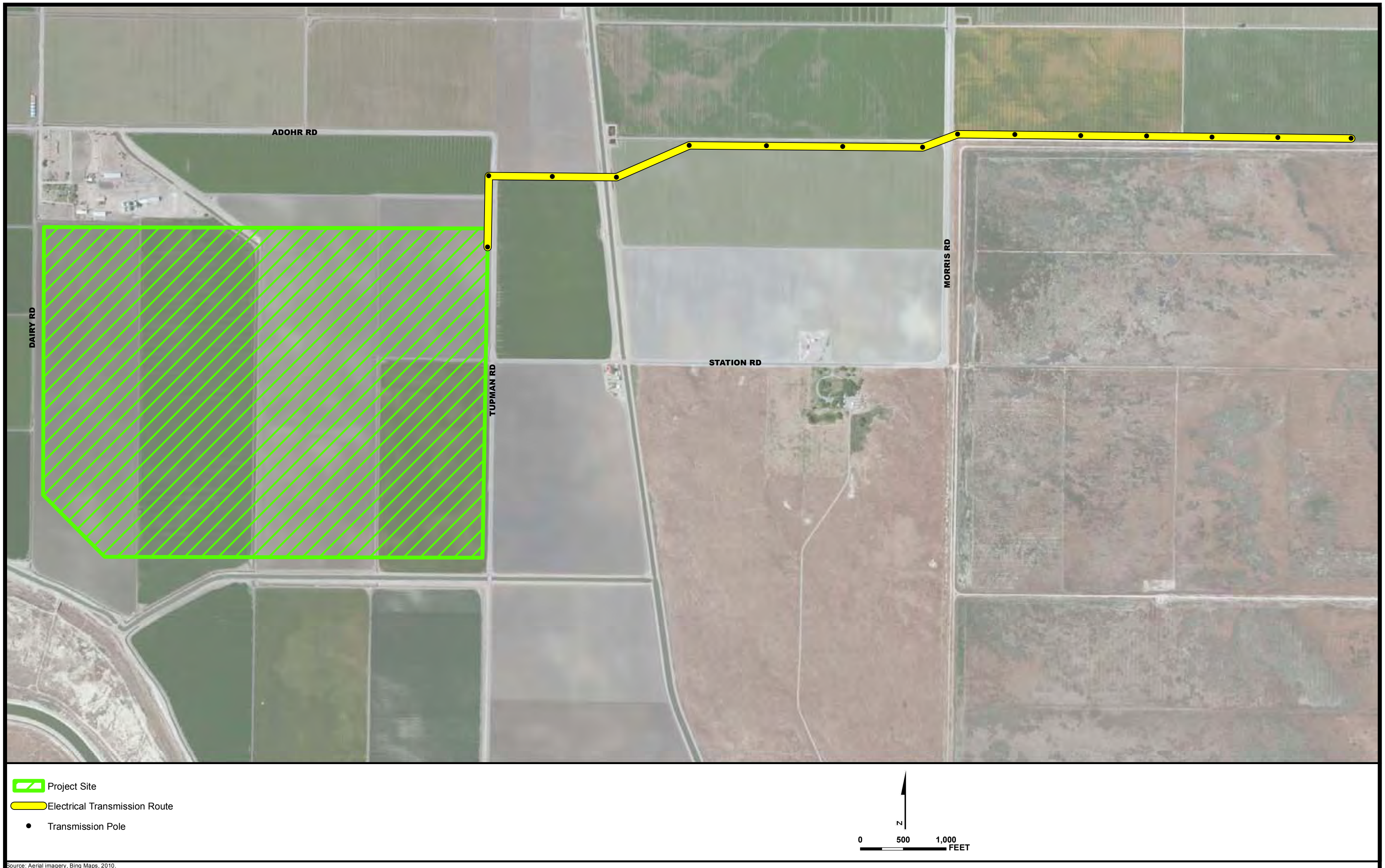
VISUAL RESOURCES - FIGURE 2
Occidental of Elk Hills, Inc. (OEHI) - Site Location



VISUAL RESOURCES

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: Appendix A

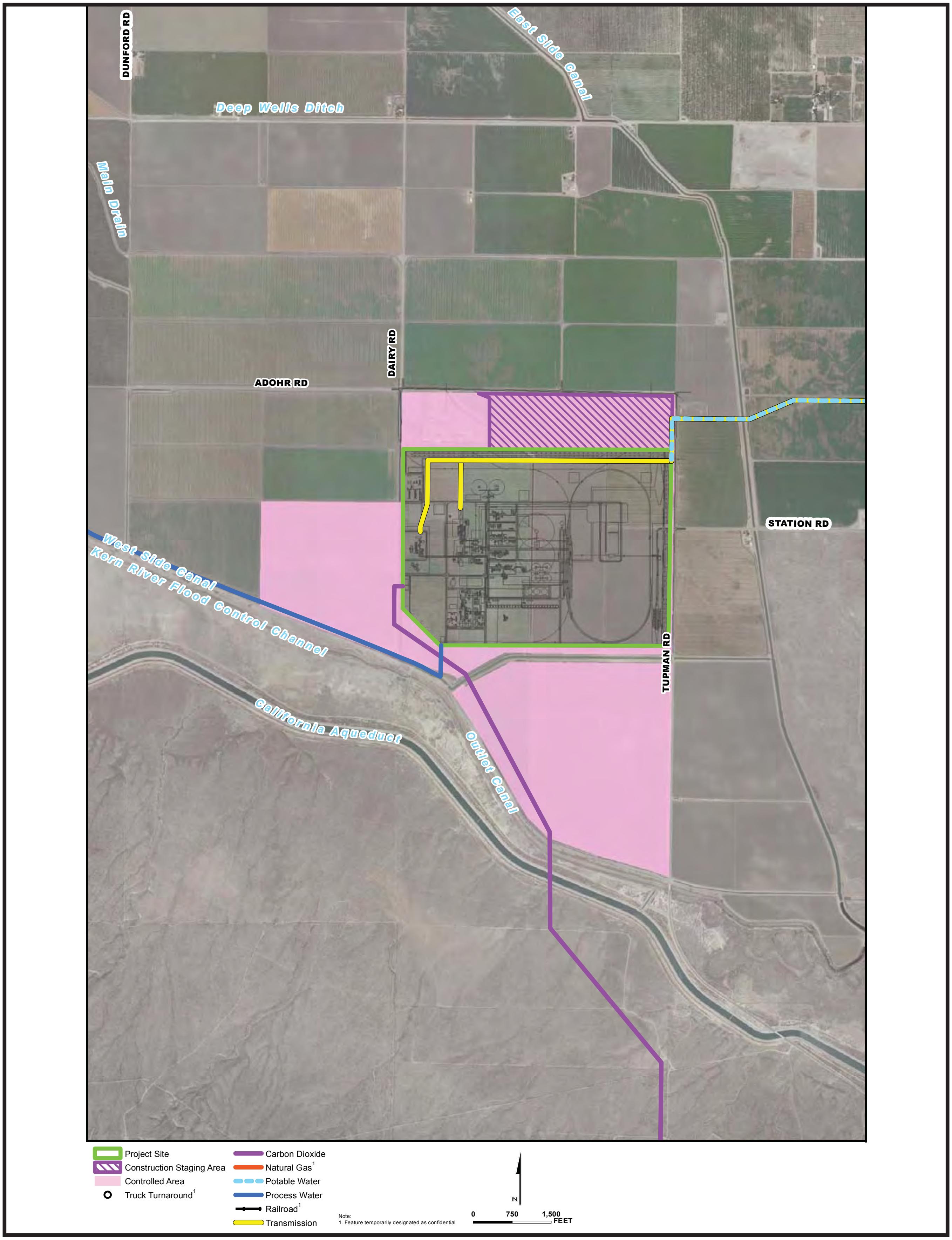
VISUAL RESOURCES - FIGURE 3
Hydrogen Energy California - Electrical Transmission Route



SOURCE: 08 AFC-8A - Figure 4-1

VISUAL RESOURCES- FIGURE 4

Hydrogen Energy California - Project Site Plan

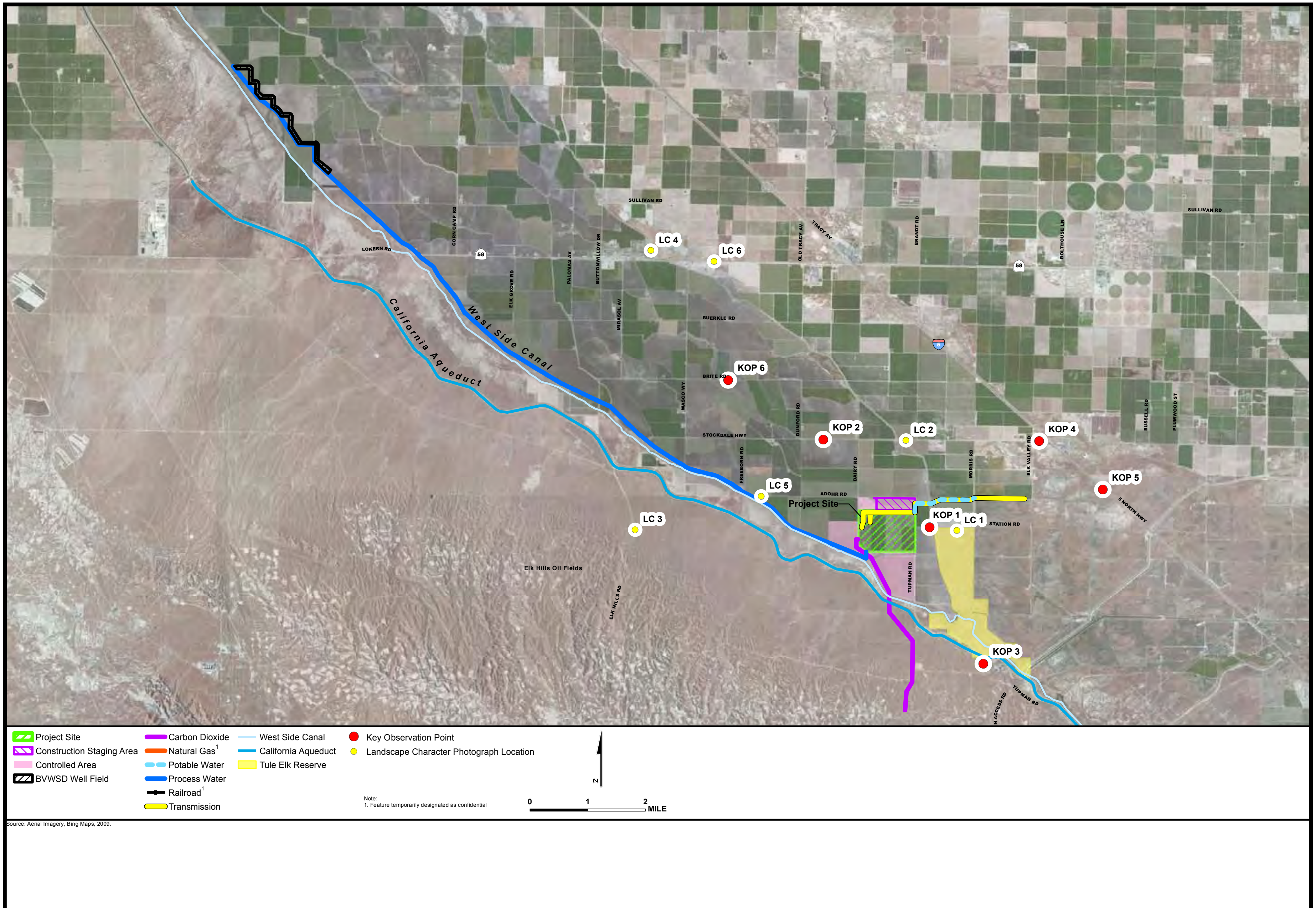


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: 08 AFC-8A - Figure 2-4

VISUAL RESOURCES - FIGURE 5

Hydrogen Energy California - Map of KOPs

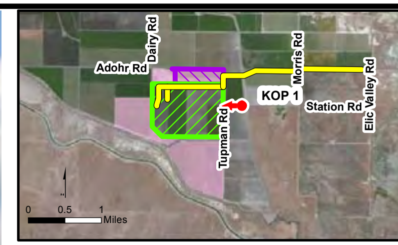


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: 08 AFC-8A - Figure 5.11-2

VISUAL RESOURCES - FIGURE 6a

Hydrogen Energy California - KOP 1, View of the HECA Project Site, Looking West from Station Road (Existing Condition)



Key Observation Point

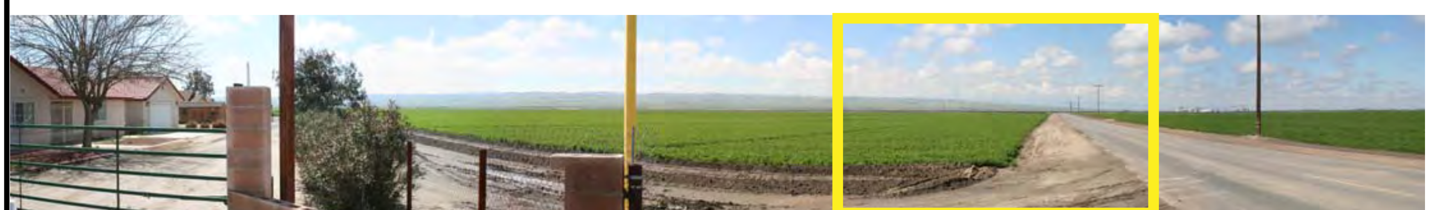
Transmission

Project Site

Construction Staging Area

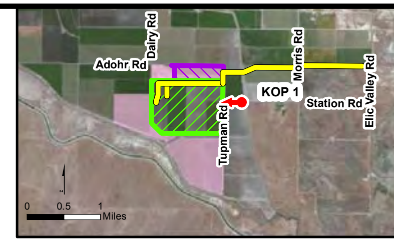
Controlled Area

Photograph is intended to be viewed 10 inches from viewer's eyes when printed on 11x17 paper. The photograph below has been cropped top and bottom to show a wide angle of view with the above photograph's area shown in yellow.



VISUAL RESOURCES - FIGURE 6b

Hydrogen Energy California - KOP 1, View of the HECA Project Site, Looking West from Station Road (Proposed Condition)



Key Observation Point

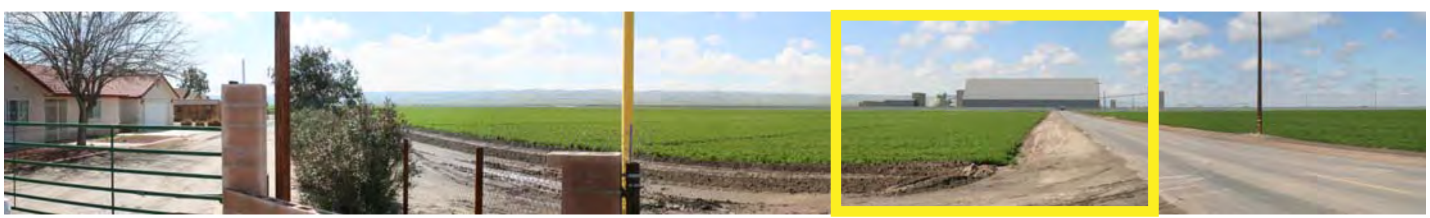
Transmission

Project Site

Construction Staging Area

Controlled Area

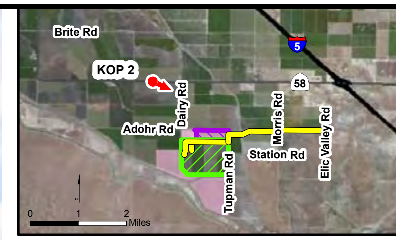
Photograph is intended to be viewed 10 inches from viewer's eyes when printed on 11x17 paper. The photograph below has been cropped top and bottom to show a wide angle of view with the above photograph's area shown in yellow.



VISUAL RESOURCES

VISUAL RESOURCES - FIGURE 7a

Hydrogen Energy California - KOP 2, View of the HECA Project Site, Looking South-Southeast from Stockdale Highway (Existing Condition)



Key Observation Point
Transmission
Project Site
Construction Staging Area
Controlled Area

Photograph is intended to be viewed 10 inches from viewer's eyes when printed on 11x17 paper. The photograph below has been cropped top and bottom to show a wide angle of view with the above photograph's area shown in yellow.

VISUAL RESOURCES

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: 08 AFC-8A - Figure 5.11-17

VISUAL RESOURCES - FIGURE 7b

Hydrogen Energy California - KOP 2, View of the HECA Project Site, Looking South-Southeast from Stockdale Highway (Proposed Condition)

Key Observation Point

Transmission

Project Site

Construction Staging Area

Controlled Area

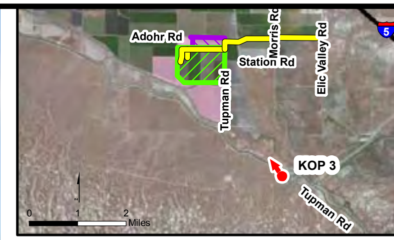
Photograph is intended to be viewed 10 inches from viewer's eyes when printed on 11x17 paper. The photograph below has been cropped top and bottom to show a wide angle of view with the above photograph's area shown in yellow.

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: 08 AFC-8A - Figure 5.11-18

VISUAL RESOURCES - FIGURE 8a

Hydrogen Energy California - KOP 3, View of the HECA Project Site, Looking North-Northwest from the Elk Hills Elementary School Playground (Existing Condition)



Key Observation Point

Transmission

Project Site

Construction Staging Area

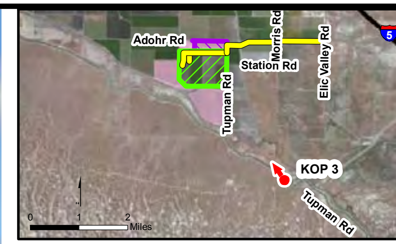
Controlled Area

Photograph is intended to be viewed 10 inches from viewer's eyes when printed on 11x17 paper. The photograph below has been cropped top and bottom to show a wide angle of view with the above photograph's area shown in yellow.

SOURCE: 08 AFC-8A - Figure 5.11-19

VISUAL RESOURCES - FIGURE 8b

Hydrogen Energy California - KOP 3, View of the HECA Project Site, Looking North-Northwest from the Elk Hills Elementary School Playground (Proposed Condition)



Key Observation Point

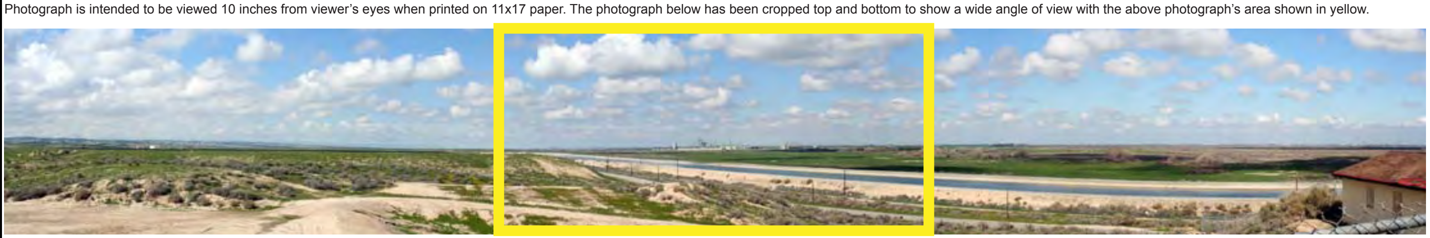
Transmission

Project Site

Construction Staging Area

Controlled Area

Photograph is intended to be viewed 10 inches from viewer's eyes when printed on 11x17 paper. The photograph below has been cropped top and bottom to show a wide angle of view with the above photograph's area shown in yellow.



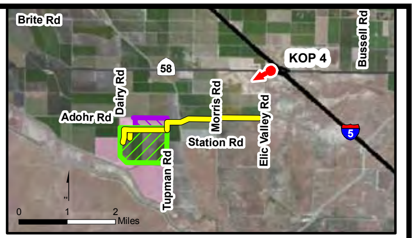
VISUAL RESOURCES

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: 08 AFC-8A - Figure 5.11-20

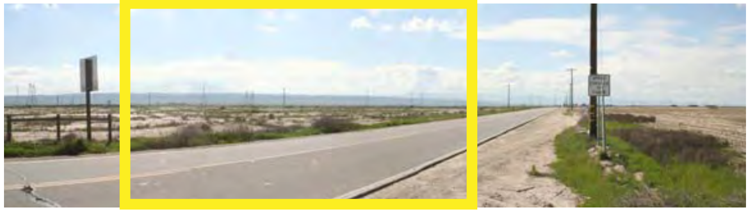
VISUAL RESOURCES - FIGURE 9a

Hydrogen Energy California - KOP 4, View of the HECA Project Site, Looking South-Southwest from the Stockdale Highway near the I-5 Interchange (Existing Condition)



Key Observation Point
Transmission
Project Site
Construction Staging Area
Controlled Area

Photograph is intended to be viewed 10 inches from viewer's eyes when printed on 11x17 paper. The photograph below has been cropped top and bottom to show a wide angle of view with the above photograph's area shown in yellow.



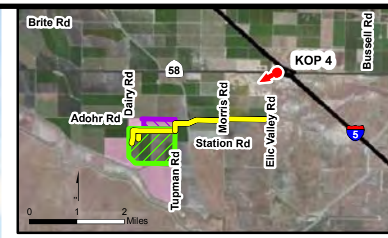
VISUAL RESOURCES

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: 08 AFC-8A - Figure 5.11-21

VISUAL RESOURCES - FIGURE 9b

Hydrogen Energy California - KOP 4, View of the HECA Project Site, Looking South-Southwest from the Stockdale Highway near the I-5 Interchange (Proposed Condition)



Key Observation Point

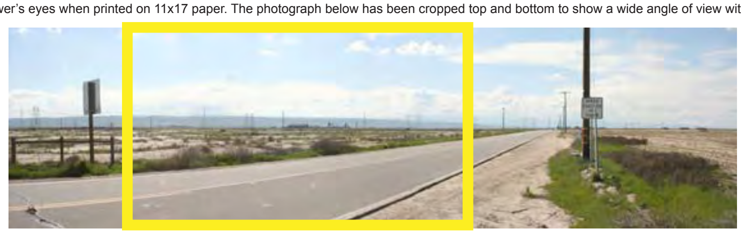
Transmission

Project Site

Construction Staging Area

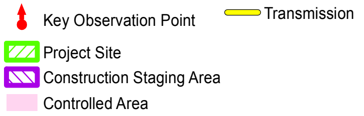
Controlled Area

Photograph is intended to be viewed 10 inches from viewer's eyes when printed on 11x17 paper. The photograph below has been cropped top and bottom to show a wide angle of view with the above photograph's area shown in yellow.



VISUAL RESOURCES - FIGURE 10a

Hydrogen Energy California - KOP 6, View of the HECA Project Site, Looking South-Southeast from Brite Road (Existing Condition)



Photograph is intended to be viewed 10 inches from viewer's eyes when printed on 11x17 paper. The photograph below has been cropped top and bottom to show a wide angle of view with the above photograph's area shown in yellow.

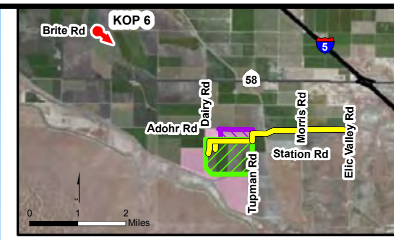
VISUAL RESOURCES

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: 08 AFC-8A - Figure 5.11-25

VISUAL RESOURCES - FIGURE 10b

Hydrogen Energy California - KOP 6, View of the HECA Project Site, Looking South-Southeast from Brite Road (Proposed Condition)



Photograph is intended to be viewed 10 inches from viewer's eyes when printed on 11x17 paper. The photograph below has been cropped top and bottom to show a wide angle of view with the above photograph's area shown in yellow.

VISUAL RESOURCES - FIGURE 11a

Hydrogen Energy California - KOP 1 - View of the OEHI Site, Looking North-Northwest from the Intersection of Highway 119 and Golf Course Road (Existing Condition)

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: TN 69388 02-05-13 Applicant OEHI Responses to CEC Set 3 Data Requests Nos. A178 - 180, Appendix A - Fig. A1-A

VISUAL RESOURCES - FIGURE 11b

Hydrogen Energy California - KOP 1 - View of the OEHI Site, Looking North-Northwest from the Intersection of Highway 119 and Golf Course Road (Proposed Condition)

VISUAL RESOURCES

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: TN 69388 02-05-13 Applicant OEHI Responses to CEC Set 3 Data Requests Nos. A178 - 180, Appendix A - Fig. A1-B

VISUAL RESOURCES - FIGURE 12a

Hydrogen Energy California - KOP 2 - View of the OEHI Site, Looking North from the Intersection of Highway 119 and Tank Farm Road (Existing Condition)

SOURCE: TN 69388 02-05-13 Applicant OEHI Responses to CEC Set 3 Data Requests Nos. A178 - 180, Appendix A - Fig. A2-A

VISUAL RESOURCES - FIGURE 12b

Hydrogen Energy California - KOP 2 - View of the OEHI Site, Looking North from the Intersection of Highway 119 and Tank Farm Road (Proposed Condition)

SOURCE: TN 69388 02-05-13 Applicant OEHI Responses to CEC Set 3 Data Requests Nos. A178 - 180, Appendix A - Fig. A2-B

VISUAL RESOURCES - FIGURE 13a

Hydrogen Energy California - KOP 3 - View of the OEHI Site, Looking North from Airport Road (Existing Condition)

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: TN 69388 02-05-13 Applicant OEHI Responses to CEC Set 3 Data Requests Nos. A178 - 180, Appendix A - Fig. A3-A

VISUAL RESOURCES - FIGURE 13b

Hydrogen Energy California - KOP 3 - View of the OEHI Site, Looking North from Airport Road (Proposed Condition)

SOURCE: TN 69388 02-05-13 Applicant OEHI Responses to CEC Set 3 Data Requests Nos. A178 - 180, Appendix A - Fig. A3-B

VISUAL RESOURCES - FIGURE 14a

Hydrogen Energy California - KOP 4 - View of the OEHI Site, Looking Northwest from Elk Hills Road (Existing Condition)

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: TN 69388 02-05-13 Applicant OEHI Responses to CEC Set 3 Data Requests Nos. A178 - 180, Appendix A - Fig. A4-A

VISUAL RESOURCES - FIGURE 14b

Hydrogen Energy California - KOP 4 - View of the OEHI Site, Looking Northwest from Elk Hills Road (Proposed Condition)

SOURCE: TN 69388 02-05-13 Applicant OEHI Responses to CEC Set 3 Data Requests Nos. A178 - 180, Appendix A - Fig. A4-B

VISUAL RESOURCES - FIGURE 15a

Hydrogen Energy California - KOP 5 - View of the OEHI Site, Looking Southwest from Grace Avenue (Existing Condition)

SOURCE: TN 69388 02-05-13 Applicant OEHI Responses to CEC Set 3 Data Requests Nos. A178 - 180, Appendix A - Fig. A5-A

VISUAL RESOURCES - FIGURE 15b

Hydrogen Energy California - KOP 5 - View of the OEHI Site, Looking Southwest from Grace Avenue (Proposed Condition)

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: TN 69388 02-05-13 Applicant OEHI Responses to CEC Set 3 Data Requests Nos. A178 - 180, Appendix A - Fig. A5-B

VISUAL RESOURCES - FIGURE 16a

Hydrogen Energy California - KOP 6 - View of the OEHI Site, Looking South-Southwest from the U.S. Post Office (Existing Condition)

SOURCE: TN 69388 02-05-13 Applicant OEHI Responses to CEC Set 3 Data Requests Nos. A178 - 180, Appendix A - Fig. A6-A

VISUAL RESOURCES - FIGURE 16b

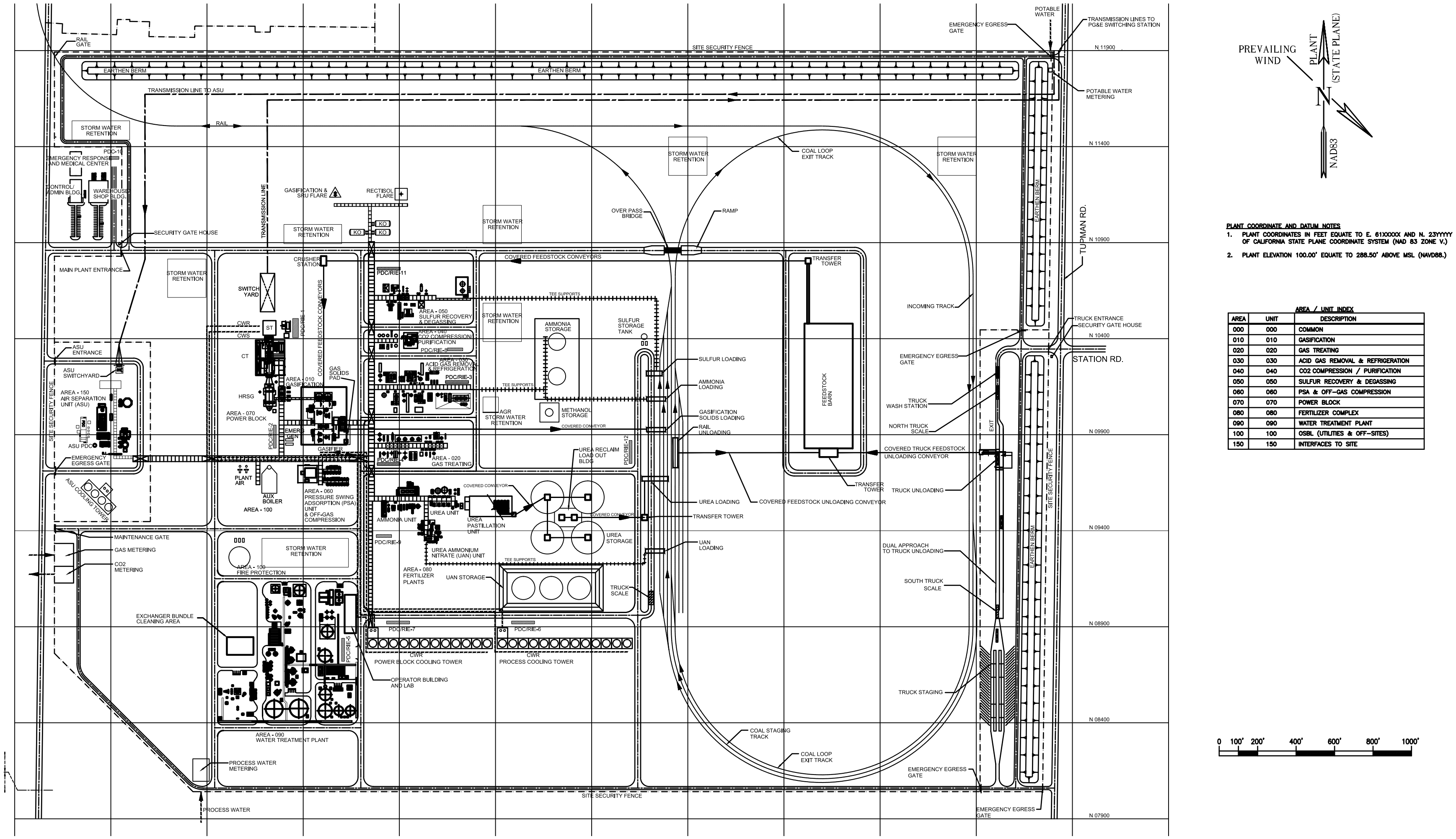
Hydrogen Energy California - KOP 6 - View of the OEHI Site, Looking South-Southwest from the U.S. Post Office (Proposed Condition)

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: TN 69388 02-05-13 Applicant OEHI Responses to CEC Set 3 Data Requests Nos. A178 - 180, Appendix A - Fig. A6-B

VISUAL RESOURCES - FIGURE 17

Hydrogen Energy California - Preliminary Plot Plan



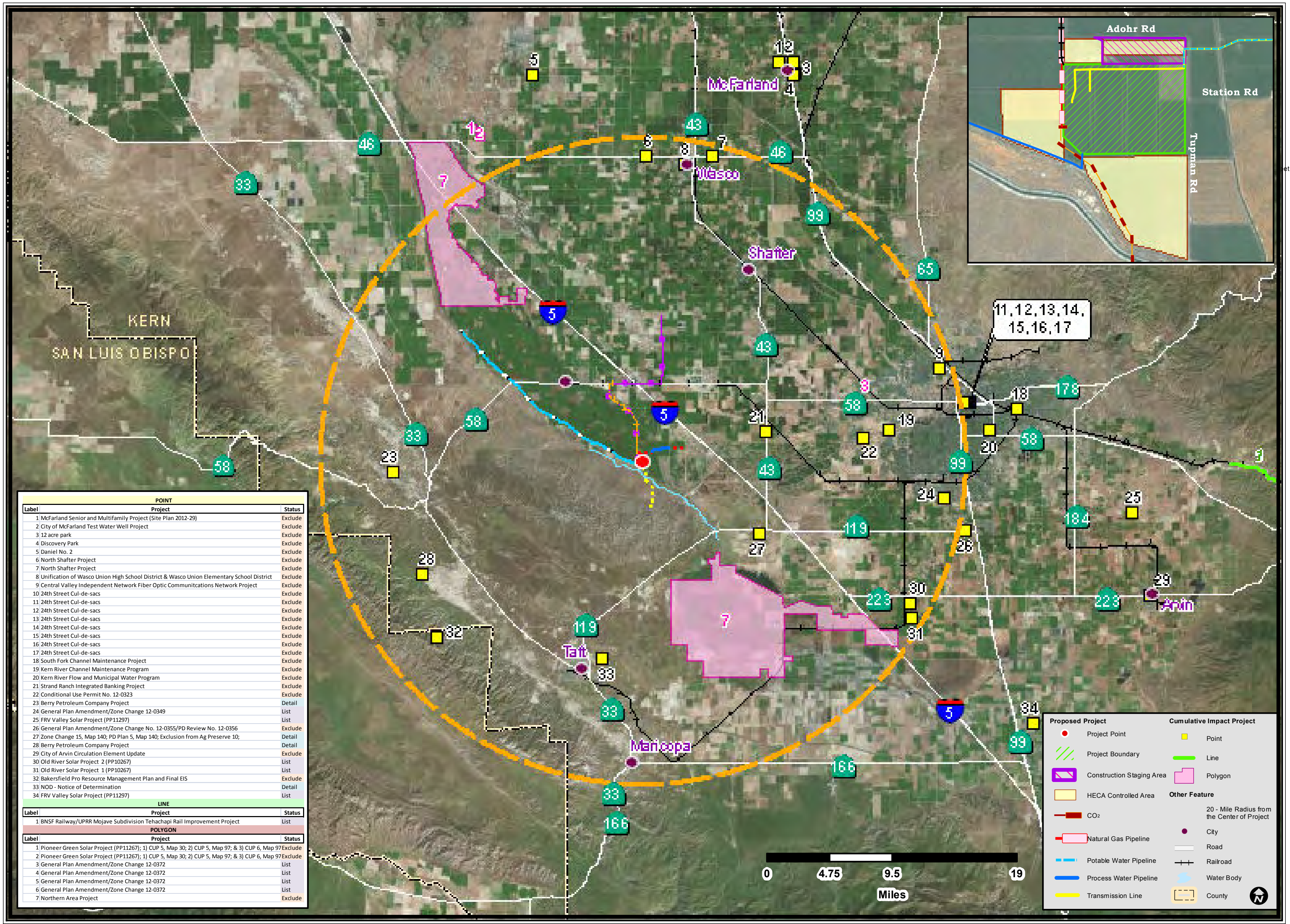
AREA	UNIT	DESCRIPTION
000	000	COMMON
010	010	GASIFICATION
020	020	GAS TREATING
030	030	ACID GAS REMOVAL & REFRIGERATION
040	040	CO2 COMPRESSION / PURIFICATION
050	050	SULFUR RECOVERY & DEGASSING
060	060	PSA & OFF-GAS COMPRESSION
070	070	POWER BLOCK
080	080	FERTILIZER COMPLEX
090	090	WATER TREATMENT PLANT
100	100	OSBL (UTILITIES & OFF-SITES)
150	150	INTERFACES TO SITE

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: 08 AFC-8A - Figure 2-5

VISUAL RESOURCES - FIGURE 18

Hydrogen Energy Project - Cumulative Impacts



POINT

Label	Project	Status
1	McFarland Senior and Multifamily Project (Site Plan 2012-29)	Exclude
2	City of McFarland Test Water Well Project	Exclude
3	12 acre park	Exclude
4	Discovery Park	Exclude
5	Daniel No. 2	Exclude
6	North Shafter Project	Exclude
7	North Shafter Project	Exclude
8	Unification of Wasco Union High School District & Wasco Union Elementary School District	Exclude
9	Central Valley Independent Network Fiber Optic Communitcations Network Project	Exclude
10	24th Street Cul-de-sacs	Exclude
11	24th Street Cul-de-sacs	Exclude
12	24th Street Cul-de-sacs	Exclude
13	24th Street Cul-de-sacs	Exclude
14	24th Street Cul-de-sacs	Exclude
15	24th Street Cul-de-sacs	Exclude
16	24th Street Cul-de-sacs	Exclude
17	24th Street Cul-de-sacs	Exclude
18	South Fork Channel Maintenance Project	Exclude
19	Kern River Channel Maintenance Program	Exclude
20	Kern River Flow and Municipal Water Program	Exclude
21	Strand Ranch Integrated Banking Project	Exclude
22	Conditional Use Permit No. 12-0323	Exclude
23	Berry Petroleum Company Project	Detail
24	General Plan Amendment/Zone Change 12-0349	List
25	FRV Valley Solar Project (PP11297)	List
26	General Plan Amendment/Zone Change No. 12-0355/PD Review No. 12-0356	Exclude
27	Zone Change 15, Map 140; PD Plan 5, Map 140; Exclusion from Ag Preserve 10;	Detail
28	Berry Petroleum Company Project	Detail
29	City of Arvin Circulation Element Update	Exclude
30	Old River Solar Project 2 (PP10267)	List
31	Old River Solar Project 1 (PP10267)	List
32	Bakersfield Pro Resource Management Plan and Final EIS	Exclude
33	NOD - Notice of Determination	Detail
34	FRV Valley Solar Project (PP11297)	List

LINE

Label	Project	Status
1	BNSF Railway/UPRR Mojave Subdivision Tehachapi Rail Improvement Project	List

POLYGON

Label	Project	Status
1	Pioneer Green Solar Project (PP11267); 1) CUP 5, Map 30; 2) CUP 5, Map 97; & 3) CUP 6, Map 97	Exclude
2	Pioneer Green Solar Project (PP11267); 1) CUP 5, Map 30; 2) CUP 5, Map 97; & 3) CUP 6, Map 97	Exclude
3	General Plan Amendment/Zone Change 12-0372	List
4	General Plan Amendment/Zone Change 12-0372	List
5	General Plan Amendment/Zone Change 12-0372	List
6	General Plan Amendment/Zone Change 12-0372	List
7	Northern Area Project	Exclude

CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING DIVISION

SOURCE: OpenStreetMap January 2013, ESRI, Bing Aerial Imagery.

WASTE MANAGEMENT

Ellen Townsend-Hough

SUMMARY OF CONCLUSIONS

The Hydrogen Energy California (HECA) Project would produce thousands of tons per year of waste during the operation of the facility. The majority of the waste would be gasification solids. HECA is expected to generate a maximum of 850 tons per day of gasification waste (vitrified slag). HECA is currently investigating three potential markets for beneficial reuse of this material; 1) roofing granules, 2) blasting grit, 3) pozzolanic admixtures in cement manufacture. The large quantity of waste would significantly impact Kern County landfills and possibly compromise the county's compliance with Public Resources Code section 40000 et seq. and Senate Bill (SB) 1016 (Stats. 2008, ch. 343.) and implementing regulations. The HECA project owner has not produced a comprehensive plan for the reuse and disposal of the gasifier solids. To avoid significant waste management impacts the project owner would have to work with Energy Commission, Kern County and CalRecycle staff to establish an operational waste diversion program. This plan must be completed and approved by the coordinating agencies prior to staff's publication of the Final Staff Assessment. HECA tested the gasification solids and they are considered non-hazardous according to federal standards. California testing standards should be used to determine if the HECA gasification solids are non-hazardous.

The results of soil sampling and analytical testing at the HECA project site indicate there are elevated concentrations of petroleum hydrocarbons and other contaminants affected by previous site activities. Staff is recommending the site be appropriately characterized prior to the Final Staff Assessment. Staff has reviewed the waste management aspects of the Occidental of Elk Hills, Inc. CO_2 Enhanced Oil Recovery (OEHI CO_2 EOR) Project for construction and operation, as described in the Supplemental Environmental Information (SEI) report (HECA 2012e, Volume II). Nonhazardous and hazardous waste would be generated during construction and operation of the OEHI CO_2 EOR. In order to verify that Kern County has enough landfill capacity to accommodate the project's solid waste disposal needs staff requires the project owner to provide information on the quantity of project waste that would be disposed of in local landfills.

The former Naval Petroleum Reserve No.1 (NPR-1) (a.k.a. the Elk Hills Oil Field (EHOF)) was formerly owned by the United States Department of Energy (DOE) and Chevron Oil Company. During their past operations at the EHOF, wastes were disposed of at "legacy waste sites". As a result of the land transfer to Occidental, California Department of Toxic Substances Control (DTSC) entered into a Corrective Action Consent Agreement with DOE for corrective and/or remediation of several of the legacy waste sites within the Elk Hills Oil Field. DOE agreed to head up an environmental and human health risk assessment of the entire site with remediation to address the effects of past practices at the site. The project owner would keep employees, contractors and DTSC aware of health and safety risks when work is proposed on contaminated areas of the project site.

The **Socioeconomic Resources** section has identified an environmental justice population as defined by the 'Environmental Justice: Guidance under the National Environmental Policy Act'. Staff has identified a significant adverse direct and cumulative impact resulting from the operation of the proposed project, but the impact does not significantly or adversely affect the identified environmental justice community.

The proposed HECA project would cause a significant impact because the volume of waste would place Kern County in jeopardy of non-compliance with California mandated diversion/recycling goals (Public Resources Code section 40000 et seq.). The HECA Application for Certification (AFC) indicates that the gasification solids can be recycled/reused, disposed of locally or exported to another state. Determination of beneficial uses or disposal of the gasification solids is dependent on the chemical and physical characteristics of solids. The solids characteristics are variable and dependent on the feedstock and processing methods.

Staff concludes HECA should evaluate characteristics of the gasification solids based on a similar representative facility using the same feedstock and processing methods. They should then conduct a market analysis of potential uses of the solids so some portion of waste can be diverted from landfills. The gasification waste could be excluded from hazardous waste regulations (i.e., 40 CFR Section 261.4 (b) (7) (ii) (F) and Title 22 CCR Section 66261.4(b) (5) (A). However, prior to acceptance of the gasification solids into a Kern County owned and operated landfill the solids must be analyzed and classified as non-hazardous or hazardous waste. If the solids are determined to be hazardous, the amount of hazardous waste would be burdensome to the State of California and disposal would be costly to the applicant. If they are determined to be non-hazardous according to Title 14 regulations, nonhazardous waste quantities generated and/or disposed of in Kern County would count against the County's waste diversion goals. The expected volume of waste would likely result in the Kern County exceeding their state mandated waste diversion goals. The applicant has proposed to export waste for disposal so the diversion goals can be met. However, CalRecycle has indicated Kern County would still be responsible for the waste generated in the county. Staff encourages Kern County and CalRecycle to discuss how Kern County would be able to comply with Title 14, California Code of Regulations sections 18800 through 18814.11. Staff also recommends that the HECA project owner and Kern County work together to design an operational waste diversion program prior to preparation of the Final Staff Assessment.

INTRODUCTION

This Preliminary Staff Assessment/Draft Environmental Impact Statement (PSA/DEIS) presents an analysis of issues associated with wastes generated from the proposed construction and operation of HECA. The technical scope of this analysis encompasses solid wastes existing on site and wastes that would likely be generated during facility construction and operation. Management and discharge of wastewater is addressed in the **Soils and Surface Water** section of this document. Additional information related to waste management may also be covered in the **Worker Safety** and **Hazardous Materials Management** sections of this document.

The California Energy Commission (Energy Commission) staff's objectives in conducting this waste management analysis are to ensure that:

- The management of project wastes would be in compliance with all applicable laws, ordinances, regulations, and standards.

- The disposal of project wastes would not result in significant adverse impacts to existing waste disposal facilities, or result in other waste-related significant adverse effects on the environment.
- Upon project completion, the site would be managed in such a way that project wastes and waste constituents would not pose a significant risk to humans or the environment.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The following federal, state, and local environmental laws, ordinances, regulations and standards (LORS) in **Waste Management Table 1** have been established to ensure the safe and proper management of both solid and hazardous wastes in order to protect human health and the environment. Project compliance with the various LORS is a major component of staff's determination regarding the significance and acceptability of HECA with respect to management of waste.

Waste Management Table 1
Laws, Ordinances, Regulations, and Standards

Applicable Law	Description
Federal	
Title 42, United States Code (U.S.C.), §6901, et seq. Solid Waste Disposal Act of 1965 (as amended and revised by the Resource Conservation and Recovery Act of 1976, et al.)	The Solid Waste Disposal Act, as amended and revised by the Resource Conservation and Recovery Act (RCRA) et al., establishes requirements for the management of solid wastes (including hazardous wastes), landfills, underground storage tanks, and certain medical wastes. The statute also addresses program administration, implementation and delegation to states, enforcement provisions, and responsibilities, as well as research, training, and grant funding provisions. RCRA Subtitle C establishes provisions for the generation, storage, treatment, and disposal of hazardous waste, including requirements addressing: • Generator record keeping practices that identify quantities of hazardous wastes generated and their disposition; • Waste labeling practices and use of appropriate containers; • Use of a manifest when transporting wastes; • Submission of periodic reports to the United States Environmental Protection Agency (U.S. EPA) or other authorized agency; and • Corrective action to remediate releases of hazardous waste and contamination associated with RCRA-regulated facilities. RCRA Subtitle D establishes provisions for the design and operation of solid waste landfills. RCRA is administered at the federal level by the United States Environmental Protection Agency (U.S. EPA) and its 10 regional offices. The Pacific Southwest regional office (Region 9) implements U.S. EPA programs in California, Nevada, Arizona, and Hawaii.
Title 42, U.S.C., §9601, et seq. Comprehensive	The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as *Superfund*, establishes authority and funding mechanisms for cleanup of uncontrolled or abandoned hazardous waste sites, as well as cleanup of accidents, spills, or

Environmental Response, Compensation and Liability Act	emergency releases of pollutants and contaminants into the environment. Among other things, the statute addresses: • Reporting requirements for releases of hazardous substances; • Requirements for remedial action at closed or abandoned hazardous waste sites, and brownfields; • Liability of persons responsible for releases of hazardous substances or waste; and • Requirements for property owners/potential buyers to conduct “all appropriate inquiries” into previous ownership and uses of the property to 1) determine if hazardous substances have been or may have been released at the site, and 2) establish that the owner/buyer did not cause or contribute to the release. A Phase I Environmental Site Assessment is commonly used to satisfy CERCLA “all appropriate inquiries” requirements.
Title 40, Code of Federal Regulations (CFR), Subchapter I – Solid Wastes	These regulations were established by U.S. EPA to implement the provisions of the Solid Waste Disposal Act and RCRA (described above). Among other things, the regulations establish the criteria for classification of solid waste disposal facilities (landfills), hazardous waste characteristic criteria and regulatory thresholds, hazardous waste generator requirements, and requirements for management of used oil and universal wastes. • Part 257 addresses the criteria for classification of solid waste disposal facilities and practices. • Part 258 addresses the criteria for municipal solid waste landfills. • Parts 260 through 279 address management of hazardous wastes, used oil, and universal wastes (i.e., batteries, mercury-containing equipment, and lamps). U.S. EPA implements the regulations at the federal level. However, California is an RCRA-authorized state, so most of the solid and hazardous waste regulations are implemented by state agencies and authorized local agencies in lieu of U.S. EPA.
Title 49, CFR, Parts 172 and 173. Hazardous Materials Regulations	These regulations address the United States Department of Transportation (DOT) established standards for transport of hazardous materials and hazardous wastes. The standards include requirements for labeling, packaging, and shipping of hazardous materials and hazardous wastes, as well as training requirements for personnel completing shipping papers and manifests. Section 172.205 specifically addresses use and preparation of hazardous waste manifests in accordance with Title 40, CFR, Section 262.20.
40 CFR §261.4(b)(7)(ii)(F): Exclusions: Solid Wastes which are Not Hazardous Wastes Coal gasification	This law excludes gasifier ash from coal gasification and process wastewater from coal gasification from being considered as a hazardous waste.
State	
California Health and Safety Code (HSC), Chapter 6.5, §25100, et seq.	This California law creates the framework under which hazardous wastes must be managed in California. The law provides for the development of a state hazardous waste program that administers and implements the provisions of the federal RCRA program. It also provides for the designation of California-only hazardous wastes and development of

Hazardous Waste Control Act of 1972, as amended	standards (regulations) that are equal to or, in some cases, more stringent than federal requirements. The California Environmental Protection Agency (Cal/EPA), Department of Toxic Substances Control (DTSC) administers and implements the provisions of the law at the state level. Certified Unified Program Agencies (CUPAs) implement some elements of the law at the local level.
Title 22, California Code of Regulations (CCR), Division 4.5. Environmental Health Standards for the Management of Hazardous Waste	These regulations establish requirements for the management and disposal of hazardous waste in accordance with the provisions of the California Hazardous Waste Control Act and federal RCRA. As with the federal requirements, waste generators must determine if their wastes are hazardous according to specified characteristics or lists of wastes. Hazardous waste generators must obtain identification numbers; prepare manifests before transporting the waste off site; and use only permitted treatment, storage, and disposal facilities. Generator standards also include requirements for record keeping, reporting, packaging, and labeling. Additionally, while not a federal requirement, California requires that hazardous waste be transported by registered hazardous waste transporters. The standards addressed by Title 22, CCR include: • Identification and Listing of Hazardous Waste (Chapter 11, §66261.1, et seq.). • Standards Applicable to Generator of Hazardous Waste (Chapter 12, §66262.10, et seq.). • Standards Applicable to Transporters of Hazardous Waste (Chapter 13, §66263.10, et seq.). • Standards for Universal Waste Management (Chapter 23, §66273.1, et seq.). • Standards for the Management of Used Oil (Chapter 29, §66279.1, et seq.). • Requirements for Units and Facilities Deemed to Have a Permit by Rule (Chapter 45, §67450.1, et seq.). The Title 22 regulations are established and enforced at the state level by DTSC. Some generator and waste treatment standards are also enforced at the local level by CUPAs.
HSC, Chapter 6.11 §§25404 – 25404.9 Unified Hazardous Waste and Hazardous Materials Management Regulatory Program (Unified Program)	The Unified Program consolidates, coordinates, and makes consistent the administrative requirements, permits, inspections, and enforcement activities of the six environmental and emergency response programs listed below. • Aboveground Petroleum Storage Act requirements for Spill Prevention, Control, and Countermeasure (SPCC) Plans. • Hazardous Materials Release and Response Plans and Inventories (Business Plans). • California Accidental Release Prevention (CalARP) Program. • Hazardous Material Management Plan / Hazardous Material Inventory Statements. • Hazardous Waste Generator / Tiered Permitting Program. • Underground Storage Tank Program. The state agencies responsible for these programs set the standards for

	their programs while local governments implement the standards. The local agencies implementing the Unified Program are known as CUPAs. Note: The Waste Management analysis only considers application of the Hazardous Waste Generator/Tiered Permitting element of the Unified Program.
Title 27, CCR, Division 1, Sub-division 4, Chapter 1, §15100, et seq. Unified Hazardous Waste and Hazardous Materials Management Regulatory Program	While these regulations primarily address certification and implementation of the program by the local CUPAs, the regulations do contain specific reporting requirements for businesses. • Article 9 – Unified Program Standardized Forms and Formats (§§ 15400–15410). • Article 10 – Business Reporting to CUPAs (§§15600–15620).
Hazardous Waste Source Reduction and Management Review Act of 1989 HSC, Division 20, Chapter 6.5, Article 11.9, §25244.12, et seq.	This law was enacted to expand the state's hazardous waste source reduction activities. Among other things, it establishes hazardous waste source reduction review, planning, and reporting requirements for businesses that routinely generate more than 12,000 kilograms (approximately 26,400 pounds) of hazardous waste in a designated reporting year. The review and planning elements are required to be done on a four-year cycle, with a summary progress report due to DTSC every fourth year.
Title 22, CCR, §67100.1 et seq. Hazardous Waste Source Reduction and Management Review	These regulations further clarify and implement the provisions of the Hazardous Waste Source Reduction and Management Review Act of 1989 (noted above). The regulations establish the specific review elements and reporting requirements to be completed by generators subject to the act.
Title 14, CCR, Division 7, §17200, et seq. California Integrated Waste Management Board	These regulations implement the provisions of the California Integrated Waste Management Act (CIWMA) and set forth minimum standards for solid waste handling and disposal. The regulations include standards for solid waste management, as well as enforcement and program administration provisions. • Chapter 3 – Minimum Standards for Solid Waste Handling and Disposal. • Chapter 3.5 – Standards for Handling and Disposal of Asbestos Containing Waste. • Chapter 7 – Special Waste Standards. • Chapter 8 – Used Oil Recycling Program. • Chapter 8.2 – Electronic Waste Recovery and Recycling. Section 40052 of the Public Resources Code, the purpose of California Integrated Waste Management Act of 1989 (CIWMA) is to "reduce, recycle, and reuse solid waste generated in the state to the maximum extent feasible in an efficient and cost-effective manner to conserve water, energy and other natural resources.

Public Resources Code, Division 30, §40000, et seq. California Integrated Waste Management Act of 1989. Title 14, California Code of Regulations, section 18720 et seq.	The California Integrated Waste Management Act of 1989 (as amended) establishes mandates and standards for management of solid waste. Among other things, the law includes provisions addressing solid waste source reduction and recycling, standards for design and construction of municipal landfills, and programs for county waste management plans and local implementation of solid waste requirements. The act was amended in 2011 (AB 341) to include a legislative declaration of a state policy goal that not less than 75 percent of solid waste generated be source reduced, recycled, or composted by the year 2020. The 2011 amendments expand recycling to businesses and apartment buildings; require the state to develop programs to recycle three-quarters of generated waste; and require commercial and public entities that generate more than four cubic yards of commercial solid waste per week, and multifamily residential dwellings of five units or more, to arrange for recycling services beginning July 1, 2012.
Public Resources Code Section 42920 - 42927 (SB1016) Per Capita Disposal Measurement Act	This changed the way State agencies and local governments measure their progress toward meeting the statutory waste diversion mandates. Under this Act, State agencies are still required to maintain the 50 percent waste diversion requirement as mandated by AB 75 (Strom-Martin, Chapter 764, Statutes of 1999). However, State agencies and large State facilities would now use per capita disposal as an indicator of their progress toward meeting the mandate.
Title 24, CCR, Part 11 2010 Green Building Standards Code (CalGreen)	The code is established to reduce construction waste, make buildings more efficient in the use of materials and energy, and reduce environmental impact during and after construction. Effective January 1, 2011, in jurisdictions without a construction and demolition (C&D) ordinance requiring the diversion of 50 percent of construction waste, the owners/builder of newly constructed buildings within the covered occupancies are required to develop a waste management plan and divert 50 percent of the construction waste materials generated during the project.
Title 22 California Code of Regulations§ 66261.4(b) (5) (A) (6) & (7) Exclusions.	(b) Wastes which are not hazardous wastes. The following wastes are not hazardous wastes: (5)(A) Wastes, which meet the criteria for classification as a RCRA hazardous waste set forth in section 66261.100(a)(1), (a)(2), or (a)(3), resulting from the extraction, beneficiation, and processing of ores and minerals (including coal, phosphate rock and overburden from the mining of uranium ore), except as provided by 40 CFR section 266.112 for facilities that burn or process hazardous waste, are not hazardous wastes and are not subject to the requirements of this division or of Chapter 6.5 of Division 20 of the Health and Safety Code. However, these wastes remain subject to Article 9.5 of Chapter 6.5 of the Health and Safety Code if the wastes would otherwise be classified as hazardous wastes pursuant to section 25117 of the Health and Safety Code or pursuant to this division. For purposes of this paragraph, beneficiation of ores and minerals is restricted to the following activities: Crushing; grinding; washing; dissolution; crystallization; filtration; sorting; sizing; drying; sintering; pelletizing; briquetting; calcining to remove water and/or carbon dioxide; roasting; autoclaving, and/or chlorination in preparation for

	leaching (except where the roasting (and/or autoclaving and/or chlorination)/leaching sequence produces a final or intermediate product that does not undergo further beneficiation or processing); gravity concentration; magnetic separation; electrostatic separation; flotation; ion exchange; solvent extraction; electrowinning; precipitation; amalgamation; and heap, dump, vat, tank, and in situ leaching. For the purpose of this paragraph, solid waste from the processing of ores and minerals includes only the following wastes: 6. Gasifier ash from coal gasification; 7. Process wastewater from coal gasification;
Policies	
Kern County, Code of Ordinance, Title 8, Health and Safety, Chapter 8.28 Solid Waste	Kern County would ensure all new development complies with applicable provisions of County Integrated Solid Waste Management Plan.
Kern County and Incorporated Cities Integrated Waste Management Plan	The Kern County and Incorporated Cities Integrated Waste Management Plan addresses issues pertaining to nonhazardous waste disposal and other waste facilities.

SETTING

Proposed Project

As noted in the **Project Description** section of this document, the proposed project would consist of the construction and operation of HECA, a new baseload electric generating plant, which would demonstrate Integrated Gasification Combined Cycle (IGCC) technology. The project would gasify a 75 percent coal and 25 percent petroleum coke fuel blend to produce synthesis gas. The synthesis gas would be purified to a hydrogen-rich fuel. The hydrogen rich fuel would produce 300 megawatts (MW) nominal low-carbon baseload electricity in a Combined Cycle Power Block, low-carbon nitrogen-based products in an integrated Manufacturing Complex, and carbon dioxide for use in enhanced oil recovery with carbon capture and sequestration on a commercial scale. Linear facilities include a 2-mile electrical transmission line, a 13-mile Pacific Gas and Electric Company (PG&E) natural gas pipeline, a 15-mile pipeline for process water (brackish groundwater from the Buena Vista Water Storage District (BVWSD)), a 1-mile potable West Kern Water District line, and a 3-mile carbon dioxide (CO_2) pipeline (HECA 2012e, page 5.13-2). The coal would be delivered to the project site either by train on an industrial railroad spur extending five miles to the site or trucked from an existing coal trans-loading facility 27 miles from the site (HECA 2012e, page 5.13-2).

A fuel blend of 75 percent bituminous coal and 25 percent California petroleum coke (petcoke) would be gasified to produce synthetic gas (syngas) that would be further processed and cleaned in an Integrated Gasification Combined-Cycle gasifer to produce hydrogen-rich fuel. Ninety percent of the carbon would be captured in a high-purity CO_2 stream. Occidental of Elk Hills, Inc (OEHI) is proposing to extend the life of its Enhanced Oil Recovery (EOR) operations in the Elk Hills Unit by utilizing carbon dioxide (CO_2). Carbon dioxide (CO_2) would be purchased from HECA project. The CO_2 would be compressed and delivered via pipeline to OEHI's EOR Processing Facility. The compressed CO_2, which has the same characteristics as a liquid, is injected into an oil reservoir via injection wells designed for CO_2 injection. The CO_2 flows from the injection well and dissolves in the oil. CO_2 mixes with oil, resulting in lower oil viscosity, enhanced oil mobility and lower interfacial tension when compared to oil extraction without CO_2 EOR. A technique of alternating cycles of water injection with cycles of CO_2 injection may be used to enhance the oil recovery.

Construction of the HECA Project is estimated to take 42 months (HECA 2012e, page 2-56). Once constructed, the plant would be capable of operating seven days a week, 24 hours a day, with a planned operational life of 25 years (HECA 2012e, page 5.13-11). Construction activities associated with the HECA Project would produce a variety of mixed nonhazardous wastes, such as soil, wood, metal, concrete, etc. Waste would be recycled, where practical, and non-recyclable waste would be deposited in a California Class III landfill. The hazardous waste generated during this phase of the project would consist of used oils, universal wastes, solvents, and empty hazardous waste materials. Universal wastes are hazardous wastes that contain mercury, lead, cadmium, copper, and other substances hazardous to human and environmental health. Examples of universal wastes are batteries, fluorescent tubes, and some electronic devices. Hazardous waste would be disposed of in a California hazardous waste landfill.

Operation and maintenance of the plant and associated facilities would generate a variety of wastes, including hazardous wastes. The project is expected to produce a large quantity of gasification solids, 246, 016 cubic yards per year. Sanitary wastes would be discharged to a new, on-site septic system and leach field (HECA 2012e, page 5.13-9). Wastewater would be generated from the cooling tower blowdown, raw water treatment, gasifier condensate wastewater, the sour water stripper, the Acid Gas Removal unit , and the Urea plant (HECA 2012b, page 5.13-9) To control air pollutant emissions from the combustion of the hydrogen rich fuel and the natural gas used to run the turbines, the project would employ selective catalytic reduction (SCR) and oxidation catalyst equipment and chemicals, which generate both nonhazardous and hazardous wastes.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

As discussed in the Introduction, this document analyzes the project's impacts pursuant to both the National Environmental Policy Act (NEPA) and CEQA. The two statutes are similar in their requirements concerning analysis of a project's impacts. Therefore, unless otherwise noted, staff's use of, and reference to, CEQA criteria and guidelines also encompasses and satisfies NEPA requirements for this environmental document.

This **Waste Management** analysis addresses a) existing project site conditions and the potential for contamination associated with prior activities on or near the project site and b) the impacts from the generation and management of wastes during project construction and operation.

a) For any site in California proposed for the construction of a power plant, the applicant must provide documentation about the nature of any potential or existing releases of hazardous substances or contamination at the site. If potential or existing releases or contamination at the site are identified, the significance of the release or contamination would be determined by site-specific factors, including, but not limited to: the amount and concentration of contaminants or contamination; the proposed use of the area where the contaminants/contamination are found; and any potential exposure pathways for workers, the public, or sensitive species or environmental areas that may be exposed to the contaminants. Any unmitigated contamination or releases of hazardous substances that pose a risk to human health or environmental receptors would be considered significant by Energy Commission staff.

As a first step in documenting existing site conditions, the Energy Commission's power plant site certification regulations require that a Phase I Environmental Site Assessment (ESA) be prepared[1] and submitted as part of an application for certification. The Phase I ESA is conducted to identify any conditions indicative of releases or threatened releases of hazardous substances at or near the site and to identify any areas known to be contaminated (or a source of contamination) at or near the site.

In general, the Phase I ESA uses a qualified Environmental Professional (EP) to conduct inquiries into past uses and ownership of the property, research history of hazardous substance releases or hazardous waste disposal at the site and within a certain distance of the site, and visually inspect the property, making observations about the potential for contamination and possible areas of concern. After conducting necessary file reviews, interviews, and site observations, the EP then provides findings about the environmental conditions at the site. In addition, since the Phase I ESA does not include sampling or testing, the EP may also give an opinion about the potential need for any additional investigation. Additional investigation may be needed, for example, if there were significant gaps in the information available about the site, an ongoing release is suspected, or to confirm an existing environmental condition.

In conducting its assessment of a proposed project, Energy Commission staff reviews the project's Phase I ESA and works with the appropriate oversight agencies, as necessary, to determine if additional site characterization work is needed. If additional investigation is needed to identify the extent of possible contamination, a Phase II ESA may be required. The Phase II ESA usually includes sampling and testing of potentially contaminated media to verify the level of contamination and the need for remediation at the site. If a hazardous substance release or contamination is identified at the site, staff would again work with the appropriate oversight agencies to identify what mitigation, if any, may be necessary to protect human health and the environment from any releases or contamination identified.

b) Regarding the management of project-related wastes generated during construction and operation of the proposed project, staff reviews the applicant's proposed solid and hazardous waste management methods and determines if the methods proposed are consistent with the LORS identified for waste disposal and recycling. The federal, state, and local LORS represent a comprehensive regulatory system designed to protect human

[1] Title 20, California Code of Regulations, section 1704(c) and Appendix B, section (g)(12)(A). Note that the Phase I ESA must be prepared according to American Society for Testing and Materials protocol or an equivalent method agreed upon by the applicant and the Energy Commission staff.

health and the environment from impacts associated with management of both nonhazardous and hazardous wastes. Absent any unusual circumstances, staff considers project compliance with LORS to be sufficient to ensure that no significant impacts would occur as a result of project waste management. Staff then reviews the capacity available at off-site treatment and disposal sites and determines whether or not the proposed power plant's waste would have a significant impact on the volume of waste a facility is permitted to accept. When project-related waste disposal approaches or exceeds a threshold of ten percent of a county's available landfill capacity, staff would consider it a potentially significant impact and would evaluate other information that may help to determine the significance of the project's waste disposal impacts.

DIRECT/INDIRECT IMPACTS AND MITIGATION

Existing Site Conditions and Possible Contamination

The HECA site is located in the west-central portion of Kern, County, California, Section 10 of Township 30 South, Range 24 East within the San Joaquin Valley. The San Joaquin Valley is California's leading agricultural producing region. The project is seven miles west of the city of Bakersfield and 1.5 miles northwest of the unincorporated community of Tupman. The Elk Hills Oil Field is a hydrocarbon producing area located approximately 1 mile south of the project site. The project site is located approximately 1 mile south of the Stockdale Highway, and approximately 2 miles southwest of Interstate 5. The project site is largely agricultural land and is primarily surrounded by agricultural land. The land adjacent to the northwestern corner of the project site contains the Port Organics Ltd. (PO) Products Natural Fertilizer Manufacturing Plant. Approximately 0.8 acre of the PO plant is located on the HECA project site (HECA 2012e, page 5.13-4). The East Side Canal lies to the east of the northeastern corner of the site. Located southwest of the site are the West Side Canal, the Outlet Canal, and the California Aqueduct (HECA 2012e, Figure 2-4).

Three Phase I Environmental Site Assessments (ESAs) and one Phase II ESA were completed for the proposed project site. The last Phase I ESA was dated April 2012 and was prepared by URS for the 453 acre project site. The ESA was completed in accordance with the American Society for Testing and Materials Standard Practice E 1527-05 for ESAs. The December 2010 Phase II ESA, prepared by AECOM, was completed to evaluate the recognized environmental conditions (RECs) that were identified in the April 2009 and August 2010 HECA Phase I ESAs. A REC is considered to be the presence or likely presence of any hazardous substances or petroleum products on a property under conditions that indicated an existing release, past release, or a material threat of a release into structures on the property or in the ground, groundwater, or surface water of the property. Most of the RECs for this project are depicted in **Waste Management Figure 1.** The RECs for the proposed project site include: five former underground storage tanks (USTs), unidentified concrete structures, a farm equipment wash pad, a former PO fertilizing manufacturing facility, outdoor and indoor tailings piles of raw materials used by PO, PO East Sump, and a number of locations with stained surface soil. (HECA 2012e, Appendix L).

The results of the preliminary soil sampling and analytical testing indicate that there are elevated concentrations of petroleum hydrocarbons and other contaminants affected by previous site activities on a former wash area immediately north of the HECA site. There is soil staining in various areas on the project site. The soil staining is likely to be caused by handling of fuel, lubricating oils, and pesticides. Residual contaminants at the site include organochlorine pesticides, dieldrin, endrin, and endosulfan (HECA 2012e, page 5.13-3).

Soil samples taken at the site indicate that concentrations of the pesticides dieldrin, endrin, and endosulfan exceed the Regional Water Quality Control Board (RWQCB) Environmental Screening Levels, but did not exceed the California Human Health Screening Levels (CHHSLs)[2] (HECA 2012e, page 5.13-3). Staff is concerned that hazardous substances are located on the proposed project site. The Department of Toxic Substances Control (DTSC) has indicated that additional site characterization is required to further define the level of contamination at the proposed site. Staff will not defer mitigation and must ensure that there is no potential for construction workers and onsite industrial workers to be exposed to contaminated surface and subsurface soils, which could result in adverse health effects. The project owner must enter into an Agreement with DTSC for the purpose of fully characterizing and if necessary remediating the site property so that it is in the appropriate condition to allow for future use. In addition based on the type of agreement with DTSC the applicant should conduct the necessary site characterization to determine if site remediation is needed and if so what the scope of remediation would be prior to the FSA.

Provided the applicant can satisfactorily characterize site conditions and develop the scope of remediation needed prior to completion of the FSA staff would also recommend that the project owner develop a Soils Management Plan (SMP) describing the procedures that would be followed during construction and operation at the site. The plan would be designed to protect workers from potential adverse reactions to The objective of the SMP is to describe the procedures that would be followed during the soil disturbances so workers can be protected from adverse reactions to any soil contamination that may be encountered. Staff proposes Condition of Certification **WASTE-1** to ensure the applicant has procedures in place to properly handle and dispose of contaminated soil. The scope of the SMP would be limited to activities involving the excavation, characterization, management, reuse and/or disposal of soils at this site. The SMP would cover the following issues:

- Land use history, including description and locations of known contamination.
- A listing and description of institutional controls, such as the County's excavation ordinance and other local, state, and federal regulations and laws that would apply to HECA.
- Names and positions of individuals involved with soils management and their specific role.
- An earthwork schedule.
- A description of protocols for the investigation and evaluation of historically related chemicals such as total petroleum hydrocarbons (TPH) and previously unidentified contamination that may be encountered, including any temporary and permanent controls that may be required to reduce exposure to onsite workers, visitors and the public.

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[2] CHHSLs were developed as a tool to assist in the evaluation of contaminated sites for potential adverse threats to human health. The soil and soil gas CHHSLs are modeled after the U.S. EPA Region IX PRGs. The primary difference between the CHHSLs and PRGs is the use of CAL/EPA specific "toxicity factor" (estimates of a chemical's toxicity to humans) in development, when available, rather than toxicity factors published by U.S. EPA.

- Requirements for site-specific Health and Safety Plans (HSPs) to be prepared by all contractors at HECA.
- Hazardous waste determination and disposal procedures for known and previously unidentified contamination.
- Requirements for site specific techniques at the site to minimize dust, manage stockpiles, run-on and run-off controls, waste disposal procedures, etc.
- Copies of relevant permits or closures from regulatory agencies

The SMP would include engineering controls, Health and Safety Plans, earthwork schedules and list of responsible staff. Staff is requiring Condition of Certification **WASTE-1** to provide protective measures as needed. These measures include soil removal, refined or enhanced airborne dust mitigation measures currently proposed in the **Air Quality** section of this document so as to better control emissions of fugitive dust containing hazardous wastes (such as increased watering frequency, use of a chemical “wetting agent”, continuously covering stockpiled soils), workers wearing personal protective equipment for short durations, and a combination of all three measures. The implementation of refined and enhanced dust suppression measures and using personal protective equipment can be implemented immediately.

In the event that agricultural chemicals or other contaminants are detected at levels that are considered hazardous, then soil removal or other remediation methods are proposed by staff in Condition of Certification **WASTE-1, WASTE-2,** and **WASTE-3**. Proposed conditions **WASTE-2** and **WASTE-3** would require the project owner to further characterize and remediate the site if other conditions are found during site preparation. These proposed conditions would ensure that any chemicals occurring in hazardous concentrations would be appropriately mitigated in accordance with applicable LORS.

The Elk Hills Oil Field (NPR-1) is an oil-producing field owned by Occidental of Elk Hills, Inc (Oxy). The facility was formerly owned by the United States Department of Energy (DOE) and Chevron Oil Company. DOE sold its interest in the NPR-1 to Occidental Petroleum in 1997. The NPR-1 occupies approximately 47,985 acres or 75 square miles. As a result of the land transfer to Occidental, California Department of Toxic Substances Control (DTSC) entered into an Agreement for Site Assessment (ASA) with DOE and completed a Resource Conservation and Recovery Act (RCRA) Facility Assessment (RFA) of NPR-1 in 1998. DOE agreed to head up an environmental and human health risk assessment of the entire site with remediation to address the effects of past practices at the site.

The working arrangement with DTSC began with an ASA starting in 1997. Three amendments have been made to the ASA, the last of which was for a work plan for the assessment of 131 Areas of Concern (AOCs). The AOCs consist of both small and large areas of contamination. The work was stalled for seven years. On December 23, 2008, DOE and DTSC signed a Corrective Action Consent Agreement to complete the work in December, 2011 and early 2012. DOE representatives submitted numerous Pre-Decisional Project Approach documents. The documents Include an "overview of the planned approach to achieve site closure" for each of the approximate 131 AOCs (DTSC ENVIROSTOR Occidental of Elk Hills (80001254).

To ensure that contamination is not spread at the EHOF and that construction workers are not exposed to hazardous materials as a result of project related activities, safety procedures should be developed and implemented for the construction of the project. All federal, state and local statutes and regulations must be complied with, and DTSC, DOE, and Oxy employees and contractors must be made aware of areas of concern/contamination. Staff recommends DTSC adopt and implement **Mitigation Measure WASTE-1**. **Mitigation Measure Waste-1** would require OEHI to keep DOE and DTSC informed of construction areas and implement all appropriate and applicable safety measures to limit exposure to hazardous materials.

Project Linear Alignment

The crops grown around the HECA 2012 project potable water line, process water line, transmission lines and natural gas lines are located in areas that have crops very similar to linears associated with the 2009 amended HECA project. Typical crops grown in the area include alfalfa, cotton, onion dry, pistachio, sugar beet, and wheat. URS obtained available crop information from Kern County Department of Agriculture and Measurements Standards to identify past crops for the years 1998 to 2008.There are over 95 pesticides used on the various crops around the project linears (URS 2010k Data Response 38). Cliff Smith California Department of Pesticide Regulation, Pesticide Programs Division, Enforcement Branch confirmed that the pesticides currently used in the area and on the list provided by Kern County are non-toxic.

Refined or enhanced airborne dust mitigation measures currently proposed in the **Air Quality** section of this document so as to better control emissions of fugitive dust containing pesticides and/or hazardous wastes (such as increased watering frequency, use of a chemical “wetting agent”, continuously covering stockpiled soils), workers wearing personal protective equipment for short durations, and a combination of these measures will help to protect construction workers. For further analysis of impacts from airborne dust and protection of public health see the **Air Quality** section of this document.

Construction Impacts and Mitigation

Site preparation, construction, and startup of the proposed power plant and associated facilities would take approximately 42 months and would generate 3,177 cubic yards of solid nonhazardous and hazardous waste (HECA 2012e, Table 5.13-21). Staff was not provided a breakdown of types and quantities of nonhazardous waste that will be generated from the OEHI component to confirm that the project will not have an impact on Kern County. This data would be needed for staff to complete assessment of potential impacts.

Nonhazardous Wastes

The applicant has indicated that non-hazardous wastes would be recycled to the extent possible and nonrecyclable wastes would be collected by a licensed hauler and disposed of in a solid waste disposal facility, pursuant to Title 14, CCR, Section 17200 et seq.

The California Department of Resources Recycling and Recovery (now CalRecycle formerly California Integrated Waste Management Board (CIWMB)) is responsible for recycling, waste reduction, and product reuse programs in California. Officially known as the Department of Resources Recycling and Recovery, CalRecycle also promotes innovation in technology to encourage economic and environmental sustainability. Under the administration of CalRecycle the Integrated Waste Management Act requires jurisdictions such as Kern County to divert 50 percent of their waste from landfill disposal. Jurisdictions select and implement the combination of waste prevention, reuse, recycling, and composting programs that best meet the needs of their community while achieving the diversion requirements of the Act. SB 1016 (Stats. 2008, ch. 343) introduced a per capita disposal measurement system that measures the 50 percent diversion requirement using a disposal measurement equivalent. The 2008 California Green Building Standards Code Requires all construction projects to develop a recycling plan to divert and/or recycle at least 50 percent of waste generated during construction, (CalGreen Building Standards Code Section 708 construction Waste Reduction, Disposal and Recycling).

Adoption of Condition of Certification **WASTE-4** would facilitate proper management of project construction wastes. Condition of Certification **WASTE-4** requires the project owner to develop and implement a Construction Waste Management Plan. The plan would identify the type, volume, and waste disposal and recycling methods to be used during construction of the facility. Staff believes that compliance with the proposed condition of certification would also assist the applicant’s compliance with the CalGreen Building Code requirements. Staff believes this condition of certification would ensure construction wastes would be handled and disposed of in accordance with applicable LORS.

Nonhazardous liquid wastes would also be generated during construction, including sanitary wastes, dust suppression and stormwater drainage, and equipment wash and test water. Sanitary wastes would be collected in portable, self-contained chemical toilets and pumped periodically for disposal at an appropriate facility. Potentially contaminated equipment wash and/or test water would be contained at designated areas, tested to determine if hazardous, and either discharged to the storm water retention basin (if nonhazardous) or transported to an appropriate treatment/disposal facility. Please see the **Soil and Water Resources** section of this document for more information on the management of project wastewater.

Hazardous Wastes

Hazardous wastes that would likely be generated during construction of the HECA project include solvents, waste paint, oil absorbents, used oil, oily rags, batteries, cleaning wastes, spent welding materials, and empty hazardous material containers (HECA 2012e, Table 5.13-2).

The total volume of liquid hazardous wastes generated during construction is estimated to be approximately four million gallons (including sanitary waste). All liquid hazardous waste would be considered for recycling. Liquids not suitable for recycling would be taken to a suitable Treatment, Storage or Disposal Facility for disposal.
Both the construction contractor and the project owner/operator could be considered the generators of hazardous wastes at the site during the construction period. Because hazardous waste generator status is determined by site, the project owner would be required to obtain a unique hazardous waste generator identification number for the site prior to starting construction, pursuant to proposed Condition of Certification **WASTE-5**. Wastes would be accumulated on site for less than 90 days and then properly manifested, and transported to and disposed of at a permitted hazardous waste management facility by licensed hazardous waste collection and disposal companies.

Staff has reviewed the proposed waste management methods described in the Application for Certification (HECA 2012e, Table 5.13-2), and in the responses to data requests, and concludes that project construction wastes would be managed in accordance with all applicable LORS. Absent any unusual circumstances, staff considers project compliance with LORS during construction to be sufficient to ensure that no significant impacts would occur as a result of construction-related project waste management activities. To facilitate continuous project compliance with LORS during construction, staff proposes Condition of Certification **WASTE-6**, requiring the project owner to notify the CPM if and when the owner becomes aware of any HECA project waste management-related enforcement action being initiated or taken by a regulatory agency. Along with the notification, the project owner must also describe how the violation would be corrected and include a timeline for completion of the correction. In the event that construction excavation, grading, or trenching activities for the proposed project encounter potentially contaminated soils, specific waste handling, disposal, or other precautions may be necessary pursuant to hazardous waste management LORS. Staff also believes that proposed conditions of certification **WASTE-2** and **WASTE-3** would be adequate to address any soil contamination contingency that may be encountered during construction of the project and would further support compliance with LORS.

Operation Impacts and Mitigation

The proposed HECA project would generate 14,983 cubic yards per year (not including gasification solids) of nonhazardous and hazardous solid waste under normal operating conditions. Table 5.13-3 of the project AFC gives a summary of the anticipated operation waste streams, estimated waste volumes and generation frequency, and management methods proposed.

Nonhazardous Solid Wastes

Nonhazardous solid wastes generated during HECA project operation, excluding gasification waste, could include routine maintenance wastes (such as used air filters, scrap metal, and plastics) and concentrated process waste (salt cake from the Zero Liquid Discharge system (ZLD) and spent carbon monoxide (CO) oxidation catalysts from the air pollutant emissions control equipment), as well as domestic/sanitary and office wastes (such as office paper, newsprint, aluminum cans, glass, and septic system sludge) (HECA 2012e, Table 5.13-3).

Page 4.16-8 of Volume II of the amended AFC states that 4,000 tons per year of solid waste is disposed into solid waste landfills from EHOF during operation. The project owner does not anticipate a significant increase of solid (nonhazardous) waste generated from the OEHI component. Staff was not provided a breakdown of types and quantities of nonhazardous waste that will be generated from the OEHI component to confirm that the project will not have an impact. This information is needed for staff to complete assessment of potential impacts.

Each city, county, or regional agency with a CalRecycle-approved planning document (such as a Source Reduction and Recycling Element (SRRE) or a countywide regional agency Integrated Waste Management Plan) must submit an annual report to CalRecycle summarizing its progress in reducing solid waste as required by Public Resource Code (PCR) Section 41821. Kern County provides CalRecycle with an SRRE and an Integrated Waste Management Plan (IWMP). The SRRE sets forth a jurisdiction's basic strategy for management of solid waste generated within its borders, with emphasis on implementation of the SRRE.

Before operations can begin, the project owner should be required to develop and implement an Operation Waste Management Plan pursuant to proposed Condition of Certification **WASTE-7**. This would facilitate proper management of project operation wastes by requiring the applicant to identify the type and volume of waste, and waste disposal and recycling methods to be used, during operation of the facility. If nonhazardous waste is exported out of the state of California the applicant should be required to provide reports pursuant to Title 14, California Code of Regulations, Section 18808.9. A public contract hauler who exports solid waste from California shall provide the agency in which the waste originated with the total tons of solid waste exported from each jurisdiction of origin. Reporting in accordance with the proposed operation waste management plan would also provide the necessary information for Kern County to demonstrate compliance with IWMP as discussed above.

Liquid Wastes

Liquid wastes generated during operations include wastewater from the cooling tower blowdown, raw water treatment, gasifier condensate wastewater, sour water stripper, the Acid Gas Removal unit, and the Urea plant. Treatment and disposal of waste water is addressed in the **Soil and Water Resources** section of this document.

Hazardous Wastes

The project owner/operator would be considered the generator of hazardous wastes at the site during HECA operations. Therefore, the project owner’s unique hazardous waste generator identification number, obtained prior to construction in accordance with proposed Condition of Certification **WASTE-5**, would be retained and used for hazardous waste generated during facility operation.

Hazardous solid wastes that may be generated during routine project operation include oil filters and oily rags, spent Selective Catalytic Reduction (SCR) and oxidation catalysts, waste paint and empty containers, as well as universal wastes (batteries, fluorescent light tubes, and similar items) (HECA 2012e, Table 5.13-3). Should any HECA operations waste management-related enforcement action be taken or initiated by a regulatory agency, the project owner would be required by proposed Condition of Certification **WASTE-6** to notify the CPM whenever the owner becomes aware of any such action.

Staff has not been provided a breakdown of types and quantities of hazardous waste that will be generated from the OEHI project to confirm that the project will not have an impact. This information is needed for staff to complete assessment of potential impacts.

In addition, spills and unauthorized releases of hazardous materials or hazardous wastes may generate contaminated soils or cleanup materials that may require management and disposal as hazardous waste. Proper hazardous material handling and good housekeeping practices would help keep spill wastes to a minimum. However, to ensure proper cleanup and management of any contaminated soils or waste materials generated from hazardous materials spills, staff proposes Condition of Certification **WASTE-10**, which requires the project owner/operator to document, clean up, and properly manage and dispose of wastes from any hazardous materials spills or releases in accordance with all applicable federal, state, and local requirements.

The hazardous wastes would be temporarily stored on site, transported off site by licensed hazardous waste haulers, and recycled or disposed of at authorized disposal facilities in accordance with established standards applicable to generators of hazardous waste (Title 22, CCR, §66262.10 et seq.). Should any operations waste management-related enforcement action related to disposal of the gasification solids be taken or initiated by a regulatory agency, the project owner would be required by proposed Condition of Certification **WASTE-6** to notify the CPM whenever the owner becomes aware of any such action and provide information on how the violation(s) causing the enforcement action would be corrected.

Gasification Solids

The project would gasify petroleum coke (petcoke) or blends of petcoke and coal, as needed, to produce hydrogen-rich fuel for a combustion turbine operating in a combined cycle mode to produce electricity and sequester carbon dioxide in the EHOF. The blend of feedstock was based on the maximum performance guarantee the manufacturer provided HECA which is 25 percent petcoke and 75 percent coal (URS 2013 tn: 69172). Petcoke is a carbonaceous solid derived from the refining of heavy crude oils. The project would generate approximately 306,000 tons (271,584 cubic yards)[3] of gasification solids per year (HECA 2012e, Table 5.13-3). As proposed by the applicant, the gasification solids would either be sold or reused, or be disposed of as nonhazardous waste ((HEI 2009c, page 2-24).

The project owner suggests in the AFC that the gasification solids produced from the feedstock are excluded from hazardous waste regulations and requirements, per the exclusions in applicable federal and California regulations and requirements, (i.e., Title 40 of the Code of Federal Regulations (40 CFR) Section 261.4(b) (7) (ii) (F), and California regulations 22 CCR Section 66261.4(b) (5) (A). Kern County has indicated that although this exclusion applies they would still require the applicant to test and properly characterize the HECA project gasification solids prior to disposal in a Class III (solid/nonhazardous waste) landfill. The gasification solids generated at the HECA facility would be collected and accumulated on a concrete pad until transported. The facility would be covered with a roof and partial siding. The gasification solids handling system is described in **Data Responses A108, A109, A110, A111, A112, A113, and A114** (HECA 2012p).

The HECA project owner cannot conclusively demonstrate the nonhazardous nature of the HECA gasification solids. The project owner does expect the gasification solids to be nonhazardous based on available information from existing Integrated Gasification Combined Cycle (IGCC) facilities. The Applicant conducted a literature search to compile data on the composition and leachability of existing gasification solids. This information was then compared against Toxic Characteristic Leaching Procedure TCLP (federal) standards/thresholds. (Refer to **Waste Management Table 2**) The applicant provided data on four plants. Only one plant was located in California and that plant no longer exists. The applicant has proposed to provide information on the gasification solids characteristics after research has been conducted on similar facilities located in Japan. Staff requests that this information be provided prior to issuance of the FSA/FEIS.

[3] The tons of gasification waste numbers reflect the use of limestone fluxant.

The federal TCLP and California Waste Extraction Test (WET) are test methods used by the U.S. EPA and the California Department of Toxic Substances Control (DTSC) to determine whether a waste is a toxic hazardous waste (40 CFR Part 261). The purpose of the leaching tests is to obtain aqueous phase concentrations of constituents which are released from solids when placed in a land disposal unit. The tests are similar in that they both simulate what happens to waste in a landfill setting with simulated landfill leachates, and list chemical concentration thresholds (http://ccelearn.csus.edu/wasteclass/mod6/mod_05.html). The applicant states on page 5.13-12 of the HECA amended AFC that similar gasification wastes from the IGCC facilities outside of California have been determined to be nonhazardous based on federal leachate tests. The applicant has not determined the toxicity of the gasification waste using the California WET test. The main differences between TCLP and WET are in both the laboratory analysis methods used and the regulated chemicals that are tested. The California WET protocol is considered more aggressive than the federal method.[4] Therefore, given the more stringent California WET testing methods the concentrations of the constituents tested in **Waste Management Table 2** likely would have been higher and maybe exceed some California regulatory thresholds.

Waste Management Table 2
Comparison of IGCC Gasification Solids Federal TCLP Leaching Analyses

	RCRA TCLP Regulatory Threshold	**Polk Power Station, Ground[1]**	**Polk Power Station, Underground[1]**	**Cool Water[2]**	**Wabash River, 1997[3]**	**Wabash River, 1998[3]**
Constituent	**(mg/L) in Extract**					
Arsenic	5	< 0.01	< 0.01	< 0.06	NR	NR
Barium	100	0.08	0.02	0.32	NR	NR
Cadmium	1	0.01	0.01	< 0.002	NR	NR
Chromium	5	1.43	0.07	< 0.005	NR	NR
Lead	5	0.01	0.01	< 0.08	NR	NR
Mercury	0.2	< 0.0001	< 0.0001	< 0.0004	NR	NR
Selenium	1	0.006	0.002	< 0.08	NR	NR
Silver	5	< 0.01	0.01	< 0.002	NR	NR
Sum of All Constituents for Wabash River					**< 0.682**	**< 0.12**

Source: URS 2010? - URS/D. Shileikis (tn: 59011). Applicant's Response to Energy Commission Data Requests Set three, Data Response 217, Table 217-1, dated 11/10. Submitted to CEC/Docket Unit on 11/10.
[1] Polk gasification solids were generated from feedstock that was a blend of coal and petroleum coke. Source: Groppo and Rathbone, 2008.
[2] Source: Department of Energy, 2002.
[3] Wabash River data were reported only as the sum of the constituents. Source: Wabash River Energy, Ltd., 2000.
< = Less Than (not detected)
Mg/L = milligrams per liter
NR = Not Reported

[4] A comparison between the Federal and California leachate testing protocol is summarized from information presented on the California Department of Toxic Substances Control web site (DTSC, 2010) as follows:
• The federal TCLP method (U.S. Environmental Protection Agency Method 1311) involves an 18-hour extraction (plus or minus 2 hours) with an acetate buffer solution. The ratio of extraction solution to sample is 20-to-1. The test simulates contaminant leaching of waste materials that are disposed with municipal solid waste in a landfill.
• The California WET protocol involves a 48-hour extraction with a citrate buffer solution (except for chromium-VI, for which the extraction solution is deionized water). The ratio of extraction solution to sample is 10-to-1 (URS Data Response 218, http://ccelearn.csus.edu/wasteclass/mod6/mod_05.html).

The final disposition of the gasification waste as either a Class I (hazardous) or Class III (non-hazardous) waste should be determined using the source of coal and petcoke and processing methods proposed for HECA operation prior to project construction so a strategy for management of the waste can be developed. Depending on the characterization of the waste there could be different potentially significant impacts related to the volume of waste and how it can be disposed. These impacts are further discussed below under impacts on existing waste disposal facilities. The testing can also be used to identify whether it is possible to reuse as a nonhazardous waste in commercial applications (e.g. cement products, soil amendment, etc.). Staff has also received a comment letter from Kern County (Kern County 2013d) expressing their concern about the characterization of the waste. They have requested that prior to acceptance of residual material from HECA at any public landfill, the project applicant is required to supply the Kern County Waste Management Department (KCWMD) a characterization of the waste for chemical and physical characteristics, and secure written approval from the Director of the KCWMD to ensure compatibility with landfill operations and fee schedules. Mitsubishi will operate a gasification pilot in Japan. Staff believes the results of these tests should be submitted prior to completion of the FSA so there is preliminary indication of whether the waste will be hazardous or non-hazardous. This will in turn affect what disposal options are available and whether there may be a market for the waste. This information is needed to evaluate what mitigation would be appropriate for the potential impacts.

If adequate preliminary characterization of the gasification solids can be conducted prior to the FSA staff would recommend the applicant be required to comply with Condition of Certification **WASTE-8,** which requires that the project owner perform ongoing tests to classify the waste and determine the appropriate method of disposal whenever there are any variations in source of fuel supply or changes in the percentages of fuel sources used during operation. This condition would also require that the applicant ensure there continues to be: 1) No impact to local landfills, 2) an ongoing market for the waste, 3) and they can continue to comply with Kern County and California state waste disposal requirements.

In rare cases, the zero liquid discharge (ZLD) sludge/solids could contain concentrations of chemicals that could be hazardous, depending on water quality and cooling system operation. To ensure proper disposal of the ZLD solids, staff proposes Condition of Certification **WASTE-9,** which requires that the project owner perform the appropriate tests to classify the waste and determine the appropriate method of disposal. All nonhazardous wastes would be recycled to the greatest extent possible and nonrecyclable wastes would be collected by a licensed hauler and disposed in a Class II solid waste disposal facility, in accordance with Title 14, California Code of Regulations.

Impact on Existing Waste Disposal Facilities

Nonhazardous Solid Wastes

The HECA project during operation would generate an extremely high volume of waste because of the gasification process. If the waste is generated or disposed in Kern County, the County's State-mandated diversion rates would be exceeded and the County would incur financial penalties from the State (CalRecycle) and increased costs for improvements made to local landfills. The project could dispose of 306,000 tons (271,584 cubic yards) per year of gasification solids and approximately an additional 15,000 tons (14,983 cubic yards) per year of miscellaneous operational waste in a Class III landfill (HECA 2012e, Table 5.13-3). The project owner proposes to reuse, reclaim or dispose of the gasification wastes in a landfill. The applicant is anticipating that the gasification waste would be classified as non-hazardous. **Waste Management Table 3** identifies four nonhazardous (Class III) and one Class II (designated)[5] waste disposal facilities located in Kern County that could potentially take the nonhazardous construction and operation wastes generated by the project. The remaining capacity for the four Class III landfill facilities combined is over 60 million cubic yards. The maximum amount of nonhazardous waste generated from project construction and operation (including gasification solids), 271,584 cubic yards (306,000 tons) assuming none is reused or recycled, would consume almost ten percent of the remaining landfill capacity of the Kern County Class III landfills during the life of the project.

Waste Management Table 3
Kern County Class III Landfills

Solid Recycling/Waste Disposal Site	Title 23 Class	Permitted Throughput (Daily Tonnage)	Permitted Capacity	Remaining Capacity	Estimated Closure Date
Taft Sanitary Landfill (Solid Waste Facility)[1]	Class III	419 tons per day	8.8 million cubic yards	6.7 million cubic yards	2123
Bakersfield Metropolitan Sanitary Landfill[1] Facility	Class III	4.5 thousand tons per day	53 million cubic yards	35 million cubic yards	2038
Shafter-Wasco Sanitary Landfil[1]	Class III	888 tons per day	11,6 million cubic yards	7.9 million cubic yards	2027
U.S. Borax, Inc Refuse Waste Pile[1]	Class III	443 tons per	8.5 million cubic yards	1.0 million cubic yards	2023
McKitrick Waste Treatment Site	Class II	1.2 thousand tons per day	2.1 million cubic yards	84.1 thousand cubic yards	2029
Chemical Waste Management Kettleman Hills Landfill	Class I	400 trucks per day	10.7 million cubic yards	<100 thousand cubic yards	2022

Sources: HECA AFC Table 5.13-1 and http://www.calrecycle.ca.gov/SWFacilities/Directory/Search.aspx
[1] Kern county owned public solid waste facilities. http://www.kerncountywaste.com/landfills-transfer-stations-bin-sites/landfills

[5] Class II landfills allow disposal of designated wastes determined by the Regional Water Quality Control Board (RWQCB) to be nonhazardous wastes, but which may contain soluble pollutants that could be released in concentrations exceeding applicable water quality objectives and could cause degradation of waters of the state. (Scott Walker and Robert Anderson)

Staff concludes that if the gasification waste is indeed determined to be nonhazardous as anticipated by the applicant, there could be a significant impact on Kern County or other nearby landfills. Prior to the FSA the applicant should submit the Japanese pilot project's gasification waste test results to staff, using the California Waste Extraction Test (WET) protocol. The WET test is more stringent than the federal TCLP and will be the test used once HECA is in operation. The applicant would also provide a draft Gasification Waste Diversion Plan (GWDP) in accordance with Condition of Certification **WASTE-8** that will outline the project's recycling, disposal and exportation strategies provided the preliminary waste characterization can be completed and demonstrate adequate mitigation strategies for disposal and marketing of the waste can be developed. If this is the case then staff would recommend the applicant be required to comply with condition of certification **WASTE-8** which requires that the project owner perform ongoing tests to classify the waste and determine the appropriate method of disposal whenever there are any variations in source of fuel supply or changes in the percentages of fuel sources used during operation. This condition would also require that the applicant ensure there continues to be: 1) No impact to local landfills, 2) an ongoing market for the waste, 3) and they can continue to comply with Kern County and California state waste disposal requirements
The KCWMD operates and owns several public solid waste facilities (See **Waste Management Table 3**). KCWMD is requesting that the HECA waste stream, including gasification waste if non-hazardous, be subdivided between several facilities to reduce the potential impacts to any one Kern County facility (Kern County 2013d). It may also be necessary for some of the waste to be transported out of the county or state.

The California Integrated Waste Management Act (Public Resources Code section 40000 et seq.) originally required all California cities, counties and approved regional solid waste management agencies responsible for enacting plans and implementing programs to divert 25 percent of their waste by 1995, 50 percent by 2000, and 75 percent by 2020 (http://www.calrecycle.ca.gov/). SB 1016 (Stats. 2008, ch. 343) introduced a per capita disposal measurement system that measures the 50 percent diversion requirement using a disposal measurement equivalent. SB 1016 uses a jurisdiction's population (or in some cases employment) and its disposal as reported by disposal facilities. Kern County's unincorporated jurisdiction's per capita disposal equivalent to a 50 percent diversion rate was set at 7.6 pounds (lbs)/person/day. Kern County's actual disposal rate for the unincorporated area is 5.7 lbs/person/day. The amount of waste generated and disposed of by the HECA project would increase the County's disposal rate by 48.5 percent, thus placing Kern County in potential non-compliance with mandated recycling goals (see **Waste Management Table 4**).

Waste Management Table 4
Disposal Rate (SB 1016)

Kern County (disposal cap)	7.6 lbs/person/day
Kern County (actual)	5.7 lbs/person/day
HECA Project (estimated generation)	5.36 lbs/person/day
HECA plus Kern County	11.56 lbs/person/day
Reference Kern County letter to Board of Supervisor, February 26, 2013	

To avoid regulatory non-compliance KCWMD and staff recommend the applicant undertake one or more of the following strategies:

- Recycle or reuse residual wastes as a beneficial use.

- Dispose of material and receive confirmation from CalRecycle that the waste material cannot be recycled and have Cal Recycle concurrence that the waste can be adjusted out of the jurisdictional reporting as disposal.
- Seek/receive legislative or regulatory exemption (Kern County 2013d).

Staff recommends condition of certification **WASTE-8**, which would require the applicant to identify how the waste can be disposed of and whether there are diversion methods that can be used to identify what the appropriate strategy would be for Kern County to maintain compliance with Public Resources Code section 40000 et seq.

Recycle/Reuse

Staff recommends recycling or reuse of the gasification solids to the greatest extent possible. Data Response A123 suggests that the applicant would complete and submit a white paper to the county on the reuse of the gasification solids (URS 2013, tn: 69339)[6]. HECA November 2009 Data Responses 28 and 115 discussed possible industries that would use the gasification solids, the list included: ready-mix concrete, cement manufacturing, aggregate application, Portland Cement Concrete or a sand-blasting application (November 2009). The data responses did not provide any indication or letters of commitment showing there is a market for the solids and how much would be used for any of the identified purposes.

The California Department of Transportation (Caltrans) could possibly provide potential mitigation for the 246,016 cubic yards of gasification solids. The Caltrans Cement Sub-Group of the California Climate Action Team (CAT) state on their website that Supplementary Cementitious Materials (SCMs) can reduce greenhouse gas (GHG) emissions. Common SCMs in use include slag, fly ash, silica fume, and calcined clay. Using two or more SCMs together with Portland cement is referred to as a ternary cement mix. Proper use of ternary mixes comprised of fly ash and slag can produce better quality concrete. Many of these mixes are being used for construction of the Bay Bridge project, but the fly ash and slag are being imported because of lack of domestic sources. Caltrans encourages the use of SCMs in Portland Cement Concrete (PCC). Staff addresses SCM in Data Requests A215, A216 and A217. The applicant has indicated the solids may not be useable for SCM because of the chemical composition. Staff believes it is premature to make this determination since there is no data on the specific chemical composition of the SCM. Staff believes a final determination of the use of the solids for SCM should be made once the applicant has completed testing. The physical and chemical characteristics of the gasification solids could determine whether the solid may be used as a SCM. The applicant should provide information on the chemical and physical properties of the gasification solids from the Mitsubishi pilot plant prior to the FSA to confirm if the solids are hazardous or non-hazardous. Staff points out that the final composition of the waste cannot be determined until the project is operational due to the potential variability of the fuel sources and petcoke to coal ratio during the operation of HECA. Staff needs the data from the test facility to further evaluate whether it is adequate to depend on for use as a starting point for analysis of potential impacts during future operating scenarios. Staff has also proposed Condition of Certification WASTE-8 which would also

[6] There are a number of waste management data requests related to waste diversion, Data Responses, A114, A115, and A116) to the reuse of the gasification solids. URS 2009j –URS/D. Shileikis (TN: 54054) Applicant's responses to CEC Data Requests Set 1, dated 11/11/09. Submitted to CEC/Docket Unit on 11/12/09.

require the applicant to conduct ongoing testing provided it can be shown impacts can be mitigated using result s of the initial testing.

Exportation of waste

The project owner also submitted the option of waste from the project being disposed out of state. Nonhazardous gasification solids that are not beneficially used would be transported by truck or rail to a Subtitle D solid waste disposal facility. The project owner anticipates using the following facilities when landfill disposal of the solids is required (HECA 2012p, Data Response A122):

- Clean Harbors Sawyer Landfill, USEPA ID: NDD000351270 in North Dakota.
- ECDC Environmental, L.C. Class V Landfill Permit 9433R1 in Utah.

There would be no impacts to the landfills located in North Dakota and Utah. Staff spoke with Steve Tillotson, Assistant Director, North Dakota Department of Health, Division of Waste Management and he stated that 277,000 tons per year of waste imported into North Dakota would not cause an impact the State or the Clean Harbors Sawyer landfill (Tillotson 2013). The ECDC Environmental solid waste landfill located in East Carbon Utah is located on 2,500 acres of land and has 382 million cubic yards of capacity. The landfill permit is renewed every ten years (Bohn 2013). The States of Utah and North Dakota confirmed that both would use 40 CFR§261.4(b): Exclusions: Solid Wastes which are Not Hazardous Wastes (7) ((ii) (F) Coal gasification to dispose of the gasification solids into solid waste (nonhazardous) landfills.

Although, the project owner proposes out-of-state disposal as an option the exported tonnage is applied to Kern County's waste disposal totals. Below is a quote from Melissa Vargas of CalRecycle (Vargas, 2013b):

> "…Even if it is a private business that is paying someone to haul its waste or if it is the private business itself self-hauling and in either circumstance they are hauling it from the point of generation and not from a solid waste facility, then they are involved in solid waste enterprise and solid waste handling. The rules still apply that they must report the exported tonnage and identify the jurisdiction of origin.
>
> Below are excerpts that address the definition of Disposal and the relationship with export tonnages.
>
> Definitions
> •"Disposal" means all solid waste from all sources within California jurisdiction boundaries, transported by all types of haulers (including self-haul) to Board-permitted disposal or transformation facilities.
> • "Disposal" also means: (1) all out-of-state solid waste from all sources, imported to Board-permitted disposal or transformation facilities, and (2) all solid waste originating from all sources within California jurisdiction boundaries and exported out of state.
>
> There could be several implications if we did not capture wastes exported, which include, but are not limited too:
>
> 1. CalRecycle could not effectively determine a Target or Annual pounds per person per day as it is based on disposal;

2. CalRecycle could not effectively determine if the wastes disposed contain recyclables material that could be diverted vs. disposed and ensure viability of markets;
3. CalRecycle staff would have a difficult time assessing programs;
4. Wastes exported vs. utilizing local landfills could impact financial viability of a City or County's programs and financial responsibility for landfill closure plans; and so on.

The following webpage provides information that addresses out-of-state waste disposal and includes the regulatory references: http://www.calrecycle.ca.gov/lgcentral/basics/DispRept.htm

Also, here is a link to the Regulations http://www.calrecycle.ca.gov/Laws/Regulations/Title14/ch9a92b.htm"

Staff believes the exportation of waste may be a viable means of waste diversion or disposal but the role it would play in maintaining compliance with Kern County waste diversion and volume requirements is currently uncertain. Staff recommends the applicant provide additional characterization information based on Mitsubishi gasifier currently operating in order to provide a better understanding of the potential options available for this project. Staff will discuss this issue further in the FSA/FEIS.

Hazardous Wastes

Less than 54 cubic yards of hazardous waste would be generated during the 42 month construction of the HECA facility and disposed of in a Class I Landfill. Hazardous wastes generated during operation would be 277 cubic yards per year. The applicant proposes to recycle these wastes to the extent possible and practical. Section 5.13 of the project AFC provides information on treatment, storage, or disposal facilities (TSDFs); landfills; recycling facilities; and transfer stations that could be used to manage project wastes. Any wastes that cannot be recycled would be transported off site to a permitted TSDF or landfill.

The Clean Harbors Buttonwillow Landfill in Kern County and the Chemical Waste Management Kettleman Hills Landfill in Kings County have approximately 10 million cubic yards of remaining hazardous waste disposal capacity at these landfills, with at least 30 years remaining in their operating lifetimes (HECA 2012e, Table 5.13-2).

Given the availability of recycling facilities for high volume hazardous wastes such as used oil and solvents, along with the remaining capacity available at Class I disposal facilities, staff concludes that the volume of hazardous waste requiring off-site disposal from the HECA project, as proposed by the applicant, would be far less than staff's threshold of significance if the gasification solids are determined to be non-hazardous. Under those circumstances, the proposed project would not significantly impact the capacity or remaining life of the available Class I waste facilities. However, although the applicant states in the AFC that similar gasification wastes from IGCC facilities outside of California have been determined to be nonhazardous based on federal leachate tests, it has not been demonstrated that the gasification waste from the proposed project would be found to be nonhazardous based on California's leachate testing protocol.

If the gasification solids are determined to be hazardous and all or most of the waste generated would need to be disposed of in Class I landfill facilities, the project could potentially pose a very significant impact to California Class I landfill capacity: The maximum annual gasification waste from the project would be 246,016 cubic yards and the annual production of other hazardous waste from the project would be approximately 277 cubic yards, for a potential total annual production of 246,516 cubic yards of hazardous wastes. Multiplying this annual amount by the twenty five year life of the project, the total impact to Class I facilities would be 6,162,900 cubic yards which is approximately 61percent of the existing 10 million cubic yard land fill capacity, far exceeding staff's criterion of 10 percent.

The final disposition of the gasification waste as either a Class I (hazardous) or Class III (non-hazardous) waste, and its possible reuse as a nonhazardous waste in commercial applications (e.g. cement products, soil amendment, etc.), should be determined by sampling and characterization, and by evaluating market potential. As discussed above, to ensure proper reuse or disposal of the gasification solids, staff needs the results of waste characterization tests from the Mitsubishi facility in Japan to evaluate whether the solids waste will be considered hazardous and if there are disposal methods that would ensure there are no impacts to local landfill capacity.

Diversion Program

The County has recommended the HECA project owner be required to compensate Kern County by paying a fee in addition to the gate/tipping fee for disposal. The money would be deposited in a Diversion Mitigation Reserve Account. The money from the Diversion Mitigation Reserve Account would fund Kern County diversion programs. The proposed fees are outlined in **Waste Management Table 5**:

Waste Management Table 5
Diversion Program Mitigation

Cost (dollars)	Tons per day
30	0 – 100 tons per day
50	101 – 200 per day
75	Greater than 200 tons per day

HECA has not responded to this request and it is unknown if the applicant would be willing to participate in the proposed program. Staff believes this program and its suitability as mitigation should be further discussed at a workshop prior to publication of the Final Staff Assessment and could be further defined in the GWDP recommended in Condition of Certification **WASTE-8**. Staff also notes that this program is intended for mitigation only if the waste is found to be nonhazardous.

CUMULATIVE IMPACTS AND MITIGATION

The California Environmental Quality Act (CEQA) Guidelines (Cal. Code Regs., Title 14 Section 15355) define cumulative effects as "two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts."

The Elk Hill Oil Field Legacy Waste Relocation is a project that would be considered with the OEHI CO_2 EOR and HECA wastes to determine possible cumulative impacts. The Department of Energy (DOE) has entered into a Corrective Action Consent Agreement with the Department of Toxic Substances Control (DTSC) for corrective measures for protection of the environmental and public health regarding the clean-up and/or remediation of several “legacy waste sites” within the former NPR-1 or the Elk Hills Oil Field (DTSC 2013). Prior to 1987, wastes were disposed of at several of the “legacy waste sites” throughout the EHOF. As a part of the Consent Agreement, the DOE proposes the relocation of previously disposed wastes from these sites to permitted Kern County facilities. This relocation is expected to begin in 2013 and continue through 2015 (Kern 2013). **Waste Management Table 6** lists the quantities and estimated dates of removal of waste from the EHOF legacy sites.

Waste Management Table 6
Elk Hill Oil Field Legacy Waste Relocation

Area of Concern	Date of Use	Waste Class	Weight (tons)	Estimated date of removal
60	1977-1987	Class II/III	4,500 -6,000	2013
65	1977-1987	Class II/III	18,500 to 25,000	2014/2015
95	1977 through 1987	Class II/III	45,000 to 50,000	2014/2015
104	Prior 1984	Class II/III	150	2013
108	Prior 1984	Class II/III	2,550	2013
109	Prior 1984	Class II/III	4,050	2013
98	1915-1940	Class II/III	150	2013

KCWMD staff is conferring with CalRecycle to verify that the NPR-1(Elk Hills Oil Field) relocated wastes should qualify for a modification from Jurisdictional Disposal Reporting Accounting. Furthermore, Statute (PRC sections 41031-41033, 41331-41333), Regulation (14 CCR sections 18722 et seq. and 18800 et seq.), and CalRecycle Policy allow for reporting yearly disposal tonnage modifications. The KCWMD staff proposes that the wastes relocated as a result of the DOE Consent Agreement should not be subject to the annual Disposal Reporting Accounting methods because these wastes were originally disposed of prior to 1987, and are being relocated for proper and safe disposal (Kern 2013). The relocation of the NPR-1 legacy waste, approximately 586,000 cubic yards, would use less than two percent of Kern County remaining landfill capacity. Also, if CalRecyle would allow a modification to the Kern County Jurisdictions Disposal Accounting, the County would not be affected by relocation of the legacy waste.

As proposed, the amount of nonhazardous and hazardous wastes generated during construction and operation of HECA and OEHI CO_2 EOR would add to the total quantity of waste generated in the region and State of California. The waste management impacts of the proposed project, in combination with past, present and reasonably foreseeable projects in the area would be cumulatively considerable The project has the potential to consume as much as ten percent of Kern County’s Class III landfill capacity. The large quantity of waste would significantly impact Kern County landfills and possibly compromise the county’s compliance with Public Resources Code section 40000 et seq and implementing regulations.

Condition of certification **WASTE-7** and **WASTE-8** would require the applicant to develop and implement an operation waste management plan and GWDP that would address waste diversion goals and identify appropriate waste disposal methods for HECA. These conditions would require the applicant to take all the necessary steps to ensure they mitigate any potential significant impacts.

Staff points out that some of the methods of waste disposal and how they are counted towards Kern County's waste diversion goals and per capita limit may require findings from Cal Recycle. Kern County could petition Cal Recycle to acknowledge that the waste material cannot be recycled and concur that the waste can be adjusted out of the jurisdictional reporting as disposal. Or Kern County may be required to seek and receive legislative or regulatory exemption for the jurisdictions disposal accounting.

Staff also recommends Kern County adopt and implement Mitigation Measure **WASTE - 2** for the OEHI EOR component which would require OEHI to consult with Kern County to develop a waste management and diversion plan that would ensure the county can maintain state compliance and mitigate potentially significant cumulative impacts from disposal of EHOF wastes and legacy waste sites.

COMPLIANCE WITH LORS

Energy Commission staff concludes that the proposed HECA project would comply with all applicable LORS regulating the management of hazardous and nonhazardous wastes during both facility construction and operation. The applicant would be required to recycle and/or dispose of hazardous and nonhazardous wastes at facilities licensed or otherwise approved to accept the wastes. Because hazardous wastes would be produced during both project construction and operation, HECA would be required to obtain a hazardous waste generator identification number from U.S. EPA. HECA would also be required to properly store, package, and label all hazardous waste; use only approved transporters; prepare hazardous waste manifests; keep detailed records; and appropriately train employees, in accordance with state and federal hazardous waste management requirements.

DOE'S FINDINGS REGARDING DIRECT AND INDIRECT IMPACTS OF THE NO-ACTION ALTERNATIVE

DIRECT AND INDIRECT IMPACTS OF THE NO-ACTION ALTERNATIVE

Under the No-Action Alternative, DOE would not provide financial assistance to the Applicant for the HECA Project. The Applicant could still elect to construct and operate its project in the absence of financial assistance from DOE, but DOE believes this is unlikely. For the purposes of analysis in the PSA/DEIS, DOE assumes the project would not be constructed under the No-Action Alternative. Accordingly, the No-Action Alternative would have no impacts associated with this resource area.

RESPONSE TO PUBLIC AND AGENCY COMMENTS

Staff received comments from Kern County and the Department of Toxic Substances Control (DTSC). DTSC reviewed the HECA AFC, the Phase I ESA, and the Phase II ESA and determined that the proposed project site requires additional characterization and the project would require a Voluntary Cleanup Agreement (VCA) with DTSC for possible remediation of the proposed project site (DTSC 2013b).

The KCWMD determined that Kern County's State-mandated diversion rates would be substantially impacted due to the high volume of HECA project gasification solid waste. The amount of waste generated from the HECA facility would result in a significant increase in per capita disposal and reduce the diversion and recycling rate below the 50 percent State-mandate. KCWMD provided comments to the Kern County Board of Supervisors which outlined potential impacts and proposed mitigation for the HECA project.

Staff has proposed conditions of certification **WASTE-1**, **WASTE-2**, **WASTE-3**, **WASTE-4**, **WASTE-7** and **WASTE-8** to address site contamination, waste reporting requirements, and constituent test requirements.

CONCLUSIONS

Although the management of the nonhazardous and hazardous waste generated during construction and operation of HECA would comply with applicable waste management laws, ordinances, regulations, and standards provided that the measures proposed in the AFC and staff's proposed conditions of certification are implemented, HECA as currently proposed will cause a significant waste management impacts to Kern County. The project will produce a significant amount of operational waste and push Kern County into non compliance according to AB939 and SB1016.

To help ensure and facilitate ongoing project compliance with LORS, staff proposes conditions of certification **WASTE-1** through **10.** These conditions would require the project owner to do all of the following:

- Ensure that existing waste on the project site is identified and characterized, and that any contamination identified is remediated as necessary, with appropriate professional and regulatory agency oversight (**WASTE-1**, **2**, and **3**).
- Obtain a hazardous waste generator identification number (**WASTE-5**).
- Prepare Construction Waste Management and Operation Waste Management Plans detailing the types and volumes of wastes to be generated and how wastes would be managed, recycled, and/or disposed of after generation (**WASTE-4** and **7**).
- Report any waste management-related LORS enforcement actions and how violations would be corrected (**WASTE-6**).
- Ensure proper disposal of the gasification solids and ZLD salt cake (**WASTE-8** and **WASTE-9)**.

- **WASTE-7 and 8 a**re de**s**igned to decrease the project's impacts of waste disposal of the gasification solids on Kern County landfill capacity.
- Ensure that all spills or releases of hazardous substances are reported and cleaned-up in accordance with all applicable federal, state, and local requirements (**WASTE-10)**.

Existing conditions at the HECA project site include areas where prior site uses may have resulted in releases of hazardous substances or soil contamination. To ensure that the project site is investigated and remediated as necessary and to reduce any impacts from prior or future hazardous substance or hazardous waste releases at the site to a level of less than significant, staff proposes conditions of certification **WASTE-1**, **2**, **3**, **4**, **5** and **6**. These conditions would require the project owner to ensure that the project site is investigated and remediated as necessary; demonstrate that project wastes are managed properly; and ensure that any future spills or releases of hazardous substances or wastes are properly reported, cleaned-up, and remediated as necessary. Therefore, staff concludes that construction and operation of the proposed HECA project would not result in contamination or releases of hazardous substances that would pose a substantial risk to human health or the environment.

Regarding impacts of project wastes on existing waste disposal facilities, staff uses a waste volume threshold equal to ten (10) percent of a disposal facility's remaining capacity to determine if the impact from disposal of project wastes at a particular facility would be significant. The existing available capacity for the four Class III landfills that may be used to manage nonhazardous project wastes exceeds 56 million cubic yards. The HECA Project could pose a significant impact and could place the Kern County in jeopardy of non-compliance with mandated recycling goals. Conditions of Certification **WASTE-8**, **9** and **10** are proposed to decrease this impact.

As discussed in the **Socioeconomic Resources** section, the minority population in the six-mile buffer of the project site constitutes an environmental justice population as defined by Environmental Justice: Guidance under the National Environmental Policy Act. Staff has identified a significant adverse direct and cumulative impact resulting from the operation of the proposed project, but the impact does not significantly or adversely affect the identified environmental justice community. The direct and cumulative impact affects Kern County in regards to compliance with Public Resources Code section 40000 et seq. Therefore, there is no **WASTE MANAGEMENT** environmental justice issues related to this project and no environmental justice populations would be significantly, adversely, or disproportionately impacted.

OUTSTANDING INFORMATION REQUIRED FOR COMPLETION OF THE FSA/FEIS

1. Staff was not provided a breakdown of types and quantities of nonhazardous and hazardous waste that will be generated from the OEHI component of HECA to confirm that the project will not have an impact on Kern County landfills. This data would be needed for staff to complete an assessment of potential impacts

Staff needs the results of waste characterization tests in accordance with to Title 22, California Code of Regulations, Division 4.5, section 66262.10 on coal and petcoke mixes using the Mitsubishi gasifier in Japan using processing methods representative of those to be used for project operation. The purpose of the testing is to determine whether the gasification solids would be hazardous or non-hazardous. This information is needed to further evaluate how the waste can be disposed of and whether it is feasible to market the solids for other uses. The information should include a description of the waste stream, an evaluation of where the residual material is suitable for disposal, identification of facilities that would accept the volume of waste generated, a letter from the facility demonstrating they would accept the waste, and evidence the disposal of the waste would be in compliance with Kern County waste disposal requirements. If the project owner proposes to market the solids for use as Supplementary Cementitious Materials or other purposes, then a detailed report indicating what uses can be marketed and letters of intent from prospective purchases should be included.

2. The project owner should enter into an Agreement with DTSC for the purpose of fully characterizing and if necessary remediating the site property so that it is in the appropriate condition to allow for future use. In addition based on the type of agreement with DTSC the applicant should conduct the necessary site characterization to determine if site remediation is needed and if so what the scope of remediation would be prior to the FSA.

3. Staff needs information on additional waste streams that would result from the addition of the limestone fluxant such as total tons and cubic yards. The applicant shall also provide information on the increased amount of gasification solids in tons and cubic yards.

PROPOSED CONDITIONS OF CERTIFICATION

WASTE-1 The project owner shall prepare and submit to the CPM a Soils Management Plan (SMP) prior to any earthwork. The SMP must be prepared by a California Registered Geologist or a California Registered Civil Engineer with sufficient experience in hazardous waste management. The SMP shall be updated as needed to reflect changes in laws, regulations or site conditions. An SMP summary report, which includes all analytical data and other findings, must be submitted once the earthwork has been completed. Topics covered by the SMP shall include, but not be limited to:

- Land use history, including description and locations of known contamination.
- The nature and extent of previous investigations and remediation at the site.
- The nature and extent of unremediated areas at HECA.
- A listing and description of institutional controls, such as the County's excavation ordinance and other local, state, and federal regulations and laws that would apply to HECA.
- Names and positions of individuals involved with soils management and their specific role.

- An earthwork schedule.
- A description of protocols for the investigation and evaluation of historically related chemicals such as DDE and previously unidentified contamination that may be potentially encountered, including any temporary and permanent controls that may be required to reduce exposure to onsite workers, visitors and the public.
- Requirements for site-specific Health and Safety Plans (HSPs) to be prepared by all contractors at HECA. The HSP should be prepared by a Certified Industrial Hygienist and would protect onsite workers by including engineering controls, personal protective equipment, monitoring, and security to prevent unauthorized entry and to reduce construction related hazards. The HSP should address the possibility of encountering subsurface hazards including hazardous waste contamination and include procedures to protect workers and the public.
- Hazardous waste determination and disposal procedures for known and previously unidentified contamination.
- Requirements for site specific techniques at the site to minimize dust, manage stockpiles, run-on and run-off controls, waste disposal procedures, etc.
- Copies of relevant permits or closures from regulatory agencies.

Verification: At least 45 days prior to any earthwork, the project owner shall submit the SMP to the CPM for review and approval. The SMP shall also be submitted to the Sacramento office of the California Department of Toxic substances Control (DTSC) for review and comment. All earthworks at the site shall be based on the SMP. A SMP summary shall be submitted to CPM and DTSC within 25 days of completion of any earthwork.

WASTE-2 The project owner shall hire an experienced and qualified Professional Engineer or Professional Geologist with experience in remedial investigation and feasibility studies, which shall be available for consultation during site construction, excavation, and grading activities.

The Professional Engineer or Professional Geologist shall be given full authority by the project owner to oversee any earth moving activities that have the potential to disturb contaminated soil.

Verification: At least 30 days prior to the start of site mobilization, the project owner shall submit the resume showing the required experience to the CPM for review and approval.

WASTE-3 If potentially contaminated soil is identified during site construction, excavation, or grading at either the proposed site or along linear facilities, as evidenced by discoloration, odor, detection by handheld instruments, or other signs, the Professional Engineer or Professional Geologist shall inspect the site, determine the need for sampling to confirm the nature and extent of contamination, and provide a written report to the project owner, representatives of DTSC, and the CPM stating the recommended course of action.

The Professional Engineer or Professional Geologist shall have the authority to temporarily suspend construction activity at that location for the protection of workers or the public when the nature or extent of contamination warrants such suspension in the judgment of the Professional Engineer or Professional Geologist. If, in the opinion of the Professional Engineer or Professional Geologist, significant remediation may be required, the project owner shall contact the CPM and representatives of the Department of Toxic Substances Control for guidance and possible oversight.

Verification: The project owner shall submit any final reports filed by the Professional Engineer or Professional Geologist to the CPM within 5 days of applicant's receipt of reports. The project owner shall notify the CPM within 24 hours of any orders issued to halt construction.

WASTE-4 The project owner shall prepare a Construction Waste Management Plan for all wastes generated during construction of the facility, and shall submit the plan to the CPM for review and approval. The plan shall contain, at a minimum, the following:

- a description of all construction waste streams, including projections of frequency, amounts generated, and hazard classifications;
- management methods to be used for each waste stream, including temporary on-site storage, housekeeping and best management practices to be employed, treatment methods and companies providing treatment services, waste testing methods to assure correct classification, methods of transportation, disposal requirements and sites, and recycling and waste minimization/source reduction plans;
- a method for collecting weigh tickets or other methods for verifying the volume of transported and or location of waste disposal; and,
- a method for reporting to demonstrate project compliance with construction waste diversion requirements of 50 percent pursuant to the CalGreen Code Section 708 construction Waste Reduction, Disposal and Recycling.

Verification: The project owner shall submit the Construction Waste Management Plan to Kern County for review and the CPM for review and approval no less than 30 days prior to the initiation of construction activities at the site.

WASTE-5 The project owner shall obtain a hazardous waste generator identification number from the United States Environmental Protection Agency prior to generating any hazardous waste during construction and operations.

Verification: The project owner shall keep a copy of the identification number on file at the project site and provide documentation of the hazardous waste generation and notification and receipt of the number to the CPM in the next scheduled Monthly Compliance Report after receipt of the number. Submittal of the notification and issued number documentation to the CPM is only needed once unless there is a change in ownership, operation, waste generation, or waste characteristics that requires a new notification to USEPA. Documentation of any new or revised hazardous waste generation notifications or changes in identification number shall be provided to the CPM in the next scheduled compliance report.

WASTE-6 Upon notification of any impending waste management-related enforcement action related to project site activities by any local, state, or federal authority, the project owner shall notify the CPM of any such action taken or proposed against the project itself, or against any waste hauler or disposal facility or treatment operator with which the owner contracts for the project, and describe the owner's response to the impending action or if a violation has been found, how the violation would be corrected.

Verification: The project owner shall notify the CPM in writing within 10 days of receiving written notice from authorities of an impending enforcement action. The CPM shall notify the project owner of any changes that would be required in the way project-related wastes are managed as a result of a finalized action against the project.

WASTE-7 The project owner shall submit an Operation Waste Management Plan to the Compliance Project manager (CPM) for review and approval. The plan shall contain, at a minimum, the following:

- A detailed description of all operation and maintenance waste streams, including projections of amounts to be generated, frequency of generation, and waste hazard classifications;
- Management methods to be used for each waste stream, including temporary on-site storage, housekeeping and best management practices to be employed, treatment methods and companies providing treatment services, waste testing methods to assure correct classification, methods of transportation, disposal requirements and sites, and recycling and waste minimization/source reduction plans;
- Information and summary records of conversations with the local CUPA and DTSC regarding any waste management requirements necessary for project activities. Copies of all required waste management permits, notices, and/or authorizations shall be included in the plan and updated as necessary;
- A section incorporating the Gasification Waste Diversion Plan;
- A detailed description of how facility wastes would be managed, and any contingency plans to be employed, in the event of an unplanned closure or planned temporary facility closure; and
- A detailed description of how facility wastes would be managed and disposed of upon closure of the facility.

Verification: The project owner shall submit the Operation Waste Management Plan to the CPM for approval no less than 30 days prior to the start of project operation. The project owner shall submit any required revisions to the CPM within 20 days of notification from the CPM that revisions are necessary. The project owner shall also document in each Annual Compliance Report the actual volume of wastes generated and the waste management methods used during the year; provide a comparison of the actual waste generation and management methods used to those proposed in the original Operation Waste Management Plan; and update the Operation Waste Management Plan as necessary to address current waste generation and management practices.

WASTE-8 During project operation the project owner shall periodically conduct waste characterization tests in accordance with Title 22, California Code of Regulations, Division 4.5, section 66262.10 on all coal and petcoke mixes being used for operation. The purpose of the testing is to determine whether the gasification solids would be hazardous or non-hazardous and if there is a change in characteristics when the source of coal or petcoke changes or the percentages used for power generation are changed. This information would also be used to develop a Gasification Waste Diversion Plan (GWDP) that would identify how and where the wastes would be disposed and whether it is feasible to market the solids for other uses. The GWDP would be submitted to Kern County for review and comment and the CPM for review and approval. The GWDP shall include a description of the waste stream, an evaluation of where the residual material is suitable for disposal, identification of facilities that would accept the volume of waste generated, a letter from the facility demonstrating they would accept the waste, and evidence the disposal of the waste would be in compliance with Kern County waste disposal requirements. If the project owner proposes to market the solids for use as Supplementary Cementitious Materials or other purposes, then a detailed report indicating what uses can be marketed and letters of intent from prospective purchases should be included. The test results, and method and location of gasification solid disposal shall also be reported in the Annual Compliance Report required in Condition of Certification **WASTE-7.**

Verification: The project owner shall provide to the CPM 60 days prior to operation for review and approval a report detailing the general and chemical characteristics of the gasification solids after test runs of the plant with the planned fuel mixture have been completed. The project owner shall also provide an initial GWDP developed based on data from preliminary waste characterization tests and a preliminary plan for solids disposal and marketing based on these test results. The project owner shall provide to the CPM 60 days prior to a change in the fuel mixture or fuel source, a plan showing the proposed changes and a discussion of the anticipated changes in character of the waste solids and any new information that may be available indicating there would be no significant change in the waste character for CPM review and approval. The project owner shall provide to the CPM within 30 days a report summarizing the results of waste characterization tests and indicate whether they can continue to be disposed of as indicated in the GWDP or whether the GWDP should be updated to address new information. If the GWDP must be updated a draft GWDP shall be submitted to the CPM for review within 60 days of notification by the CPM.

WASTE-9 The project owner shall ensure that the Zero Liquid Discharge (ZLD) salt cake is tested pursuant to Title 22, California Code of Regulations, Division 4.5, section 66262.10 and report the findings to the CPM. The handling, testing, and disposal methods for sludge shall be identified in the Operation Waste Management Plan required in Condition of Certification **WASTE-7**.

Verification: The project shall report the results of ZLD salt cake testing to the CPM within seven days of sampling. If two consecutive tests show that the salt cake is non-hazardous, the project owner may apply to the CPM to discontinue testing. The test results and method and location of ZLD salt cake shall also be reported in the Annual Compliance Report required in Condition of Certification **WASTE-7**.

WASTE-10 The project owner shall ensure that all accidental spills or unauthorized releases of hazardous substances, hazardous materials, or hazardous waste are documented and remediated, and that wastes generated from the accidental spills and unauthorized releases are properly managed and disposed of in accordance with all applicable federal, state, and local requirements.

Verification: The project owner shall document management of all accidental spills and unauthorized releases of hazardous substances, hazardous materials, and hazardous wastes that occur on the project property or related linear facilities. The documentation shall include, at a minimum, the following information: location of release; date and time of release; reason for release; volume released; how release was managed and material cleaned up; amount of contaminated soil and/or cleanup wastes generated; if the release was reported; to whom the release was reported; release corrective action and cleanup requirements placed by regulating agencies; level of cleanup achieved and actions taken to prevent a similar release or spill; and disposition of any hazardous wastes and/or contaminated soils and materials that may have been generated by the release. A copy of the accidental spill or unauthorized release documentation shall be provided to the Compliance Project manager (CPM) within 30 days of the date the release was discovered.

RECOMMENDED MITIGATION MEASURES

The applicant will work with DTSC to implement recommended **Waste Mitigation Measure 1.**

WASTE-1 OEHI shall keep DOE and DTSC informed of construction areas and implement all appropriate and applicable safety measures and LORS to limit employee and contractor exposure to hazardous materials.

The applicant will work with Kern County to implement **Waste Mitigation Measure-2**.

WASTE-2 The OEHI EOR project owner shall consult with Kern County to develop a waste management and diversion plan that would ensure the county can maintain state compliance and mitigate potentially significant cumulative impacts from EHOR legacy landfills.

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WASTE MANAGEMENT - FIGURE 1

Hydrogen Energy California - Geophysical Survey Map- Adohr Road and Dairy Road Kern County, California

WASTE MANAGEMENT

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: Amended AFC for Hydrogen Energy California 08-AFC-8A

WATER SUPPLY

Mike Conway, PG, John Fio, and Steve Deverel, PG

SUMMARY OF CONCLUSIONS

Staff is supportive of projects that use degraded water supplies. The Buena Vista Water Storage District (BVWSD) service area is known to be impacted by shallow, and in some cases, saline ground water. Removal of water within the district that has limited use, or may improve crop productivity, would be supported by staff for use in power plant cooling.

Staff was unable to obtain geologic reports that were prepared for Buena Vista Water Storage District (BVWSD) specifically to evaluate the impact of the proposed water supply. Much of the data that staff had sought was relied upon to produce the original Application for Certification (AFC) Hydrogen Energy California (08-AFC-8), however this data is still relevant to the current proceeding (08-AFC-8A) because the proposed project's water supply has not changed significantly. Staff Data Request 103, dated October 12, 2009, states, "Please provide a copy of the completed document, or most recent draft, of the following report: "An Evaluation of the Geology, Hydrology, Well Placements and Potential Impacts of the Buena Vista Water Storage District's proposed Brackish Groundwater Remediation Project", prepared by Sierra Scientific Services, Bakersfield, California, dated 2009." BVWSD has indicated in their Final Environmental Impact Report for the Brackish Groundwater Remediation Program (BGRP) that this and other supporting reports provide the scientific basis for development of the proposed water supply through the BGRP. The Kern Water Bank Authority, Sierra Club, and the California Department of Water Resources have also independently inquired about this report as well and have not received a copy that we are aware of. Without these reports or other substantial data, staff could not evaluate how BVWSD and the applicant analyzed the potential impacts and feasibility of the proposed water supply. Since these reports were not made available, staff conducted an independent assessment.

Staff conducted a workshop on February 20, 2013, to discuss the preliminary results of the independent assessment of the proposed project water supply. Staff expended a considerable amount of time and effort analyzing the available information and repeatedly requesting the additional information to substantiate the applicant's conclusions related to water supply impacts. Staff's conclusions are presented below. At the workshop BVWSD indicated they have additional data that was not considered in staff's analysis. They offered to provide additional information and requested staff reanalyze the potential project impacts. BVWSD indicated some data is confidential and requested that staff work directly with BVWSD to obtain the data and ensure it is protected in accordance with state law. Staff agreed and transmitted data requests to BVWSD on March 21, 2013. Staff has not received the data or met with BVWSD since the workshop and is awaiting the data for further analysis in a revised staff assessment. Much of the analysis presented below is the same or similar to that presented in the draft preliminary staff assessment at the workshop.

On March 19, 2013, BVWSD also submitted a detailed comment letter on the technical merits of the draft preliminary analysis. Many of the comments relied on interpretation of data that is not available to staff. Staff will address these comments in a future revision of the staff assessment once the data has been received.

Based on a preliminary assessment of the proposed Hydrogen Energy California (HECA) project, the California Energy Commission (Energy Commission) staff preliminarily concludes that development of the project's proposed industrial water supply could result in the following without further analysis:

1. ***The project pumping could result in well interference and lower water levels in neighboring wells.***
   The applicant utilized a three-dimensional numerical groundwater-flow model and superposition to simulate the proposed well field and quantify water level drawdown due to project pumping. The applicant's model simulated drawdown values at select well locations that range from -0.7 to 12.0 feet; drawdown less than zero indicate that as a result of simulated recharge water levels increase during the 25-year simulation period. However, staff believes the model incorrectly includes simulated recharge, ignores potentially relevant boundaries, and may use inappropriate parameter values. Staff modifications to correct and test the model increased simulated drawdown. A worst-case simulation showed that drawdowns range between 5.1 and 34.2 feet.

   Staff employed a significance threshold of 15-feet for well interference. Simulated drawdown by the applicant's model did not exceed the threshold at any well locations considered. However, simulated drawdown by the modified model (no-flow boundary added and no recharge) exceeded the threshold at one location. Additional model tests conducted by staff indicate the drawdown threshold was exceeded at one location using the above staff-modified model with reduced storativity (0.007), and the threshold was exceeded at 13 well locations using the staff-modified model with reduced storativity and increased anisotropy. These results indicate there is uncertainty in the magnitude and scope of potential well interference due to uncertainty in hydrogeologic conditions.

2. ***The proposed industrial supply wells may induce the inflow of relatively poor quality groundwater into a zone of relatively higher water quality within the water-supply aquifer beneath the Buttonwillow Service Area.***
   Staff cannot verify that the project's proposed well configuration protects water quality beneath the Buttonwillow Service Area. The proposed industrial supply wells may induce the inflow of relatively poor quality groundwater into a zone of relatively higher water quality within the water-supply aquifer beneath the Buttonwillow Service Area. The depth to the base of freshwater beneath the well field is about 700 feet, and up-coning of the underlying salt water is a potentially important factor affecting inflow of salt into the pumped zone. The applicant's model indicates a substantial proportion of extracted groundwater (58-percent) likely would originate at depths below the proposed extraction wells. The staff-modified model with reduced storativity and increased anisotropy simulates a lesser proportion (15-percent). For example, assuming a minimum salinity for brackish groundwater of 2,000 mg/L, the staff-modified groundwater-flow model results suggest a new salt load in this up-coning that may be 15,400 tons per year. Because the underlying salt water has a different composition from the overlying groundwater, the up-coning may potentially

increase TDS concentrations in the local water supply aquifer and shift the water from a calcium-sulfate to sodium-chloride dominated water.

Staff provides this data to show that the quantification of the proposed water quality benefit to the region from the BGRP must include a budget that shows the proportions of water sources from the reportedly higher salt loads beneath the wells.

3. ***The project's pumping could exacerbate overdraft in the Kern County subbasin.***
   Observed water levels in wells spanning the period 1974-2001 show a statistically significant upward trend at the 95 percent confidence level. The significant upward trends range from 0.28 feet per year (ft/yr) to 1.27 ft/yr. The average trend suggests the annual increase in groundwater storage beneath Buena Vista Water Storage District's Buttonwillow Service Area ranged from about 4,600 to 6,100 AF/yr (assumed specific yield values ranging from 0.15 to 0.20, respectively). The geometric mean storativity from local aquifer test results (0.007) is substantially lower than the applicant's assumed specific yield, and estimated groundwater storage changes may therefore be considerably less than 4,600 to 6,100 AF/yr. The planned well field extraction rate (7,500 AF/yr) may therefore exceed the annual storage increase characterized by historical water level trends.

4. ***The project pumping could reverse local water level increases and increase the threat to the California Aqueduct from subsidence.***
   If the proposed well field extraction indeed exacerbates overdraft in the Kern County subbasin, staff's analysis indicates it could also exacerbate subsidence in areas near the California Aqueduct. There is no historical evidence for subsidence in the Buttonwillow Service Area or immediate vicinity of the proposed well field. However, the Buttonwillow Service Area is located adjacent to two major historic subsiding areas in the southern San Joaquin Valley. Observed Buttonwillow Service Area groundwater level data indicate water levels have increased on average since 1970; however if pumping causes these trends to reverse and water levels decline below historical lows it could increase the risk of land surface subsidence.

5. ***The project use of the proposed water supply may not be consistent with Energy Commission and other state water policies.***
   Staff conducted several methods of analysis to estimate the expected TDS concentrations in water produced by extraction wells operating in the proposed well field. The results indicated an expected concentration range from 945 mg/L to 3,730 mg/L. This range in concentrations suggests water of sufficient quality for other beneficial uses may be produced during pumping from the proposed well field. Staff notes that the proposed power plant would use water at an extremely high rate, primarily for evaporative cooling. Staff also cannot verify that the proposed groundwater for use is the worst water quality available, or that the use satisfies state and Energy Commission policies regarding the use and conservation of water resources. Staff is therefore unable to verify that the proposed groundwater pumping for industrial cooling is reasonable.

   Alternative water supplies have not been adequately evaluated by the applicant. In staff Data Request 97 dated October 12, 2009, staff initially introduced this issue. Staff issued 11 Data Requests on November 12, 2010, again inquiring about water supply and alternatives. In a staff Issues ID Report from July 10, 2012 staff reiterated that water supply alternatives that appear to be feasible are sources of shallow, degraded groundwater to the north of the proposed well field, other well field construction and pumping configurations, or surplus water from the Elk Hills oil field operation. These or other alternatives should be evaluated in detail to ensure there is no other environmentally desirable or economically feasible supply.

6. ***Staff cannot verify a persistent source of saline water flowing eastward towards the Buttonwillow Service Area.***
   The applicant contends that the source of saline water impacting the district originates in the Temblor Range west of the Buttonwillow Service Area. Staff cannot verify a persistent source of saline water flowing eastward. Though waters of elevated salt concentrations exist in the Buttonwillow Service Area, its source cannot be verified. Staff shows for example how significant the contribution of more saline water beneath the well could be relative to water from the west. Local agricultural management practices also have significant influence on groundwater quality, which make determination of the source of salts additionally difficult. Geologic depositional environment may also have influence on the character of the soil and groundwater in the area. Staff considers the identification of the source of salts an important piece of the foundation of a remediation program. A 25-year or longer remediation pumping program should adequately identify the location, mass, and mobility of a contaminant source, not just its assumed present location.

7. ***Applicant dismisses potentially feasible water alternatives because proposed use is so high.***
   An extremely high water demand of the proposed project is cited by the applicant as reason to eliminate many otherwise feasible alternative supplies. Water alternatives dismissed by the applicant such as municipal wastewater from Bakersfield, oil field wastewater, or BVWSD Target Area A water, were eliminated because they can't supply the proposed project's entire water supply. However it is unreasonable to dismiss all of these options when any one of them could provide up to 50 percent of the project's water needs.

   In light of the project potential impacts to water resources, alternative water supplies should be considered. A high water use scenario should not preclude consideration of alternate water sources.

UNRESOLVED ISSUES

INDUSTRIAL WATER SUPPLY

A fundamental requirement for a power plant licensed by the Energy Commission is to demonstrate that the proposed water use is reasonable relative to current technology and regional and state water needs. In essence, staff believes that a power plant must demonstrate that its use constitutes the least amount of the most degraded source available.

The project's most significant unresolved issue in terms of the industrial water supply is a failure to demonstrate that the project uses the least amount of the worst quality water available. Furthermore, seemingly reasonable alternative water supplies are not given rigorous consideration. For example, BVWSD's Final Environmental Impact Report (FEIR) describes that the second phase of their proposed Brackish Groundwater Remediation Program (BGRP) could provide up to 4,500 AF/y of brackish groundwater. The water source is shallow groundwater that is already problem water and impacting crop type and yield. Accordingly, this alternative source is worthy of consideration for at least some portion of industrial supply water for the HECA plant. In light of this potentially superior alternative, staff expects a more thorough analysis of its viability. Staff will prepare an independent analysis of the feasibility of using additional sources of water produced by the BGRP, in addition to the proposed supply.

The applicant has also neglected to adequately consider a dry-cooled project alternative. As stated in this analysis, in some cases the impact to water resources may be proportional to the volume pumped, and likewise, any decrease in water use could contribute to a lessening of the impact, proportional to the decrease. It is reasonable to consider dry cooling to reduce the potential project's water consumption, even if it would not reduce such consumption to zero. Dry cooling has the potential to: a) reduce project water demand to roughly 17-percent of the currently proposed amount, and thereby b) reduce water costs by approximately $70,000,000 over a 25-year period.

Applicant responses to staff inquiries about dry cooling, including Data Response 203, January 2013, rely on references that don't reflect the current state of power plant development n California, and do not consider project and site specific conditions. Since the data responses have been inadequate for staff to complete an analysis of the feasibility of dry-cooling, staff will prepare an independent analysis for the Final Staff Assessment.

As discussed above, the project's current industrial supply well field could create three significant impacts.

1. The project's pumping could exacerbate overdraft in the Kern County subbasin.
2. The project's pumping could potentially induce a significant proportion of degraded water to move into the local water-supply aquifer, further degrading local water supplies.
3. The project's pumping could also reverse local water level increases and increase the threat to the California Aqueduct from subsidence.

Staff has provided preliminary conditions of certification that can be used to mitigate potential impacts from basin overdraft, well interference, and subsidence. However, these conditions are only applicable if it can be shown through further analysis that potential groundwater quality impacts identified herein are not a concern. In addition, given staff's current conclusions, a more rigorous analysis of alternatives must be conducted to show there is no other economically feasible and environmentally desirable water supply available consistent with Energy Commission and other state water policy.

INTRODUCTION

This section of the Preliminary Staff Assessment (PSA) analyzes potential impacts to water resources from the construction and operation of the Hydrogen Energy California

(HECA) project. Where the potential of a significant impact is identified, staff proposes mitigation to reduce the significance of the impact and, as appropriate, recommends conditions of certification.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

The following federal, state, and local environmental LORS were established for the HECA project and similar facilities to ensure the best and appropriate use and management of water resources. Additionally, the requirements of these LORS are specifically intended to protect human health and the environment. The potential for project compliance with these LORS is a major component of staff's determination regarding the significance and acceptability of the HECA project with respect to the use and management of water resources.

Water Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Federal LORS	
-	-
State LORS	
California Constitution, Article 10, Section 2, and California Water Code (CWC), Section 100	These laws require that the water resources of the state be put to beneficial use to the fullest extent possible and that the waste, unreasonable use or unreasonable method of use of water be prevented. The laws also require that conservation of such water be exercised with a view to the reasonable and beneficial use of the water in the interest of the people and for the public welfare.
CWC, Division 7, Section 13000 et seq. — Porter-Cologne Water Quality Control Act	The Porter-Cologne Water Quality Control Act (Porter-Cologne) was established to protect the water quality and beneficial uses of waters of the state. The law gives broad authority to the State Water Resources Control Board (SWRCB) and nine Regional Water Quality Control Boards (RWQCBs) to establish water quality standards and discharge prohibitions, issue waste discharge requirements, and implement provisions of the federal Clean Water Act. Under Porter-Cologne, "waters of the state" include both surface and groundwaters.
CWC, Sections 13240, 13241, 13242, 13243, & Water Quality Control Plan for the Sacramento and San Joaquin River Basin – Region 5 (Basin Plan)	The Basin Plan establishes the beneficial use designations and water quality objectives for surface water and groundwater in the Central Valley Region. It also describes implementation plans and measures necessary to achieve standards and ensure compliance with both regional and statewide water quality plans and policies; and acts as the comprehensive water quality planning document for the Central Valley Region.
CWC, Section 13550	This section of Porter-Cologne establishes that the use of potable domestic water for non-potable uses (including industrial use) is a waste or an unreasonable use of the water if recycled water is available and meets the following conditions: the quality and quantity of the reclaimed water are suitable for the use; the cost is reasonable; the use is not detrimental to public health; and the use will not impact

	downstream users or biological resources.
CWC, Sections 231 and 13700 et seq.	Section 231 and Division 7, Chapter 10 of the Water Code establish the authority for development and implementation of minimum water well standards for the state. Minimum standards for the construction and destruction of water wells are established in Bulletins 74-81 and 74-90, California Well Standards, by the California Department of Water Resources (DWR). A well completion report must be filed with DWR for each well that is constructed, reworked, or destroyed.
Title 17, California Code of Regulations (CCR), Division 1, Chapter 5	This chapter of the CCR addresses the requirements for backflow prevention and cross connections of potable and non-potable water lines.
Title 22 , CCR, Division 4 — Environmental Health	Title 22, Division 4 is implemented by the California Department of Public Health (CDPH) (formerly known as the California Department of Health Services). The regulations address requirements for drinking water standards, water treatment and operator certification, and water recycling criteria. Section 64431 establishes the public drinking water maximum contaminant levels (MCLs), including an MCL for nitrate of 45 mg/L (equivalent to 10 mg/L for nitrate as nitrogen). Section 64449 establishes secondary drinking water standards, including a recommended total dissolved solids (TDS) level of 500 mg/l, with an upper limit of 1,000 mg/l, and a short term level of 1,500 mg/l. Article 3 also requires monitoring of potable water wells defined as non-transient, non-community water systems (serving 25 people of more for more than six months).
The Safe Drinking Water and Toxic Enforcement Act of 1986, Health and Safety Code 25241.5	Prohibits discharge of chemicals known to cause cancer or reproductive toxicity into drinking water sources.
Local LORS	
Kern County General Plan-Land Use Element: Resource Goals, Objectives, and Policies Policy LU 1.4.5	Ensures that an adequate water supply is available for industrial uses.
State Policies and Guidance	
State Water Resources Control Board Resolution No. 68-16	The “Antidegradation Policy” mandates that: 1) existing high quality waters of the state are maintained until it is demonstrated that any change in quality will be consistent with maximum benefit to the people of the state, will not unreasonably affect present and anticipated beneficial uses, and will not result in waste quality less than adopted policies; and 2) requires that any activity which produces or may produce a waste or increased volume or concentration of waste and which discharges or proposes to discharge to existing high quality waters, must meet WDRs which will result in the best practicable treatment or control of the discharge necessary to assure that: a) a pollution or nuisance will not occur and b) the highest water quality consistent with maximum benefit to the people of the state will be maintained.

SWRCB Resolution No. 75-58 — Water Quality Control Policy on the Use and Disposal of Inland Waters Used for Power Plant Cooling (adopted June 19, 1975).	This SWRCB policy specifically addresses the use of inland waters for power plant cooling. The policy states that fresh inland waters should only be used for power plant cooling if other sources or other methods of cooling would be environmentally undesirable or economically unsound. The policy establishes a general hierarchy for cooling water whereby the lowest quality water reasonably available is to be utilized for evaporative cooling processes. It also includes cooling water discharge prohibitions.
SWRCB Resolution No. 88-63 —Sources of Drinking Water Policy (Revised by Resolution 2006-0008)	This policy states that all surface and groundwaters of the state are considered to be suitable, or potentially suitable, for municipal or domestic water supply, and should be designated as such by the RWQCBs, with the exception of certain waters (such as contaminated sources or process wastewaters), or waters that exceed 3,000 mg/L total dissolved solids (TDS).
State Water Resources Control Board Resolution No. 2005-0006	Adopts the concept of sustainability as a core value for State Water Board programs and directs its incorporation in all future policies, guidelines, and regulatory actions.
The 2003 California Energy Commission *Integrated Energy Policy Report (IEPR)*	The *2003 IEPR* was developed and adopted pursuant to Public Resources Code sections 25301 and 25302. It includes a water and wastewater policy stating that the Energy Commission will approve the use of fresh water for cooling purposes by power plants it licenses only where alternative water supply sources and alternative cooling technologies are shown to be "environmentally undesirable" or "economically unsound." In addition, the policy states that the Energy Commission will also require that zero-liquid discharge technologies be used to manage project wastewater unless such technologies are shown to be "environmentally undesirable" or "economically unsound."

PROPOSED PROJECT

SETTING AND EXISTING CONDITIONS

The proposed Hydrogen Energy California (HECA) project would be constructed on a 453-acre site located seven miles west of Bakersfield and a mile and half northwest of Tupman, western Kern County. The site is contained within Section 10 of Township 30 South, Range 24 East. The site is also just north of the West Side/Outlet Canal, the Kern River Flood Control Channel, and the California Aqueduct. Agriculture is the primary land use at the site and local vicinity; onions, cotton, and alfalfa are currently being cultivated on the proposed project site. The project site is approximately 285 feet above mean sea level (amsl) (HECA 2012b).

The proposed project would require extensive construction and groundwater pumping in close proximity to the California Aqueduct. The proposed power plant would be built within 0.5 miles of the aqueduct and the proposed groundwater supply would be pumped within approximately 2 miles of the aqueduct. The California Aqueduct is a significant conveyance component of the State Water Project (SWP) managed by the California Department of Water Resources, which begins at the Sacramento-San

Joaquin River Delta and continues south through the Central Valley, over the Tehachapi Mountains, and into southern California. The State Water Project provides a water supply for up to 23 million Californians and up to 755,000 acres of irrigated agriculture and is a vital water supply for many southern Californians. This analysis pays particular attention to impacts to the California Aqueduct (HECA 2012b).

The HECA project would be built along the west side of the San Joaquin Valley river basin, contained between the Coast Ranges to the west, the Emigdio and Tehachapi Mountains to the south, and the Sierra Nevada to the East. The proposed site is approximately two miles north of the Elk Hills oil field, the location of proposed carbon dioxide injection related to the project. The Elk Hills form the surface expression of an anticline composed of gravel and mudstone (HECA 2012b).

The site is located within the Kern County groundwater subbasin of the San Joaquin Valley Basin. The subbasin covers almost 2,000,000 acres within Kern County. Two main water units exist within the Kern County subbasin, the Plio-Pleistocene Tulare Formation and the overlying Pleistocene alluvium/stream deposits. Within the Kern County subbasin further hydrogeologic subunits are defined based on geologic structures that create some degree of separation that is not fully understood. The proposed process water supply would be drawn from and used within the Buttonwillow subbasin. The site is located along the course of the old Kern River. The site is uniquely situated along the axis of the Kern County subbasin and is underlain by 600-700 feet of interbedded alluvial deposits (BVW 2010a). The inferred subbasins in the region are shown in **Water Figure 1**.

Surface water flow is northward from the terminal drainage basin. The proposed project site is north of both the Kern and Buena Vista ephemeral lakebeds and is in the Tulare Hydrologic Unit. Surface water in the southern portion of the subbasin discharges toward the north, toward Goose Lake lakebed via various drainage canals.

The Central Valley climate is semi-arid, creating hot dry summers and mild winters. Average daily summer temperatures recorded between 1937 and 2006 range between the 70s and 80s, while average daily winter temperatures range between the 40s and 50s. Average annual precipitation during the same period was 6.23 inches (HECA 2012b).

Local Water Management

Both the proposed power plant and proposed water supply wells are located within the Buena Vista Water Storage District (BVWSD) service area. The district contains two sub-service areas within it, the Buttonwillow Service area which is approximately 46,600 acres and the Maples Service Area which is approximately 5,000 acres. Approximately 45,000 acres of the district is developed and 35,000 acres of district land are farmed annually for field and row crops. **Water Figure 1** shows the location of the service areas (FEIR 2009). The project site is within the Buttonwillow Service Area.

BVWSD manages supply and demand within the district which has been recorded during the period 1970 through 2007 (BVW 2010a). The district relies on groundwater and various surface water deliveries to supply its customers. The district's most significant supply is provided by a Kern River entitlement dating back to 1888, known as the Miller-Haggen Agreement. As a second-point interest (State Water Rights Board Decision D 1196 defines First, Second, and Lower Service Areas, or interests) to the Kern River water supply, the BVWSD is entitled to about 158,000 AF/y. The district also has a contract with the Kern County Water Agency (KCWA) to receive 21,300 AF/y from the State Water Project (SWP). In years when it is available, the district also has a surplus entitlement of 3,750 AF/y. The district also receives Central Valley Project water from the Friant-Kern Canal water to supplement its entitlements (BVW 2010a).

KCWA is one of 29 SWP contractors. The KCWA was created in 1961 by the State Legislature and is the designated SWP contracting entity for local water districts in Kern County. KCWA is involved with various banking and recovery operations and also provides some flood control services. KCWA has contracts with 13 member agencies including Belridge Water Storage District, Berrenda Mesa Water Storage District, BVWSD, Cawelo Water District, Henry Miller Water District, Kern Delta Water District, Lost Hills Water District, Rosedale-Rio Bravo Water Storage District, Semitropic Water Storage District, Tehachapi-Cummings County Water District, Tejon-Castaic Water District, West Kern Water District, and Wheeler Ridge-Maricopa Water Storage District (KCWA 2010). The BVWSD is bounded by and operates in conjunction with these numerous water districts and agencies in the southern San Joaquin Valley as shown in **Water Figure 1**. The BVWSD is able to exchange its Kern River entitlements for other KCWA members' SWP water, due to the BVWSD's close proximity to the California Aqueduct (BVW 2010a). The BVWSD receives its SWP water from five turnouts along the California Aqueduct. The turnouts provide a direct, gravity-fed connection to the district's distribution system.

The Belridge Water Storage District (BWSD) is located immediately west of BVWSD's Buttonwillow Service Area. The 92,000 acre district has 121,508 acre-feet of SWP firm entitlement. The district is highly invested in pumping water from the California Aqueduct; aqueduct water is pumped from a canal altitude of 300 feet amsl uphill to an elevation of 500' amsl using up to 14,000 horsepower. The BWSD also participates in banking projects within Kern County, but extracts very little groundwater from beneath its district boundaries (BVW 2010a).

The West Kern Water District (WKWD) serves a population of approximately 25,000 people within a 250 square mile area located along the western border of Kern County. The WKWD supplies its customers with groundwater pumped from eight wells within the district. Current water demand is approximately 20,000 AF/y (BVW 2010a).

The Semitropic Water Storage District (SWSD) is located immediately east of the BVWSD. SWSD serves 300 customers located within 220,000 acres. The district also offers groundwater banking and storage services for various water districts in Kern County, Southern California, and the Bay Area. SWSD currently banks 700,000 acre-feet of water and has a capacity to bank 2.15 million acre-feet of water (SWSD 2010).

The Rosedale-Rio Bravo Water Storage District (RRBWSD) is located immediately southeast of the BVWSD. The RRBWSD spans approximately 43,000 acres and serves approximately 33,400 acres of cropland and 6,000 acres of urban area (USBR 2009).

The Kern Water Bank Authority (KWBA) owns about 20,500 acres located along the Kern River and directly southeast of the BVWSD. Similar to the BVWSD, the KWBA receives its water supply from the Kern River, the Friant-Kern Canal, and the California Aqueduct. The KWBA includes 80 supply wells, which have the capacity to recover 240,000 AF/y. The primary purpose of the water bank is to recharge, store, and recover water for the benefit of those participating in the program. The KWBA is a Joint Powers Authority, formed in 1995. Participants in the management of the water bank include Dudley Ridge Water District, Kern County Water Agency, Improvement District 4, Semitropic Water Storage District, Tejon-Castaic Water District, Westside Mutual Water Company, and Wheeler Ridge-Maricopa Water Storage District (KWB 2010).

Kern Water Bank (KWB) facilities are also located southeast of BVWSD. The KWB was formed in 1995 to manage banking facilities previously operated by DWR. The KWB has the capacity to store up to 1,000,000 acre-feet and extract up to 240,000 acre-feet per year. The facilities are jointly managed by Dudley Ridge Water District, KCWA (Improvement District 4), SWSD, Tejon-Castaic Water District, Westside Mutual Water Company, and Wheeler Ridge-Maricopa Water Storage District (BVW 2010a).

Water purveyors in the Kern County subbasin are engaged in joint groundwater management agreements. The interconnectivity of hydrogeological subunits within the greater Kern County subbasin requires a joint interest in protecting the shared groundwater resource. For instance, the Memorandum of Understanding (MOU) Regarding Operation and Monitoring of the BVWSD Groundwater Banking Program (2002) reflects the interest of many of the local water districts to safely manage groundwater in the Kern County subbasin. The districts that are party to the MOU include: BVWSD, Semitropic Water Storage District, Henry Miller Water District, Kern County Water Agency, Kern Delta Water District, Kern Water Bank Authority, Rosedale-Rio Bravo Water Storage District, and West Kern Water District. This agreement is hereafter referred to as MOU #1 (BVW 2010a).

Staff is aware of another agreement titled Memorandum of Understanding Regarding Operation and Monitoring of the Semitropic Groundwater Banking Project, signed September 14, 1994. The agreement was entered into by the following: Semitropic Improvement District of Semitropic Water Storage District, North Kern Water Storage District, Shafter Wasco Irrigation District, Southern San Joaquin Municipal Utility District, Shafter Wasco Irrigation District, Southern San Joaquin Municipal Utility District, Buena Vista Water Storage District, and Rosedale-Rio Bravo Water Storage District. This agreement is hereafter referred to as MOU #2 (BVW 2010a).

BVWSD is also engaged in two banking and recovery programs with their immediate neighbors. In 1983 BVWSD entered an agreement with the West Kern Water District and in 2002 with the Rosedale-Rio Bravo Water Storage District.

PROJECT DESCRIPTION

The proposed project would use a blend of coal and petroleum coke to produce hydrogen, which would then be used to fuel a combined cycle turbine. This 431-gross-megawatt (MW) plant would provide up to 300 MW of baseload power to the grid. The gasification block would capture 90 percent of raw syngas carbon, which would be transported to the Elk Hills 3 miles to the south, via pipeline, where it would be used to facilitate carbon dioxide enhanced oil recovery (CO_2-EOR).

Process water would be supplied by the Buena Vista Water Storage District (BVWSD) and would be delivered from a new well field that would be installed 15 miles northwest of the project site. The summary of Proposed Water Transfer Terms (HECA 2012b, Appendix N) shows BVWSD would supply HECA with up to 7,500 acre-feet per year (AF/y) of water with a concentration of total dissolved solids (TDS) ranging from 1,000 to 4,000 mg/L. The use of this water supply would allow the BVWSD to implement one of the primary components of their Brackish Groundwater Remediation Plan (HECA 2012b). HECA will fund development of this component of BVWSD's program and turn it over to BVWSD to own and operate.

Water for construction and potable uses would be supplied by the WKWD located south of the project. Seven miles of pipeline would be constructed to deliver water from the district. Horizontal directional drilling (HDD) would be necessary to route the pipeline beneath the Outlet Canal, the Kern River Flood Control Channel (KRFCC), and the California Aqueduct (HECA 2012b).

Project construction milestones have been affected by delays in the application process. The projected milestones below are based upon an approximately 7-month delay from those projected proposed by the applicant in the May 2, 2012, AFC (Vol. I, page 2-11):

- Commencement of preconstruction, and construction activities: January 2014
- Completion of construction: September 2017
- Commencement of commercial operation of HECA: April 2018

Project Water Supply

West Kern Water District, Construction and Domestic Supply

Potable water needs during operation would be supplied by groundwater from WKWD. Average potable water use would be approximately 1,800 gallons per day (gpd), but could be as high as 2,750 gpd. The average potable water demand would be equal to 2.0 AF/y. The project would provide potable water for up to 200 full-time employees (HECA 2012b).

Construction water would also be supplied by WKWD by pipeline and truck. Average construction water use would be approximately 5,340 gpd and maximum use would be approximately 12,000 gpd. Total use over the 42 months of construction would be about 46 AF, about 12 AF/y (HECA 2012b).

Buena Vista Water Storage District, Industrial Supply

The proposed project would use an annual average of about 6.6 million gallons of groundwater per day and up to 7.4 million gallons per day (gpd) in summer for industrial purposes. This is equivalent to an average water use of 7,420 acre-feet per year (AF/y). BVWSD would supply up to 7,500 AF/y to HECA as detailed in the will-serve letter (HECA 2012b). About 0.5 million gpd of the supply would be necessary to create high-quality demineralized water for a gasifier and boiler make-up water. All of the proposed industrial supply water would be supplied by the BVWSD and treated as necessary by HECA.

The projected annual use by HECA is presented in **Water Table 2** below.

Water Table 2
Expected Industrial Use

	Supplier	Average Use Rate (gpd)	Average Use Rate (AF/y)	Maximum Use Rate (gpd)
Industrial Water (total)	BVWSD	6,624,000	7,420	7,416,000

Source: HECA 2012b

Beneath the proposed well field, TDS concentrations in well water samples range from 1,000 to 4,000 mg/L. The TDS concentrations in groundwater reportedly decrease toward the east, where groundwater for agricultural supply increases. West of the proposed well field, groundwater is believed to be relatively high in salinity and of low quality due to the influence of alluvium originating from the Coast Range marine rocks. The BVWSD therefore envisions extraction wells located near the western district boundary to intercept the high TDS groundwater originating in the Coast Range alluvium while inducing the westward migration of relatively low TDS groundwater from the east. The desired outcome of well field operation is therefore an overall improvement in groundwater quality beneath BVWSD areas located east of the well field.

BVWSD does not currently have the capacity for the proposed groundwater pumping or conveyance facilities necessary to implement the BGRP and would construct pumping and conveyance facilities specifically for HECA. No other potential users of this supply are identified in BVWSD's Final Environmental Impact Report (FEIR) for the BGRP (BVW 2010a). The purpose of the BGRP program would be to remediate shallow perched and brackish groundwater that has adversely impacted plant growth and crop yield within the district. The program would seek to operate two strategic pump zones called Target Area A (north of 7^{th} Standard Road) and Target Area B (mostly south of 7^{th} Standard Road), as shown on **Water Figure 2**. The portion of the district south of 7th Standard Road is underlain by groundwater having total dissolved solids (TDS) concentrations ranging from 700 to 4,000 mg/L (Target Area B), whereas areas to the north are underlain by ground water with concentrations ranging from 1,000 to 5,000 mg/L (Target Area A). Combined extraction of the BGRP could total up to 12,000 AFY (BVW 2010a).

The BGRP Target Area A would include 40 shallow, low-flow extraction wells in a grid pattern in the northern half of the district where water stands at two to ten feet below the ground surface. The goal in this target area is to lower the water table and improve cropland productivity. The FEIR identifies no potential users for this water. This water is identified as having TDS concentrations between 1,000 and 5,000 mg/L (BVW 2010a). Though not a proposed source of groundwater for HECA, Target Area A is described as a source of brackish water that may supply up to 4,500 AF/y to the BGRP.

The HECA project would receive water from Target Area B. Target Area B is located along the west-central edge of the district. Up to ten wells are planned to extract groundwater from between 200 to 700 feet below the ground surface (the zone of brackish water with TDS concentrations between 700 and 4,000 mg/L). The water quality produced by the extraction wells is expected to be a mix of relatively high TDS water originating west of the well field and low TDS water originating east of the well field. The strategic locations of the proposed wells are intended to reduce the lateral recharge from the west from moving further eastward into the district (BVW 2010a).

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

This section provides an evaluation of the expected direct, indirect, and cumulative impacts to soil and water resources that could be caused by construction, operation, and maintenance of HECA. Staff's analysis consists of a description of the potentially significant impact, gathering data related to construction and operation of the project, then reaching a conclusion to determine whether or not the project presents a potentially significant impact. If staff determines there is a significant impact, then staff evaluates the applicants' proposed mitigation for sufficiency and staff may or may not recommend additional or entirely different mitigation measures that are potentially more effective than those proposed by the applicant. Mitigation is designed to reduce the effects of potentially significant HECA impacts to a level that is less than significant. The determination of significance for potential impacts to soil and water resources is discussed below.

METHOD FOR DETERMINING SIGNIFICANCE OF IMPACTS

This document analyzes the project's impacts pursuant to both the National Environmental Policy Act (NEPA) and CEQA. The two statutes are similar in their requirements concerning analysis of a project's impacts. Therefore, unless otherwise noted, staff's use of, and reference to, CEQA criteria and guidelines also encompasses and satisfies NEPA requirements for this environmental document.

This section provides an evaluation of the expected direct, indirect, and cumulative impacts to water supply that would be caused by construction, operation, and maintenance of the project. Staff's analysis of potential impacts consists of a description of the potential effect, an analysis of the relevant facts, and application of the threshold criteria for significance to the facts. If mitigation is warranted, staff provides a summary of the applicant's proposed mitigation and a discussion of the adequacy of the proposed mitigation. If necessary, staff presents additional or alternative mitigation measures and refers to specific conditions of certification related to a potential impact and the required mitigation. Mitigation is designed to reduce the effects of potential significant project impacts to a level that is less than significant.

Staff evaluated the potential of the project's proposed water use to cause a substantial depletion or degradation of groundwater resources, including beneficial uses. Staff considered compliance with the LORS and policies presented in **Water Table 1** and whether there would be a significant California Environmental Quality Act (CEQA) impact. Compliance with LORS and policies includes the Energy Commission's and

State Water Resources Control Board's policy against using freshwater for power plant cooling unless other sources or other methods of cooling would be environmentally undesirable or economically unsound. A discussion of the applicable policies is contained in the "Water Use LORS and State Policy Guidance" subsection of this PSA section.

To evaluate if significant CEQA impacts to water resources would occur, the following criteria were used. Where a potentially significant impact was identified, staff or the applicant proposed mitigation to reduce the impacts to less than significant or reduce to the extent possible.

a. Would the project substantially deplete groundwater supplies or interfere substantially with groundwater recharge such that there would be a net deficit in aquifer volume (deplete groundwater storage).
b. Would the project contribute to any lowering of groundwater levels and impact the production rate of pre-existing wells to a level which would not support existing or planned uses for which permits have been granted or cause physical damage to the well?
c. Would the project contribute to any lowering of the groundwater levels such that protected species or habitats are affected?
d. Would the project cause substantial degradation to surface water or groundwater quality?

STAFF ANALYSIS OF INDUSTRIAL WATER SUPPLY

Applicant Groundwater-Flow Model Construction

The applicant utilized a three-dimensional numerical groundwater-flow model to simulate well interference (drawdown) and delineate the pumping zone of influence (ZOI). The model is based on MODFLOW (McDonald&Harbaugh1988); MODFLOW is a widely accepted model code that has been verified to produce numerically stable solutions (Anderson&Woessner1991).

Numerical groundwater-flow modeling involves first developing a conceptual model of the physical system and then applying a mathematical model to quantitatively represent it. The conceptual model is a clear, qualitative description of the natural system and its operation including water sources (recharge), flow directions, and groundwater sinks (discharge). The mathematical model utilizes equations to simulate the physical processes described by the conceptual model. The potential complexity of processes and variety of boundary conditions typically require numerical procedures to determine an approximate solution to the mathematical groundwater-flow equations.

In applying models to real world groundwater-flow systems, errors can potentially arise from the following sources:

- Numerical deficiencies from errors associated with the equation solvers. These errors introduce problems with computational accuracy and precision.

- Conceptual deficiencies (i.e., erroneous basin geometry, incorrect boundary conditions, neglecting important processes, including inappropriate processes, and so forth).
- Inadequate representation of water transmitting and storage properties (parameterization) and incorrectly specified stresses (the magnitude, timing, and spatial distribution of water inflow [recharge] and outflow [pumpage]).

The most common modeling errors are attributed to conceptual deficiencies and inadequate/poorly defined parameterization and stresses. Key model assumptions and construction specifics are listed below, followed by modifications staff deemed necessary to improve the model's representation of the real-world groundwater system.

- The model simulates a 25-year period. Each year comprises two stress periods. One stress period is 75 days in length, and simulates the two and one-half month period that recharge occurs due to seepage from irrigation ditches and the canal system, and the second stress period is 290 days in length to simulate the remainder of the year when recharge does not occur. Pumpage is simulated during both stress periods to represent continuous pumpage 365 days of the year. These stress periods sufficiently represent temporal changes in water use within the model area as a result of the proposed project. However, staff disagreed with simulating recharge in this model application and provide their reasons in the section "Applicant's Modeling Approach."
- The model represents a 10,000 square mile area, which is considerably larger than the proposed project area and intended to minimize boundary effects on the simulation results. Head-dependent flow conditions specified at its boundaries are employed to further minimize boundary effects and approximate an aquifer of infinite extent. Staff concluded this approach is too generalized for this application, and the results likely minimize water level changes due to project pumping. Staff recommended changes to the model are discussed below in "Staff Recommended Changes to Model Construction."
- The model is a rectangular grid appropriately utilizing cell sizes that range from 20 x 20 feet in the vicinity of the proposed pumping wells to 2,500 x 2,500 feet at the most distant model boundaries. By definition, the simulated groundwater level changes in each model cell represent the average groundwater level change within the area represented by the cell.
- In the vertical direction, three model layers represent the aquifer. The simulated water table and pumping wells are located in layer 1 (270 feet thick saturated interval), and deeper aquifer conditions are represented by layer 2 (300 feet thick saturated interval) and layer 3 (2,000 feet thick saturated interval). The approach assumes that the constant parameter values specified for each layer adequately represent vertical variations in water transmitting and storage properties.
- The modeled hydraulic conductivity value is 42.8 ft/d and reasonably close to the median effective conductivity value of 47.6 ft/d determined from 7 aquifer tests reported by URS (2010a). Horizontal hydraulic conductivity is therefore likely appropriately specified in the model. The modeled vertical conductivity is assumed to be 30 times smaller than the horizontal conductivity. No measured vertical conductivity values are available from which to confirm this value, nor is

geologic data summarized and discussed to relate the assumed vertical conductivity and observed vertical variations in relatively coarse- and fine-grained deposits that occur within the modeled depth intervals that range from 270 to 2,000 feet in thickness. For example, a previous San Joaquin Valley modeling effort suggested that fine-grained deposits could reduce the effective vertical conductivity represented by relatively thick model layers. Hence, the effective vertical hydraulic conductivity may be lower than represented in the model. Staff therefore recommended a more complete assessment to include potential uncertainty in model results due to the assumed vertical conductivity. The recommended analysis is discussed below in the subsequent section “Staff Recommended Changes to Model Construction.”

- The modeled specific yield and specific storage values are 0.18 and $5.5x10^{-5}$ per ft, respectively. However, aquifer test results reported by URS (2010a) indicate a geometric mean storativity of 0.007. The actual water level decrease due to simulated pumpage from the model layer 1 depth interval may therefore be substantially greater than modeled. Staff recommended a more complete assessment to include potential uncertainty due to the specified storage parameter. The recommended analysis is discussed below in the subsequent section “Staff Recommended Changes to Model Construction.”
- The model simulations are assumed to converge when the residuals in hydraulic head and volumetric fluxes meet the user’s specified criteria. The recommended error criterion for groundwater levels should be one to two orders of magnitude smaller than the accuracy level desired, and the error in the water balance is ideally less than 0.1 percent (Anderson&Woessner1991). The model simulations reviewed by staff appropriately employed a water level closure criterion of 0.01-foot and resulted in typical mass balance errors less than 0.01 percent.
- Groundwater pumpage is the sole discharge simulated from the aquifer. The model appropriately simulates a continuous annual pumping rate of 7,500 AF/yr distributed evenly between three wells. All of the pumpage occurs in model layer 1.
- Recharge is the primary simulated inflow to the aquifer. Recharge is simulated to “off-set project pumping”, and 7,500 AF/yr of recharge is simulated as occurring within 18,750 acres around the extraction wells. The simulated recharge is assumed to occur during a 75-day period each year. Staff disagreed with the need to simulate recharge in this model application, and the recommended changes to simulated recharge are discussed below in the subsequent section “Review of Applicant’s Modeling Approach.”

Staff Recommended Changes to Model Construction

Staff disagrees with several of the hydrologic conditions and assumptions utilized to construct the groundwater-flow model as follows:

- The model domain ignores the contact between water-bearing alluvium and the essentially non-water bearing marine rocks of the Coast Ranges. The contact between alluvium and rock is located approximately six miles west of the proposed well field. Accordingly, a zero- or no-flow boundary is needed approximately 6 miles west of the well field.

- Hydrogeologic subbasin boundaries are reportedly located about 5 to almost 17 miles north and south of the proposed well field, respectively. These boundaries are defined by structural highs due to folding or faulting, and may isolate, at least partially, the hydrogeologic subbasin in which the simulated well field is located (the Buttonwillow subbasin) from other parts of the southern San Joaquin Valley groundwater basin (URS2009). Hence, the three remaining model boundaries could conceivably also be re-located and changed to no-flow boundaries to correspond to the Buttonwillow subbasin boundaries.
- Head-dependent flow conditions were reportedly specified at the boundaries of the active model domain to minimize boundary effects and approximate an aquifer of infinite extent. However, the model files provided by the applicant (Confidential May 12, 2010 transmittal of model files from Liz Elliot, URS) specified head-dependent flow conditions in model layer 1 only. Employing head-dependent flow conditions can be an acceptable approach for minimizing boundary effects, however there must be a physical reason for utilizing different boundary conditions in the other model layers. Furthermore, because head-dependent boundaries can add or remove significant quantities of groundwater to or from the model domain, the results should be inspected to confirm boundary conditions do not significantly influence model results.
- Specific yield is a measure of the volume of water drained from saturated unconfined aquifer material under the force of gravity per unit surface area and unit change in water table elevation. The applicant assumed the 270-feet thick pumped aquifer simulated by the model is unconfined, and the model assigned a specific yield value of 0.18 to pumped aquifer represented by model layer 1. The aquifer test results reported by URS (2010a) suggest however that the pumped aquifer is not unconfined but rather may be semi-confined.

  The URS (2010a) aquifer tests were conducted on wells screened at depths corresponding to model layer 1 and the upper portion of model layer 2. The aquifer test results indicate a geometric mean storativity of 0.007. Storativity is a measure of the volume of water released by compression of the aquifer structure and expansion of the water in response to the decline in pressure in a confined or semi-confined aquifer. The storativity of 0.007 is about 25 times smaller than the modeled specific yield (0.18), and is indicative of semi-confined aquifer conditions. The model therefore inappropriately represents the entire upper 270 feet of saturated sediment as an unconfined aquifer, and as a result likely under-estimates the water level decline caused by groundwater extractions that occur at depths below the water table.

  Additional information is needed to identify the thickness of the unconfined water table aquifer, which based on URS (2010a) aquifer test results occurs at depths less than 270 feet. This information can be utilized to separate the existing model layer 1 into two layers. The new layer 1, which will be less than 270 feet thick, can represent the upper unconfined depth interval of the aquifer and utilize the specific yield value of 0.18. The new, underlying layer 2 can be assigned the remaining thickness of the original layer 1 and represents the semi-confined aquifer characterized by the reported storativity value of 0.007.

- In the absence of reliable information to complete these necessary model layer refinements, a simpler approach assigns the reported storativity (0.007) to the entire depth interval represented by layer 1. This simpler approach is limited because less water is available from storage than if the unconfined portion of the aquifer were explicitly modeled. Hence, the model results from this simpler approach will likely over-estimate the water level decline caused by groundwater extractions and therefore provides conservative estimates of groundwater impacts. In the absence of reliable information to delineate the unconfined and confined portions of the aquifer, the simpler approach is therefore preferred.
- The model assumes vertical conductivity is 30 times smaller than horizontal conductivity, which may be too low relative to actual conditions and model layer thicknesses. URS (2009) tested model sensitivity to vertical conductivity and reported that the extent of simulated drawdown increases as the modeled vertical conductivity decreases. However, the modeled vertical conductivity is the net effect of all the sediment beds within the entire depth interval represented by the model layer. Aquifer testing and model calibration results reported by Belitz and others (1993) for Coast Range and Sierran alluvium suggest that intermittent clay deposits can reduce the modeled vertical conductivity relative to horizontal conductivity by a factor of more than 1,000. Unless data from boreholes located in the well field and adjacent areas show an absence of clay deposits within the relatively thick depth intervals represented by the model layers, staff recommends addressing the potential influence of fine-grained beds on the modeled vertical conductivity. In the absence of more detailed information, staff recommends revising the anisotropy[1] in the model to 1,000 to consider uncertainty in vertical conductivity across the relatively thick model layers.

Review of Applicant's Modeling Approach

The applicant appropriately employed "superposition" to simulate the proposed well field operation. Superposition solves a complex problem using an incremental and additive approach. The principal constraint to using superposition is that the mathematical equation describing the groundwater problem – both within the model domain and the boundary conditions – must be linear.[2] In this application, the complex problem is the prediction of groundwater level changes in the basin, and superposition is employed to determine the incremental drawdown due solely to pumping for proposed power plant water use.

[1] Anisotropy in hydrogeologic terms refers to a matrix of earth materials with differing hydraulic conductivity in different directions. It is typically measured or compared in the horizontal and vertical directions and expressed as a ratio of horizontal to vertical conductivity, or H:V. It is an important parameter for estimation of effects on groundwater flow because the presence of fine grained deposits like clay in sedimentary deposits can significantly reduce the rate of vertical flow compared to horizontal flow in sand and gravel deposits.

[2] Some of the mathematical equations that describe groundwater flow are linear – others are not. The equations utilized to describe unconfined groundwater-flow are not linear, but when the saturated interval is thick relative to the water level changes considered it is common practice to assume the unconfined system behaves approximately linearly. As a rule of thumb, superposition can be applied if the basin-wide drawdown of the unconfined aquifer is 10 percent or less of the saturated interval (Reilly&Others1987).

In practice, in a superposition model, the specified initial head distribution and boundary conditions are defined in terms of relative changes rather than actual observed values. Initial heads within the model domain are specified as all being equal. Fixed-head boundaries use water levels specified equal to initial groundwater levels so that the initial hydraulic gradient along the boundary is zero. Constant-flux boundaries are specified as no-flow (zero-flux) boundaries corresponding to no net change in flow. Specified pumpage represents the incremental increase in the pumping rate relative to existing or background pumpage, and specified recharge represents the incremental increase in recharge relative to existing or background recharge rates.

In applying superposition to analyze the proposed well field, the applicant simulated a pumping rate of 7,500 AF/yr. The simulated pumping rate represents an incremental increase in groundwater extraction above background groundwater production within the Buttonwillow Service Area. Similarly, the applicant simulated a recharge rate of 7,500 AF/y to represent an incremental increase in recharge within the Buttonwillow Service Area. The simulated water levels and fluxes therefore represent the incremental changes in groundwater conditions resulting from these increases in pumping and recharge. The model results are relative to background groundwater conditions, and actual changes would be the combined sum of the incremental changes due to the project and background conditions.

Simulated recharge (7,500 AF/y) applied by the applicant represents an incremental increase in recharge above typical annual recharge rates in the Buttonwillow Service Area. Typically, recharge rates in the project setting are supplied by applied water and/or seepage losses from drainage ditches and canals. Accordingly, the 7,500 AF/y increase in recharge must correspond to an increase in water deliveries and applied water, a 7,500 AF/y reduction in existing annual water consumption, or a similar decrease in annual drainage discharge. An increase in water deliveries in the Buttonwillow Service Area must correspond with a decrease in water deliveries in another part of the BVWSD. Furthermore, the applicant's analysis does not consider potential downstream impacts resulting from the reduction in ditch and canal flows that would occur if these sources provided the necessary increase in seepage. Because the source of the "new" water for the recharge increase was not identified as part of the project description, staff concluded recharge is incorrectly specified in the model.

Model Results

Well Interference

Consumptive use of water from wells within a groundwater basin may contribute to lower water levels at other well locations (well interference). The groundwater-flow model was employed to simulate the water level drawdown at existing wells due to pumping from the proposed well field.

Well interference is considered significant if water level changes in and around an existing well appreciably affects its ability to meet its intended use. Reductions in well yield can occur as the static or pumping water levels decrease. The maximum theoretical well yield can be defined as the maximum pumping rate supplied by a well without lowering the water level below the pump intake (Freeze&Cherry1979). Typically, pump intakes are located near the top of the screened interval because it is desirable to keep the well screen submerged as this minimizes chemical clogging and physical deterioration of the well screen (Driscoll1995).

Water Table 3 summarizes available well completion data from well driller reports (well logs) and water level data records obtained from the California Department of Water Resources. On average, wells are almost 450 feet deep and the top of the well screens are located almost 200 feet below land surface. See **Water Figure 3** for general locations of wells.

Water Table 3
Available Well Completion Data from Well Driller Reports (Well Logs)
And Water Level Data Records

Map number	Well Depth	Top of perforation	Bottom of perforation	Water level (amsl)	Date
	feet below land surface				
1	450	240	450	--	--
2	340	276	340	--	--
3	256			--	--
4	204	168	204	--	--
5	553	203	553	--	--
6	460	200	460	--	--
7	201	174	198	--	--
8	300	120	300	--	--
9	400	175	400	--	--
10	340	78	340	--	--
11	515	275	515	--	--
12	620	410	610	--	--
13	532	312	532	--	--
14	455	414	455	--	--
15	300	108	300	--	--
16	600	150	600	--	--
17	335	150	335	--	--
18	300	90	294	--	--
19				224	2/8/1961
20	274			228	2/8/1961
21	402			223	2/8/1961
22				222	2/8/1961
23	725			141	2/8/1961
24				221	2/8/1961
25				225	2/8/1961
26				224	2/8/1961
27	400			221	2/8/1961
28	515	212	515	215	2/8/1961
29	526			215	2/8/1961
30				222	2/8/1961
31	516			216	2/8/1961
32				219	2/8/1961
33	433			221	2/9/1961
34	800			197	2/9/1961
35	600			214	2/9/1961
36	700			168	2/9/1961
37	525			177	2/9/1961

Map number	Well Depth	Top of perforation	Bottom of perforation	Water level (amsl)	Date
	feet below land surface				
38				223	2/9/1961
39	606	150	606	226	2/9/1961
40	304			219	2/9/1961
41	402			197	2/9/1961
42				202	2/18/1961
43	291			169	2/18/1961
44	324	102	318	213	2/18/1961
45	446			206	2/18/1961
46	402			206	2/18/1961
47	670			211	2/18/1961
48				221	2/18/1961
49	450	150	450	242	5/5/1986
50	364			211	9/23/2002
51				208	9/23/2002
52				243	9/1/2006
53				234	1/7/2008
54				235	8/26/2008
55				214	8/26/2008
56				232	8/3/2009
57				234	8/3/2009
58				222	8/3/2009
59				237	9/1/2009
60				236	9/1/2009
61				235	9/1/2009
62				243	9/1/2009
Average	446	198	418	207	
Median	440	174	450	206	

Average and median water levels calculated from 2009-2010 data only.
Map number refers to **WATER Figure 3**.

Drawdown Impacts

Staff analyzed the potential for water level declines that could result in wells that neighbor the proposed project wells. Staff determined that a predicted 15-foot drawdown would constitute a significant impact. As shown in the "**Increased Cost of Pumping**" section below, a 15-foot decline could result in a 25% increase in the cost of pumping. The analysis below explains the specific treatment and potential impacts to local receptors. Staff utilized the applicant's model to simulate projected water level changes owing to 25-years of project pumping. Simulated drawdown contours resulting from use of the applicant's model are mapped in **Water Figure 4**, and simulated drawdown at select well locations is summarized in **Water Table 3** (see **Water Figure 3** for well locations corresponding to the map numbers listed in **Water Table 3**). The simulated drawdown values using the applicant's model ranged from -0.7 to 12.0 feet; drawdown less than zero indicates that as a result of simulated recharge the model predicts water levels will increase during the 25-year simulation period.

The simulated drawdown contours from staff's modified model (no-flow boundary added and no recharge) are shown in **Water Figure 5.** The results indicate greater drawdown over a generally larger area than simulated by the applicant's model. The simulated drawdown in the staff modified model ranged from 2.2 to 15.8 feet, representing an average increase of more than 3 feet relative to the applicant's model. The maximum drawdown (15.8 feet) exceeds the well interference threshold by almost 1 foot at one well (the well is located within the boundaries of the proposed well field area and identified by Map ID 6 in **Water Figure 3**).

Simulated drawdown in **Water Table 4** represents the water level changes due solely to project well field operation. Actual water level changes and volumetric fluxes will be the net result of multiple recharge and discharge processes occurring in the basin and can therefore be quite different from the model results. For example, the simulated drawdown in the well identified by Map ID 50 is 3.8 feet, indicating that 25-years after well field start-up the water level in this well will be 3.8 feet lower than without the well field (no project conditions).

Water Table 4
Drawdown At Select Well Locations Simulated by Applicant's Model And Three Modified Models

Map number	Applicant's model	Modified model BC and recharge	Modified model with reduced storativity	Modified model with reduced storativity and vertical conductivity
	simulated drawdown, in feet			
1	3.1	4.1	5.6	11.3
2	0.9	4.1	5.5	11.3
3	-0.4	4.7	6.1	13.1
4	0.1	2.4	3.9	5.4
5	-0.4	3.9	5.3	10.7
6	6.8	15.8	17.3	34.2
7	-0.7	7.7	9.1	21.3
8	0.1	12.0	13.5	29.7
9	1.0	7.6	9.1	21.0
10	-0.6	6.8	8.3	19.0
11	-0.2	5.4	6.9	15.3
12	-0.1	3.6	5.1	8.8
13	5.5	5.3	6.8	15.0
14	0.1	4.6	6.1	12.9
15	0.7	4.2	5.6	11.4
16	0.9	4.3	5.8	11.9
17	0.5	4.0	5.5	10.9
18	0.3	3.9	5.4	10.5
19	12.0	3.1	4.5	7.6
20	8.1	4.4	5.8	12.3
21	3.9	4.4	5.8	12.2
22	2.1	3.9	5.3	10.4
23	1.3	2.2	3.5	5.1
24	-0.6	2.6	3.9	6.1
25	-0.3	3.2	4.6	8.0
26	-0.5	3.2	4.6	8.1
27	-0.5	3.2	4.6	8.1
28	-0.4	4.0	5.4	10.8

Map number	Applicant's model	Modified model BC and recharge	Modified model with reduced storativity	Modified model with reduced storativity and vertical conductivity
	simulated drawdown, in feet			
29	-0.5	5.3	6.7	15.1
30	-0.1	3.0	4.4	7.4
31	-0.1	3.4	4.9	8.9
32	2.9	3.3	4.7	8.4
33	0.3	2.5	3.9	5.9
34	0.3	2.6	4.0	6.1
35	0.7	2.7	4.1	6.2
36	0.2	2.8	4.2	6.7
37	0.1	3.5	4.9	8.9
38	0.7	3.3	4.7	8.3
39	-0.4	6.6	8.1	18.6
40	-0.4	10.7	12.2	27.4
41	-0.2	2.3	3.6	5.1
42	2.8	2.4	3.8	5.6
43	0.2	4.0	5.4	10.9
44	0.7	4.4	5.9	12.1
45	2.6	2.3	3.7	5.4
46	-0.2	2.3	3.7	5.3
47	-0.1	2.6	4.0	6.0
48	0.5	2.4	3.8	5.5
49	-0.4	6.7	8.2	19.0
50	3.8	4.0	5.5	11.0
51	-0.4	9.3	10.8	24.9
52	0.5	3.8	5.2	10.0
53	1.5	4.5	5.9	12.5
54	0.8	4.6	6.1	12.9
55	0.4	4.6	6.1	12.9
56	0.1	4.0	5.5	10.9
57	-0.3	3.7	5.1	9.6
58	-0.3	6.1	7.6	17.3
59	0.6	3.4	4.8	8.6
60	0.6	3.2	4.7	8.1
61	-0.5	3.3	4.7	8.2
62	0.5	4.0	5.5	10.8
Maximum	12.0	15.8	17.3	34.2
Minimum	-0.7	2.2	3.5	5.1

Staff performed additional model testing which showed simulated drawdown extracted by the proposed well field is sensitive to assumed aquifer conditions. Utilizing the reported representative storativity (0.007) increased the magnitude and extent of simulated drawdown (**Water Figure 6**), and on average simulated drawdown increased by almost five feet relative to the applicant's model results (**Water Table 4**). The maximum simulated drawdown increased from 12.0 to 17.3 feet, but the 15-feet threshold was exceeded at only one location.

Increasing the applicant's simulated anisotropy from 30 to 1,000 further increased the magnitude and extent of simulated drawdown (**Water Figure 7)**. On average, simulated drawdown increased by almost 11 feet relative to the applicant's model (**Water Table 4**). The maximum simulated drawdown increased from 12.0 to 34.2 feet, and the 15-feet threshold was exceeded at 13 locations (an increase of 12 wells).

Increased Cost of Pumping

If the total hydraulic head in neighboring domestic wells is lowered, then well yield would be reduced and an increase in pumping cost is expected. Pumping costs can be estimated with the following equation:

$C = 0.746Qhc / 3960e_pe_m$

Where

C = total cost per hour
Q = pump rate (gpm)
h = total head (ft)
c = cost per kWh
e_p= pump efficiency
e_m = motor efficiency

Staff estimated potential increases in pump cost incurred by an owner (pumping 10 gpm) experiencing a 15-foot decline in water levels using a pump (e_p) and motor (e_m) efficiency of 80-percent (0.80) and a cost for energy equal to $0.16 per kWh. Using these values, pumping costs could increase by about 25 percent. Staff believes that the decrease in well yield that would result in a 25 percent increase in pumping costs is a significant impact. Staff proposes Condition of Certification **WATER-1** which would require the monitoring of local domestic wells to determine if project-induced water level decline is observed. Staff also proposes Condition of Certification **WATER-2** which provides a method for calculating the reimbursement necessary to offset costs from decreased well yield. This condition utilizes an equation similar to Equation 3 above, but applied to a particular well under its own set of unique circumstances.

Groundwater Quality Impacts

Staff could find no specific provision or policy used by BVWSD to identify what constitutes a water quality impact from pumping such as that proposed for the project. Staff used the RWQCB Basin Plan beneficial uses for groundwater designated in this area and considered whether the pumping would degrade water quality such that it could not be used for the identified beneficial uses. The suitability of water for use as irrigation water becomes marginal where TDS reaches concentrations of 2,000 ppm. As described by Dr. L.D. Doneen in 1954 (Doneen, 1954), reiterated by DWR in various Water Quality Investigations, and promulgated in the Water Control Plan for the Tulare Lake Basin (RWQCB, 2004), water that exceeds electrical conductivity levels of 3,000 micromhos per centimeter and TDS levels of 2,000 mg/L has limited suitability for irrigation use (**Water Table 5**).

Water Table 5
Irrigation Water Suitabilities

Irrigation use	Electrical Conductivity (mhos/cm @ 25°C)	TDS (mg/L)
Suitable/Class I	0 - 1,500	< 700
Marginal/Class II	1,500 - 3,000	700 - 2,000
Inferior/Class III	> 3,000	> 2,000

Source: Doneen, 1954; Tulare Lake Basin Plan, RWQCB, 2004

The HECA project proposes to receive groundwater from BGRP Target Area B. The water underlying Target Area B contains TDS at concentrations between 1,000 mg/L and 4,000 mg/L. The will-serve letter signed by Hydrogen Energy and BVWSD states that the water supply for HECA would vary between 1,000 mg/L to 4,000 mg/L, with an average of 2,000 mg/L. This water is described by BVWSD as having few uses and also as being the cause of low crop yield and low crop quality within the district. However, specific studies of crops of pistachios from western San Joaquin Valley indicate no adverse impacts to crop or yield at salinities even greater than 3,000 mg/L TDS (Fergusson et al., 2002). This same claim is made by HECA intervenor and residents, Association of Irritated Residents (AIR), that states the water proposed for use by the project is suitable for pistachios (AIRe). They believe groundwater of this quality should be protected for such agricultural use.

Staff used a TDS concentration of 2,000 mg/L as a threshold for comparison with background or baseline conditions where the primary beneficial use is irrigation. Where project pumping could cause TDS concentrations to exceed 2,000 mg/L staff believes there is potential for a significant impact. See staff's discussion of project-related water quality changes below. Where background TDS concentration is greater than 2,000 mg/L staff considered whether the groundwater may reasonably be considered a potential drinking water supply that should be protected in accordance with SWRCB drinking water policy. This policy requires, among other things, that a water source with TDS concentrations less than 3,000 mg/L should be protected as a potential drinking water supply. Where project pumping would cause TDS concentration increases beyond 2,000 mg/L staff concludes this would also be a significant impact for potential use as a drinking water supply. Where background TDS concentrations are greater than 3,000 mg/L staff believes that pumping would not impact reasonable beneficial uses.

In the Buttonwillow Service Area, the pumped groundwater zone as indicated by the average depth to the top of the perforations in water supply wells is about 200 feet below land surface (**Water Table 2**). Well water sample results from the period 1961-2006 and composite 1970-2007 TDS concentrations contours (BVWSD2009) for deep wells are mapped in **Water Figure 8**. Five deep wells have posted values that are greater than the TDS concentrations depicted by the contours. Four of these five wells are located in the central part of the Buttonwillow Service Area or to the east and in the Semitropic Water Storage District. Over half of the remaining wells have posted TDS concentrations that are less than the values depicted by the contours. The remaining posted well concentrations generally agree with the contours. There doesn't appear to be an identifiable spatial pattern in the differences between well concentrations and the reported contours, and the contours may be considered an unbiased but only approximate representation of the spatial variability in groundwater quality.

Well water sample results and summer 2001 TDS concentrations contours (BVWSD2009) for deep wells are mapped in **Water Figure 9**. Most well water samples had TDS concentrations either less than or similar to the TDS concentrations contours. The sample results generally agree with the contours in the area south of Highway 58 where TDS concentrations are relatively low. In the central part of the Buttonwillow Service Area and near the proposed well field, all but two of the well water samples have lower TDS concentrations than indicated by the contour values (the two exceptions are the 4,300 mg/L sample from the well located on the 2,000 mg/L contour, and 1,400 mg/L sample from the well located east of the 1,000 mg/L contour). In the northern part of the Buttonwillow Service area, there appears to be little agreement between well water sample results and TDS concentrations contours.

In the northern part of the Buttonwillow Service Area, shallow “perched”[3] groundwater and elevated TDS concentrations have reportedly adversely impacted plant growth and crop yields. **Water Figure 10** shows 2008 TDS concentrations contours reported by BVWSD (2009) and the results from shallow well-water samples collected in the northerly area. The posted well sample results are generally higher than the TDS concentrations depicted by the contours. One exception is the DWR data value of 537 mg/L from a well of unknown depth located near the intersection of I-5 and Highway 46. In the southern half of the area represented by the contours, the posted values are either consistent or lower than the contours. The three lower posted values are located between the West Side and Main Drain canals and range from 389 to 828 mg/L, whereas the contours indicate concentrations range from between 2,000 and 4,000 mg/L. Two of the three samples (389 and 828 mg/L) are from wells of unknown depth, and therefore may represent deep groundwater. These samples were collected and analyzed more than 50-years ago (DWR1961), and present-day TDS concentrations at these locations may be different than at the time of sampling.

In 1986, the USGS collected TDS and stable isotope data (deuterium and oxygen-18) which indicated greater TDS concentrations in the northern area likely reflect concentration increases due to evaporation from the shallow water table. The evaporation process adds kinetic separation to the deuterium and oxygen-18 species causing increased enrichment resulting in a characteristic evaporative trend line. **Water Figure 11** shows the deuterium and oxygen-18 compositions (expressed in the “δ” notation) for the 1986 USGS sample locations shown in **Water Figure 12** (the deep well samples plotted in **Water Figure 11** were discussed previously under the heading “TDS Concentrations in the “Deep” Pumped Groundwater Zone”). The shallow well data points plot on an evaporative trend line with a shallower slope than the meteoric water line discussed in Craig (1961), and the posted TDS concentrations indicate the more isotopically enriched Buttonwillow Service Area water samples generally have the greater TDS concentrations.

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[3] A perched water-table is a special case of an unconfined aquifer whereby the perched groundwater is separated from the underlying main groundwater system by low permeability strata and an underlying unsaturated zone. In the Buttonwillow Service Area, it is uncertain whether an unsaturated zone exists between the shallow water table and main (pumped) groundwater zone.

The evaporative trend line is described by the equation $\delta D = 4.6 \times \delta^{18}O - 31.5$ and is comparable with previous isotope studies from the San Joaquin Valley (Deverel& Fujii1988; Deverel&Gallanthine1989) and other arid areas (e.g. Gat&Isaar1974; Fontes&Gonfiantini1967). **Water Figure 13** shows that correlation between TDS concentrations and isotope composition ($\delta^{18}O$) and calculations indicate the correlation is statistically significantly ($r^2 = 0.47$, $p < 0.05$). Deverel&Fujii1988 and Deverel&Gallanthine1989 found similar correlations between groundwater salinity and isotopic enrichment in the San Joaquin Valley.

Evaporation from the water table is likely ongoing in parts of the Buttonwillow Service Area where shallow groundwater conditions are prevalent. Moreover, the shallow geologic deposits in the area are fine-grained and hydraulic conductivity is low. In the area where the depth to groundwater is ten feet or less, the soils range in texture from clay to clay loam (USDANRDC2008). These soil textures are similar to shallow groundwater areas in the San Joaquin Valley described by Fio&Deverel1991 and Deverel&Fio1991, where they determined groundwater velocities are low (ten feet per year or less). Hence, we expect present-day TDS concentrations to be similar to those measured by the USGS in 1986, which is corroborated by the general agreement between 1986 sample results and BVWSD-reported 2008 TDS concentrations contours (**Water Figure 10**). In 2002, HydroFocus re-sampled shallow groundwater wells located north of BVWSD and in the area between Firebaugh and Kettleman City. The wells were originally sampled in 1984 (Deverel1984), and comparisons between results confirmed that groundwater quality changes were insignificant even though the two sampling events were separated by more than 20 years (HydroFocus2006).

The TDS concentrations in groundwater beneath the Buttonwillow Service Area vary with depth. For example, URS (2010a and 2010b) analyzed water samples and conducted down-hole specific conductance logging in seven wells. They concluded from the well water sample results that groundwater beneath the proposed well field is relatively higher in TDS concentrations and dominated by sodium and chloride ions, whereas samples from wells located further east are dominated by calcium and sulfate ions. Down-hole specific conductance logging suggested vertical stratification of groundwater salinity at some locations, and high salinity water in discrete zones.

When an aquifer is pumped by partially penetrating wells, upward movement of deeper groundwater to the well screens can occur (herein referred to as “up-coning”). In the San Joaquin Valley, saline (brackish) groundwater of sodium chloride water type reportedly underlies the base of the pumped groundwater zone (Page1973). **Water Figure 14** conceptually illustrates up-coning of brackish groundwater to variable depth pumping wells; the timing and quantity of up-coning groundwater is determined by the spatial distribution of active wells, their depths, the magnitude and timing of pumping, and the actual TDS concentration contrasts in groundwater with depth.

Beneath the Buttonwillow Service Area, Page (1973) mapped the depths to brackish groundwater (defined as groundwater having dissolved solids concentrations greater than about 2,000 mg/L) as generally ranging from less than 500 feet in the north to more than 700 feet in the south (**Water Figure 12**). These depths correspond to the bottom third of model layer 2 and upper 200 feet of model layer 3. Hence, simulated up-coning from model layer 3 can contribute to or replace the volume of extracted groundwater originating as inflow from below the well screens. The applicant and staff-modified models simulated proportional contributions of inflow from beneath the well screens that range from 58- to 63-percent of the extracted volume of groundwater, respectively (the volume of inflow from beneath the well screens divided by the annual pumping rate as reported in **Water Figure 15**). In additional model tests completed by staff, simulated inflow from beneath the well ranged from 64-percent (**Water Figure 16**) to 15-percent (**Water Figure 17**).

During the 25-year simulation period, not all up-coning is extracted by the partially penetrating wells.[4] Rather, the up-coning groundwater that remains replaces the relatively shallower groundwater that was extracted by the wells; a portion of the water extracted from the zone influenced by the pumping well (the ZOI) is replaced by up-coning from beneath the well screens (simulated up-coning in the staff-modified model as reported in **Water Figure 15**).

The applicant model did not show any flow induced from beneath 600 feet depth (upward flow from layer 3), unlike each of staff's model runs (**Water Figure 15, 16, 17**). In staff's modified, reduced storativity, and high anisotropy model, water from model layer 3 (below 600 feet depth) moved upward into model layer 2 (between 300 and 600 feet below land surface). The simulated annual flux rates, in AF/y year, are 2,101; 5,666; and 5,454; respectively. Each of these scenarios could represent an additional salt load to the aquifer system that is induced by project pumping but not accounted for in the applicant's model. Assuming the minimum salinity of the up-coning water is 2,000 mg/L, as much as 15,400 tons of salt could be induced to flow upwards from greater depths of the aquifer. Staff acknowledges that if the up-coning water is equal in quality to the water being pumped, there may be no net degradation. However, if the source of degraded water is beneath the "fresh" water at a depth between 500 and 700 feet, pumping which results in up-coning may be more likely to degrade the local aquifer than to improve it. The applicant's mis-application of "recharge" to their groundwater model likely resulted in a low estimate (zero) estimate of up-coning water. This potential source of salt was not analyzed by the applicant, but should be considered prior to concluding a benefit to water quality in the aquifer.

The concentrations of total dissolved solids are reportedly greater west of the well field. The quality of the water extracted by the well field is therefore determined by the spatial distribution of groundwater-flow paths and associated volumetric fluxes into the wells, which delineate the shape and extent of the ZOI. Staff did not calculate the net salt loading created under each of the different pumping/model scenario's, but notes that any quantification of the project's benefit to salt loads in the aquifer would require budgeting of water sources from the west and all other sources affected by the well field pumping. As staff has pointed out there is limited data to show what the source of salts is in the proposed pumping area. This salt loading may also contribute to a shift from calcium-sulfate to sodium-chloride dominated water, and an increase in TDS concentrations within the ZOI. This change in water quality could result in significant impacts to other reasonable beneficial uses.

[4] Staff utilized the post-processor MODPATH (Pollock1994) to delineate the pumping ZOI for the proposed well field, and the post-processor ZONEBUDGET (Harbaugh1990) to extract the simulated average annual volumetric water fluxes (volumetric water budget).

After 25-years of pumping, the applicant's model results indicate groundwater beneath about 1,400 acres will be extracted by the proposed well field. Most of this water (58-percent) comes from beneath the 300 feet deep well screens, and lesser volumes are contributed by horizontal inflow (34-percent), direct recharge (7-percent) and storage (1-percent). The proposed extraction wells remove substantially more horizontal inflow originating east of the well field (22-percent) relative to the assumed low quality water that originates west of the well field (12-percent).

The staff-modified model (no-flow boundary added and no recharge) simulates a slightly smaller pumping ZOI (1,300 acres). An even greater proportion of extracted groundwater (63-percent) is from beneath the well screens. The proportional contribution of horizontal inflow increases slightly to 36-percent (a net increase of 2-percent), and the remaining water extracted is removed from storage (1-percent); there is no recharge. Although the magnitude of inflow from the east decreases by about 20 AF/yr, its proportional contribution to the water extracted from the aquifer is the same (22-percent). Inflow from the west increases more than 120 AF/yr, and its proportional contribution to the pumpage increases from 12- to 14-percent.

Staff performed additional model testing which showed water quality extracted by the proposed well field is sensitive to assumed aquifer conditions. Utilizing the reported representative storativity (0.007) staff found the simulated pumping ZOI area has limited sensitivity to the change in storage coefficient because most of the groundwater extracted comes from beneath the well screens. The simulated pumping ZOI area mapped in **Water Figure 16** is 1,350 acres and only about 50 acres less than simulated by the applicant's model. The proportional contribution of water extracted from below the well screens increased slightly from 63- to 64-percent, and the relative contributions of horizontal flows originating east and west of the well field remained approximately the same.

Increasing the anisotropy substantially increased the pumping ZOI area from 1,350 acres to almost 3,100 acres (**Water Figure 17**). The proportional contribution of water extracted from below the well screens decreased dramatically from 58- to 15-percent, and the contribution from horizontal inflow increased from 34- to 85-percent; most of the horizontal inflow (53-percent) originates east of the well field and a lesser proportion (31-percent) originates west of the well field.

Estimated TDS Concentrations for Industrial Supply

Staff estimated the range in expected TDS concentrations in water produced by the proposed well field. Staff utilized well water sample results, reported TDS concentrations contours (1970-2007 composite contours and 2001 summer contours), and the 25-year pumping ZOI simulated by the applicant's model (URS2009). Staff utilized the ZOI from the applicant's model because there were negligible differences between the applicant and staff-modified models' ZOIs using a lower value for storativity (0.007). Furthermore, although the ZOI area for the staff-modified model increased following an increase in simulated anisotropy (**Water Figure 17**); it did not encroach into areas with additional sampling locations. The TDS concentration data and ZOI are mapped in **Water Figure 18**, and the estimated TDS concentrations based on several different approaches, are summarized below in **Water Table 6**.

Water Table 6
Estimated TDS Concentrations in Water Produced by the Proposed Well Field

ZOI sub-zone	Proportion of ZOI Area (percentage)	Well Field Concentration Estimates			
		1 (mg/L)	2 (mg/L)	3 (mg/L)	4 (mg/L)
A	16.8	1,930	780	2,000	3,000
B	16.5	1,930	399	2,000	3,000
C	18.8	1,930	2,400	2,500	3,000
D	16.2	1,930	2,900	3,000	3,000
E	13.9	1,930	2,030	3,000	3,000
F	17.8	1,930	1,160	2,500	3,000
Mixing Model Results		**1,930**	**1,606**	**2,484**	**3,000**

Approach 1: Representative ZOI quality based on median well water sample concentration.
Approach 2: Representative ZOI quality based on well water sample concentrations in six sub-zones.
Approach 3: Representative ZOI quality based on 1970-2007 composite TDS concentration contours and six sub-zones.
Approach 4. Representative ZOI quality based on summer 2001 TDS concentration contours and six sub-zones.

In the first approach, staff utilized the median observed TDS concentrations from one shallow well sample (1,930 mg/L), three deep well samples (399 to 2,900 mg/L), and one sample from a well of unknown depth (389 mg/L); all the sample locations are located within the simulated ZOI (**Water Figure 18**). The representative TDS concentration of groundwater extracted by the well field using the first approach (median concentration of the five samples) is 1,930 mg/L.

In the second approach, staff considered observed spatial variability in TDS concentrations and assigned a representative concentration to each ZOI sub-zone. The observed concentrations ranged from 389 to 2,900 mg/L (standard deviation of about 70-percent), and the contributing areas represented by the sub-zones range from 14- to 18-percent of the total ZOI area. The representative groundwater concentrations in sub-zones B, C, D and F were selected based on the water samples from wells located within the respective sub-zones (399, 2,400, 2,900, and 1,160 mg/L, respectively); the representative TDS concentration for groundwater in sub-zone F (1,160 mg/L) was estimated from the average of two samples located in the sub-zone (389 and 1,930 mg/L). No samples are located within sub-zones A and E. For sub-zone A, staff assumed a representative TDS concentration equal to the average of the representative concentrations in adjacent sub-zones B and F (780 mg/L). Similarly, the representative TDS concentration in sub-zone E is assumed equal to the average of the concentrations representing adjacent sub-zones D and F (2,030 mg/L).

Assuming the above TDS concentration estimates are representative for groundwater beneath the ZOI sub-zones, the expected composite TDS concentration in water produced by the well field was equal to the area-weighted average of each sub-zone concentration (almost 1,610 mg/L). If sample concentrations vary as much as 70-percent (the standard deviation of the sample results), the estimated TDS concentration in water produced by the well field ranged from 945 to 2,730 mg/L (calculations not shown in **Water Table 6**).

In the third approach, staff utilized TDS concentrations estimated from the composite 1970-2007 contours. The contours indicate a representative concentration of 2,000 mg/L beneath sub-zones A and B. The TDS concentration contours beneath sub-zones C and F range from 2,000 to 3,000 mg/L; hence, we assigned a representative TDS concentration of 2,500 mg/L to these two sub-zones. Sub-zones D and E are generally both located west of the 3,000 mg/L contour, and we assigned representative TDS concentrations beneath these two sub-zones equal to 3,000 mg/L. Assuming these TDS concentrations are representative for groundwater beneath the ZOI sub-zones extracted by the wells, the expected composite TDS concentration in water produced by the well field was equal to the area-weighted average of each sub-zone concentration (about 2,480 mg/L). After varying the contour concentrations by 50-percent of the contour intervals, the estimated TDS concentration in water produced by the well field ranged from 1,000 to 3,730 mg/L (calculations not shown in **Water Table 6**).

In the fourth approach, staff utilized summer 2001 contours which indicate TDS concentrations in groundwater beneath the well field are equal to 3,000 mg/L (**Water Figure 12**). Although observed TDS concentrations in samples from wells located west of the well field are spatially variable and less than 3,000 mg/L, we conservatively assumed TDS concentrations beneath the entire ZOI everywhere equal to 3,000 mg/L. The expected composite TDS concentration in water produced by the well field calculated by this fourth approach is equal to 3,000 mg/L. If the contour concentrations are varied by 50-percent of the contour interval, the estimated TDS concentration in water produced by the well field ranges from 2,500 to 3,500 mg/L (calculations not shown in **Water Table 5**).

Depending on the approach employed, the expected TDS concentrations in water produced by extraction wells operating in the proposed well field area could range from a minimum of about 945 mg/L to a maximum of 3,730 mg/L. This range in concentrations suggests the proposed groundwater supply is not sufficiently degraded such that it can’t be used for agricultural purposes and possibly as a drinking water supply.

Factors Affecting TDS Concentrations in Water from Proposed Well Field

Spatial variability in TDS concentrations in groundwater and the three-dimensional movement of groundwater to extraction wells contribute to uncertainty in the estimated water quality produced by the proposed well field. Observed well water concentrations are limited in number and represent variable sampling dates and well depths. Additionally, extraction wells can intercept groundwater moving both horizontally toward the proposed partially penetrating well screens and upward moving water originating from depths below the well screens.

There are only five samples from wells located within the simulated pumping ZOI, collected over a period of about 50 years (**Water Figure 18**). One of the samples is from a well of unknown depth (389 mg/L). The samples with the lowest TDS concentrations (389 and 399 mg/L) were collected in 1961; whereas the more recent samples collected in 2010 represent different locations and have substantially greater TDS concentrations.

At a workshop on February 20, 2013, staff discussed the results of the preliminary water supply analysis that raised questions about BVWSD's BGRP. At the workshop BVWSD indicated they had additional information that was not considered in staff's analysis. BVWSD requested that staff provide data requests indicating what data they would need to reevaluate the preliminary results and agree to maintain the confidentiality of information that may be submitted by BVWSD. Staff agreed but has not yet received responses to the data requests. Information provided by the district may improve staff's understanding of water quality in the district. Staff expects some new information to be incorporated in future iterations of this analysis, but will proceed with an independent analysis of impacts and alternatives if such information is not forthcoming.

Changes in Water Level and Storage

Many agricultural wells exist within the Buttonwillow Service Area, and a number of wells are monitored for water level and water quality data. Water level data for 64 wells obtained from California Department of Water Resources Water Data Library[5] were assembled and analyzed to identify trends and estimate average annual historical changes in groundwater storage.

In general, water levels were measured semiannually although most records were incomplete. For most years, the water levels were measured during the winter and fall, but in other years the data were collected in the spring and fall. Staff created a subset of 19 wells with at least 35 water level measurements each, spanning the period 1974-2001 (**Water Figure 19**). This subset includes the greatest number of wells with the longest period of over-lapping records and well locations that are spatially distributed across most of the Buttonwillow Service Area.

The Mann-Kendal test and Sen's slope estimator were calculated to determine significant water level trends. The data from most wells (14 of the 19 total wells) show a statistically significant upward trend at the 95 percent confidence level (**Water Table 7**). The significant upward trends range from 0.28 feet per year (ft/yr) to 1.27 ft/yr (average and median trend of 0.68 and 0.64 ft/yr, respectively).
Annual changes in groundwater storage (ΔS) were estimated using the calculated trends and the following equation:

$$\Delta S = A \cdot Sy \cdot \frac{\Delta H}{t}\text{; where,}$$

A is the area of the Buttonwillow Service Area (reported at about 45,000 acres);

Sy is the specific yield (assumed values ranging from 0.15 to 0.20); and,

$\frac{\Delta H}{t}$ is the calculated annual water level trend represented by the Sen's slope estimator (in ft/yr).

The average trend of 0.68 ft/yr indicates the annual increase in groundwater storage ranges from about 4,600 to 6,100 AF/yr (calculated using specific yield values ranging

[5] www.water.ca.gov/waterdatalibrary

from 0.15 to 0.20, respectively)[6]. The planned well field extraction rate (7,500 AF/yr) exceeds the average annual storage change during 1974 through 2001. Staff also reviewed aquifer testing results reported by URS to evaluate site specific conditions and found the data (2010a) indicate a geometric mean storativity of 0.007. Therefore, if this storativity value were representative for the area it would result in an even lower calculated 1974-2001 storage increase. These estimates suggest project pumping may have a larger impact to groundwater storage beneath the BVWSD than assumed by the applicant, and the proposed project pumping (7,500 AFY) likely exceeds the historical annual volume of water contributing to storage beneath the BVWSD. The consumption of stored groundwater will result in long-term water level declines beneath the BVWSD.

Water Table 7
Water Level Trends in Buttonwillow Service Area Wells

Map ID[a]	**Trend** (ft/yr)		
	alpha = 0.05		
	Years	Number of records	Observed
63	1974-2001	45	0.59
64	1974-2001	48	0.34
65	1974-2001	49	0.28
66	1974-2001	45	0.74
67	1974-2001	43	0.65
33	1974-2001	53	0.68
50	1974-2001	50	0.76
68	1974-2001	47	0.90
51	1974-2001	51	(0.44)
69	1974-2001	38	1.01
43	1974-2001	46	0.61
18	1974-2001	42	0.62
70	1974-2001	47	0.62
71	1974-2001	47	1.27
72	1974-2001	50	0.44
73	1974-2001	40	(0.16)
74	1974-2001	46	(0.01)
75	1974-2001	50	(0.01)
76	1974-2001	35	(0.49)
Average (significant trends)	---	---	0.68
Average (all trends)	---	---	0.56

a) Well locations and map ID numbers are shown in **Water Figure 7**.

The district's willingness to provide 7,500 AF/y may be unreasonable considering groundwater levels are declining in the Kern County subbasin. The KCWA budget for 1970 through 1998 indicates a negative change in storage of 325,000 AF/y. Over approximately the same time period, the storage change beneath the Buttonwillow Service Area (BSA) estimated from observed water level trends was positive and between 4,600 and 6,100 AF/y. Staff views this increase in storage as definite positive influence on basin storage during a period of significant and widespread storage decline in the Kern County subbasin. However if the proposed project pumping created a negative change in storage within the BSA, this would compound deficits in a basin that has experienced a perpetual decline in groundwater storage.

[6] 45,000 acres x 0.68 foot per year x 0.15 = 4,590 acre-feet per year;
45,000 acres x 0.68 foot per year x 0.20 = 6,120 acre-feet per year.

Project pumping and increased groundwater consumption could cause water level declines and reduce groundwater storage. Staff believes a consumptive use offset could be appropriate mitigation for this potential impact. Staff also believes a suite of possible methods could be implemented to offset project pumping such as developing alternative supplies or funding water conservation programs. The Kern County subbasin has a very high annual extraction rate and many groundwater users. The potential for achieving a water savings in this basin is therefore very good. Much of the basin's water use is non-uniformly metered and accounted for, further increasing the odds for funding a water savings program. These mitigation methods may include retirement of agricultural lands and irrigation efficiency improvement programs, such as micro-sprinkler or drip irrigation, drainage improvements, or tail water reuse. Utilizing other technologies such as dry cooling could also reduce water needed for industrial processes. Staff recommends adoption of Condition of Certification **WATER-3**, which requires the project owner to develop and implement a Water Supply Plan prior to project construction and provide water use offset within the Kern County subbasin that is equal to project pumping, thereby ensuring no new net increase in groundwater consumption. Staff will provide additional analysis concerning the various options for offsetting water use in the FSA/FEIS.

To ensure that the water use analyzed is consistent with that used by the proposed project, staff proposes Condition of Certification **WATER-4**. This condition would limit project pumping to an average of 7,500 acre-feet per year for project operations. Furthermore, this condition requires that water use is metered and reported consistent with these limitations. Staff also proposes Condition of Certification **WATER-5** to ensure that project wells are constructed to state standards.

Subsidence

Declining groundwater levels can cause dewatering and compaction of fine-grained sediment beds resulting in subsidence of the land surface. Hydrocompaction of moisture deficient deposits above the water table (shallow or near-surface subsidence), fluid withdrawal from oil and gas fields, and tectonic movement also contribute to land subsidence. In the San Joaquin Valley, aquifer-system compaction due to water-level decline and near-surface hydrocompaction are the primary causes of historical subsidence. Aquifer–system compaction could resume if groundwater consumption by the project caused water levels to decline below previous water-level lows.

The Buttonwillow Service Area is located adjacent to two major historic subsiding areas in the southern San Joaquin Valley; the Tulare-Wasco area to the northeast and Arvin-Maricopa area to the southeast. **Water Figure 20** shows lines of equal land subsidence mapped in these areas (Ireland&Others1984). They concluded that during the period 1926 to 1970, land surface declines in the Tulare-Wasco area ranged from a maximum of 12 feet near Pixley to a minimum of 2 feet near Wasco. In the Arvin-Maricopa area the land surface declines ranged from less than 1 foot to more than 9 feet. The primary cause of subsidence was declining groundwater levels in the confined zone due to the proliferation of wells and groundwater consumption for agricultural operations. In 1998, DWR concluded that about 1-foot of subsidence occurred since 1970 along a 29-mile reach of the California Aqueduct in an area west of Wasco and the Buttonwillow Service Area (Swanson1998).

Since 1994, the Department of Water Resources has operated an extensometer located about 17 miles southeast of the proposed well field. Details of extensometer construction were not available. **Water Figure 21** shows the measured aquifer compaction and expansion from 1994 to 2009. The water levels in the extensometer well and another nearby well (state well identification number of 29S24E11R001M) show declining groundwater levels since 2001. Groundwater levels reported for 2009 appear to be at their lowest since the start of the data record in 1983. We employed the Mann-Kendal test for trend and the Sen's slope estimator to determine the observed subsidence during this period was statistically significant and the downward trend at the 95% confidence level was 0.001 ft per year.

There is no historical evidence for subsidence in the Buttonwillow Service Area or immediate vicinity of the proposed well field. Statistical analyses of groundwater level data from wells located in the Buttonwillow Service Area indicate statistically significant upward water level trends since 1974 that range from 0.28 ft/yr to 1.27 ft/yr. These upward trends indicate groundwater storage increased on average during the 1974 through 2001 period (**Water Figure 19**). If these water level trends reverse, and water levels decline below historical lows, project groundwater use could contribute to an increased risk of land surface subsidence in the Buttonwillow Service Area. As discussed above in 'Changes in Water Level and Storage' the proposed use of 7,500 AF/y may have a larger impact to groundwater storage beneath the BVWSD than assumed by the applicant, and the proposed project pumping likely exceeds the current annual volume of water contributing to storage beneath the BVWSD. The consumption of stored groundwater will result in long-term water level declines beneath the BVWSD that could lead to subsidence. Staff is concerned that given the proximity to the California aqueduct and historic occurrence of subsidence during extensive groundwater use, there may be potential for significant impacts in the region from project pumping.

Given past and current groundwater pumping in the basin, subsidence could be occurring and project pumping could exacerbate subsidence rates and magnitude. It is unclear however, if subsidence is occurring on or near the proposed well field and whether any resources or structures could be affected by subsidence. Due to the uncertainty related to conditions at the project site, staff recommends that survey monuments be installed and monitoring stations established for assessment of long term changes that may occur as a result of subsidence due to groundwater pumping in the area. Staff also recommends the applicant be required to develop an action plan for mitigation of impacts based on analysis of monitoring station data. Staff recommends the project owner be required to implement Condition of Certification **WATER-6** to monitor and mitigate any potential impacts associated with ground subsidence due to project groundwater pumping. If intermediary measures in the adopted plan do not sufficiently address impacts resulting from subsidence, this condition would require the project to modify or cease pumping until the impacts can be addressed.

Construction and Drinking Water

The proposed project would be supplied with construction water and potable water during operations by either West Kern Water District (WKWD) or existing onsite wells. If delivered from WKWD, water would be delivered through a 1-mile pipeline that runs west to the project site. The onsite supply options would be to obtain supply water from one of the two alternative onsite wells, the Ackerman well or the Alternative B well. Maximum use from either supply would be up to 12 AF/y. A summary of average and maximum use rates for construction and potable water is summarized below in **Water Table 8**.

Water Table 8
Water Supply Quantities

	Supplier	Average Use (gpd)	Max Use (AF/y)	Maximum Use (gpd)
Construction Water	Onsite/WKWD	11,800	12	24,000
Potable Water (Operations)	WKWD	1,800	2	2,700

Source: AFC 2012, Table 5.14-8

Using the transmissivity (116,000 gal/day/foot) and storage coefficient (0.007) from the applicant's aquifer test (URS 2010j, Table 4), staff used the Theis equation to conservatively estimate impacts from pumping groundwater from construction. The average use rate during construction is expected to be 11,800 gpd. Over the construction period, pumping would result in less than a tenth of a foot of drawdown at a distance of 500 feet from the well. Based on this analysis staff concludes that the volume of water required for both construction and potable water would have no significant impact on local wells and aquifer storage.

Similar to the project's proposed use of groundwater within the BVWSD, use of groundwater from the WKWD would contribute to cumulative overdraft of the Kern County subbasin. The project's use of water for construction and domestic uses should be offset by the replacement of water in the basin. Staff proposes Condition of Certification **WATER-3** to mitigate for the proposed project's contribution to overdraft. Staff also proposes **WATER-4** which would limit construction water use to 12 AF/y.

CUMULATIVE IMPACT ANALYSIS

A project may result in a significant adverse cumulative impact where its effects are cumulatively considerable. "Cumulatively considerable" means that the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of reasonably foreseeable future projects (California Code of Regulations, Title 14, section 15130).

The HECA project would be located within the Kern County subbasin, which would be the groundwater unit across which a cumulative impact from the project should be analyzed. Due to the large extent of the Kern County subbasin it is difficult to assess the extent of foreseeable projects that could impact the groundwater balance. However, the available basin budget analyses reviewed by staff indicate that uses within the Kern County subbasin may already exceed supply. The project's potential incremental impact would be additive and cumulatively considerable. If the Kern County subbasin is in a state of overdraft, the proposed project's pumping would contribute to the water storage deficit. Though BVWSD's contribution to the Kern County subbasin is currently positive, the use of 7,500 AF/y of water by the project can potentially exacerbate overdraft conditions in the Kern County subbasin and create a significant adverse impact. Staff recommends adoption of Condition of Certification **WATER-3**, which requires the project owner to develop and implement a Water Supply Plan prior to project construction and provide water use offset within the Kern County subbasin that is equal to project pumping, thereby mitigating for any cumulative impact to the water balance of the Kern County subbasin.

WATER SUPPLY ALTERNATIVES

The AFC contained a number of water use alternatives, but failed to consider dry cooling. Dry cooling is worthy of consideration for at least the two following reasons:

- The proposed project could be the most water intensive power plant in California.
- The proposed project has the potential to create significant impacts to water resources.

The applicant states that dry cooling is infeasible in Data Response A203 by stating:

- Capital cost differential of approximately $20-30 million
- Reduced power output of between 20 to 40 megawatts
- Overall total cost impact of about $50 million

Staff has not yet been able validate or deny the applicant's statement about the infeasibility of the dry cooling alternative, but notes that the following factors do not appear to have been considered by the applicant:

- The energy required to move 7,500 acre-feet per year, 15 miles, and about 30 feet upgradient.
- The untreated water cost of $3,375,000 per year, or $84,375,000 over a 25-year period
- Cost of treating 7,500 acre-feet per year with zero liquid discharge (ZLD) technology.
- Disposal of ZLD solids that may be generated if untreated process water contains high concentrations of total dissolved solids.

As stated in previous sections of this analysis, the Kern County subbasin is in overdraft. The proposed pumping does not provide any obvious benefit to local landowners or their water supply. The quality of water produced by the proposed well field may not be sufficiently degraded to justify power plant use. As also stated in this analysis, in some cases the impact to water resources may be proportional to the volume pumped, and likewise, any decrease in water use could contribute to a lessening of the impact, proportional to the decrease. It is therefore reasonable to consider dry cooling to reduce the potential project's water consumption. Dry cooling has the potential to create the following benefits:

- Reduce project water demand to roughly 10-percent of the currently proposed amount, which could result in a cost savings of approximately $75,937,500 over a 25-year period.
- Energy savings over a 25-year period from reduced water transport.
- Significantly reduce the contribution to overdraft in the Kern County subbasin.
- Reduce project-induced drawdown in local water wells in an area that has been identified as an Environmental Justice population.
- Reduce potential for inducing lower quality water to the pumping field aquifer area.
- Reduce potential for impacts to the California Aqueduct from subsidence.

Given staff's current conclusions regarding impacts to basin overdraft and groundwater quality, and consistency with the water policy, staff believes dry cooling should seriously be considered as an alternative to the project's current water use proposal. Staff intends to provide a more detailed analysis of this alternative technology in the FSA/FEIS.

A number of alternative water supplies for the proposed HECA project are provided within Section 6.0 (Alternatives) of the AFC (2008), Revised AFC (2009), and Amended AFC (2012). Based upon the water supply alternatives identified above within the subsection entitled **ALTERNATIVES CONSIDERED WITHIN THE APPLICATION FOR CERTIFICATION**, the following alternatives have been eliminated from further consideration by the applicant, but not necessarily by staff:

- <u>Ocean Water Alternative</u>. The proposed HECA project site is approximately 75-miles from the Pacific Ocean. Although this supply is virtually limitless and desalination technology is successfully proven, the capital cost for transporting, treating, and disposing of this option is high, exceeding $500 million (HECA 2012e, Section 6.0, p. 6-24). Upon review, staff has determined that constructing a pipeline this distance would result in increased environmental impacts compared to those of the proposed HECA project. Additionally, Energy Commission and other state agency directives are eliminating use of ocean water for power plant cooling. Based upon these factors, an ocean water supply alternative is considered infeasible and is, therefore, eliminated from further consideration.
- <u>Ocean Discharge Alternative</u>. Identical to that discussed above for an ocean water supply alternative, staff has determined that constructing a pipeline this distance would result in increased environmental impacts compared to those of the proposed HECA project. While it is assumed this alternative would capture water prior to being discharged to the ocean, it would result in a decrease to ocean water inflow and be inconsistent with overall Energy Commission and other State agency directives toward eliminating use of ocean water for power plant cooling. Based upon these factors, an ocean discharge alternative is considered infeasible and is, therefore, eliminated from further consideration.
- <u>Brackish Water - Industrial Wastewater</u>**.** The project applicant has indicated that producers of industrial wastewater are willing to provide this water to the proposed HECA project (HECA 2012e, Section 6.0, p. 6-25). However, they are reluctant to guarantee specific quantities of future water supply (HECA 2012e, Section 6.0, p. 6-

25). Additionally, the proposed HECA project applicant estimated the capital cost to construct a water plant to process this raw water supply could be $200 million and could result in a nearly 15 MW additional parasitic load over use of brackish groundwater (HECA 2012e, Section 6.0, p. 6-25). The proposed HECA project applicant has indicated that these capital and operating costs are substantial and deem this alternative infeasible.

The thermal treatment technology would produce a concentrated brine waste stream (HECA 2012e, Section 6.0, p. 6-25). Based upon water quality data already obtained, it is possible that this reject stream will have constituents at sufficient levels to trigger classification of the brine waste stream as hazardous waste (HECA 2012e, Section 6.0, p. 6-25). This waste generation could conflict with the intent of the proposed HECA project design to minimize the production of hazardous waste to the extent feasible (HECA 2012e, Section 6.0, p. 6-25).

In summary, the applicant has indicated that although oilfield-produced water appears to be technologically possible as a water supply to the proposed HECA project, it is not the preferred option, due to availability, environmental, waste disposal, and cost considerations (HECA 2012e, Section 6.0, p. 6-25).

Staff's independent review of this alternative has likewise determined that this alternative is technologically feasible. Appendix A of the AFC states, "Total dissolved solids concentrations can be as high as 5,000 parts per million (ppm)." Water of this quality would likely comply with the Energy Commission's Water Policy. This option would also be less energy intensive for water transport to the site. The HECA site is down gradient and approximately 3 miles from the Elk Hills oil field, whereas the site is uphill and 15 miles from the proposed well fields. The difference in cost of getting water to the site between the two options may be substantial.

Even though 7,500 acre-feet per year may not be available from the oil field, some lesser amount may be feasible. Staff is still seeking information about the amounts of water available from local oil fields. In addition it is not clear to staff whether a significant volume of hazardous waste would be generated. The brine can often be managed such that the concentrations are kept below the threshold values. Further analysis may show that given disposal options currently available it may be a viable alternative.

- <u>Brackish Water – Semitropic Water District</u>. The project applicant has indicated that Semitropic Water District was unable to verify the water supply quantity and composition and, therefore, unable to provide a firm water supply commitment for the proposed HECA project (HECA 2012e, Section 6.0, p. 6-24). Staff independent review of this alternative has not been able to validate the applicant's statements in the AFC. At this time, staff cannot eliminate this alternative.
- <u>Inland Wastewater – Municipal Effluent Alternative</u>. Currently, the city of Bakersfield is selling its treated effluent to local farmers for irrigation purposes. They do not have excess capacity outside of existing contracts, which could supply the proposed HECA project with its total water needs (HECA 2012e, Section 6.0, p. 6-27). This provider does have some excess production (approximately 1 million gallons per day), which is expected to increase prior to proposed HECA project start-up. This growth rate is estimated at approximately 0.25 million gallons per day (mgd) per year, resulting in another 1 mgd available by 2014.

This amount is insufficient to supply all of the HECA project needs (6.624 mgd), and would have to be augmented by an additional water supply (HECA 2012e, Section 6.0, p. 6-27). Based upon staff's preliminary review of this factor, a Municipal Wastewater Effluent Alternative option is considered infeasible to meet all of the proposed project needs, but cannot be eliminated because this source could supply a substantial portion of the needs. Staff experience also suggests the contracts with farmers may not be firm and a recycled water provider will often prefer contracting with an industrial facility that will use the supply on a consistent and reliable basis. If the proposed project were to use some proportion from this source, the level of potential impacts to water resources from the proposed project could be reduced. This is particularly true, when compared to the current use of the supply for agriculture which has a high return flow, because it is possible there is increased salt load to the aquifer where the water is applied. Such potential salt loading would not be consistent with current state policy. Consumptive use at a power plant would generally be a preferred alternative. Furthermore, this option for the water source would likely comply with the Energy Commission's water policy and state policy that encourages the use of reclaimed water for power plant cooling.

- Inland Wastewater – Agricultural Wastewater Alternative. Agricultural wastewater (i.e., tile drainage) is excess water from irrigation practices. This wastewater is not available in sufficient quantities in the vicinity of the proposed HECA project site, nor is it sufficiently reliable for use at the proposed HECA project due to water quality variability (HECA 2012e, Section 6.0, p. 6-27).

  Based upon staff independent review of this alternative, an agricultural wastewater supply alternative option is considered potentially feasible and cannot be eliminated from further consideration. The amount available from the Buena Vista Water Storage District's Target Area A is 4,500 acre-feet per year, which is insufficient to supply all of the HECA project needs (6.624 mgd), but could be augmented by an additional water supply (HECA 2012e, Section 6.0, p. 6-27). This volume may also be sufficient to meet the needs for the alternative where there is no fertilizer facility included. If the proposed project were to use some proportion from this source, the level of potential impacts to water resources from the proposed project could be reduced. Furthermore, this option for the water source would likely comply with the Energy Commission's water policy and state policy that encourage the use of reclaimed water for power plant cooling.

- Other Inland Waters – State Water Project Alternative. Water supply from the State Water Project was evaluated in comparison to the proposed HECA project brackish groundwater supplier (BVWSD). The aqueduct located directly south of the proposed HECA site delivers State Water Project water. However, the proposed HECA project would not receive an allocation for the use of freshwater from the State Water Project (HECA 2012e, Section 6.0, p. 6-27).

  The use of fresh water for power plant cooling is discouraged through state guidance and policy. This factor, when considered with the fact that no specific allocation is identified, makes the State Water Project water supply alternative infeasible. This alternative is therefore eliminated from further consideration.

- Other Inland Waters – Fresh Groundwater Alternative. Water supply from inland groundwater was evaluated in comparison to the proposed HECA project brackish groundwater supplier (BVWSD). Given the availability of other viable sources of water, use of this freshwater supply would be inconsistent with the California Water Policy (HECA 2012e, Section 6.0, p. 6-27).

The use of fresh water for power plant cooling is discouraged through state guidance and policy. This factor, when considered with the fact that no specific allocation is identified, makes the fresh groundwater alternative water supply infeasible. This alternative is therefore eliminated from further consideration.

- Other Inland Waters – Municipal Water Supply Alternative. Water supply from inland municipal water suppliers was evaluated in comparison to the proposed HECA project brackish groundwater supplier (BVWSD). Given the availability of other viable sources of water, use of this water supply would be inconsistent with the California Water Policy (HECA 2012e, Section 6.0, p. 6-28).

  The use of fresh water for power plant cooling is discouraged through state guidance and policy. This factor, when considered with the fact that no specific allocation is identified, makes the State Water Project water supply alternative infeasible. This alternative is therefore eliminated from further consideration.

COMPLIANCE WITH LORS

WATER USE LORS AND STATE POLICY AND GUIDANCE

The Energy Commission has at least four sources for statements of policy relating to water use in California applicable to power plants. They are the California Constitution, the Warren-Alquist Act, the Commission's restatement of the state's water policy in the 2003 Integrated Energy Policy Report ("IEPR"), and the State Water Resources Control Board ("SWRCB" or "Board") resolutions (in particular Resolutions 75-58 and 88-63).

California Constitution

Article X, section 2 prohibits the waste or unreasonable use, including unreasonable method of use, of water, and it requires all water users to conserve and reuse available water supplies to the maximum extent possible (Cal. Const., art. X, § 2). Groundwater is subject to reasonable use (*Katz v. Walkinshaw* (1903) 141 Cal. 116).

Warren-Alquist Act

Section 25008 of the Energy Commission's enabling statutes echoes the Constitutional concern, by promoting "all feasible means" of water conservation and "all feasible uses" of alternative water supply sources (Pub. Resources Code § 25008).

Integrated Energy Policy Report

In the 2003 Integrated Energy Policy Report (IEPR or Report), the Energy Commission reiterated certain principles from SWRCB's Resolution 75-58, discussed below, and clarified how they would be used to discourage use of fresh water for cooling power plants under the Commission's jurisdiction. The report states that the Commission will approve the use of fresh water for cooling purposes only where alternative water supply sources or alternative cooling technologies are shown to be ''environmentally undesirable" or "economically unsound" (IEPR (2003), p. 41). In the report, the

Commission interpreted "environmentally undesirable" as equivalent to a "significant adverse environmental impact" under CEQA, and "economically unsound" as meaning "economically or otherwise infeasible," also under CEQA (IEPR, p. 41). CEQA and the Commission's siting regulations define feasible as "capable of being accomplished in a successful manner within a reasonable amount of time," taking into account economic and other factors (Cal. Code Regs., tit. 14, § 15364; tit. 20, § 1702, subd. (f)). At the time of publication in 2003, dry cooling was already feasible for three projects—two in operation and one just permitted (IEPR, p. 39).

The report also notes California's exploding population, estimated to reach more than 47 million by 2020, a population that will continue to use "increasing quantities of fresh water at rates that cannot be sustained" (IEPR, p. 39).

State Water Resources Control Board Resolutions

The SWRCB not only considers quantity of water in its resolutions, but also the quality of water. In 1975, the Board adopted the *Water Quality Control Policy on the Use and Disposal of Inland Waters Used for Power Plant Cooling* (Resolution 75-58). In it, the Board encourages the use of wastewater for power plant cooling. It also determined that water with a TDS concentration of 1,000 mg/L or less should be considered fresh water (Resolution 75-58). One express purpose of that resolution was to "keep the consumptive use of fresh water for power plant cooling to that *minimally essential*" for the welfare of the state (*Ibid*; emphasis added).

In 1988, the Board determined that water with TDS concentrations of 3,000 mg/L or less should be protected for, and considered as, potential supplies for municipal or domestic use unless otherwise designated by one of the Regional Water Quality Control Boards (Resolution 88-63).

NOTEWORTHY PUBLIC BENEFITS

Staff has not identified any noteworthy public benefits of the proposed project that are associated with water resources.

DOE'S FINDINGS REGARDING DIRECT AND INDIRECT IMPACTS OF THE NO-ACTION ALTERNATIVE

Under the No-Action Alternative, DOE would not provide financial assistance to the applicant for the HECA project. The applicant could still elect to construct and operate its project in the absence of financial assistance from DOE, but DOE believes this is unlikely. For the purposes of analysis in the PSA/DEIS, DOE assumes the project would not be constructed under the No-Action Alternative. Accordingly, the No-Action Alternative would have no impacts associated with this resource area.

Water Table 9
Response to Agency and Public Comments

Cmnt	From	Date	COMMENT TOPIC	RESPONSE
1			**Government Agencies**	
1.1	**EPA Region IX**	**July 26, 2012**	The DEIS should identify the potential effects on other water users and natural resources in the project's area of influence from project water use.	This analysis provides a description of the potential effects on other water users and natural resources in the project area.
1.2	**Kern County**	**March 6, 2013**	Therefore, the PCDD requests that the CEC's CEQA document include information on the following: (a) Will the brackish water source be available for the life of the project? Please include substantial data to support conclusions; (b) What is the alternative water source if the BWVSD supply becomes unavailable? Section 6.7 of the application lists several alternatives; including municipal effluent, State Water Project and fresh groundwater supplies; however, Staff notes that none of these listed alternatives are feasible because the site is not near a municipal effluent supplier, State Water Project waters have not been allocated, and state law does not allow power plants to use fresh groundwater sources; (c) Could the proposed brackish water be used for agricultural irrigation purposes?	(a) This analysis describes the availability of water, however staff did not find that waters of different quality were more plentiful or scarce in supply. See the "Groundwater Quality Impacts" section of this analysis for analysis of water quality impacts and policy on water use, respectively. (b) The applicant has not identified a back-up supply. Staff analysis indicates the proposed supply may not be suitable for the intended use based on state water policy. Staff currently believes more data and analysis is needed to evaluate the primary supply and determine whether other alternative supplies may be more appropriate prior to identifying a back-up supply. (c) The results of this analysis suggest that water produced for this project may be acceptable for agricultural irrigation. Other public comments suggest the same. See the "Groundwater Quality Impacts" section for further analysis.
	Shafter-Wasco Irrigation District	**March 14, 2013**	I understand that there is a significant demand, in the order of 7,000 acre-feet per year, of water supply to operate the proposed Hydrogen Energy California (HECA) project near	The applicant has not proposed to replace water in the basin to offset their use. See "Changes in Water Level and Storage" section of the analysis above and Condition of Certification WATER-3 for proposed

Cmnt 1	From	Date	COMMENT TOPIC Government Agencies	RESPONSE
			Buttonwillow. The district is requesting information on the source of this water and how the water supply in our basin is being impacted. If removed from the basin what are the plans to replace this water?	mitigation of potential overdraft impacts.
2.1	**AIR Data Request s**	**March 23, 2012**	7. AIR notes that the plan is to continue the proposal to use a brackish water supply for process water needs. What is HECA's definition of brackish water in mg/L of dissolved salts. What is the level of salts in the proposed brackish water? Is there a guarantee that water below a certain level of salts will not be used by HECA for process water?	Please see the "Groundwater Quality Impacts" section for further analysis.
2.2	**Kern County Farm Bureau**	**July 12, 2012**	I am here to advise you of our initial concerns on the impacts the proposed hydrogen energy project would have on agriculture and those who live on and work the land in the Buttonwillow community. Specifically; "Disruption to local water delivery infrastructure,"	Staff analyzed well interference that could be caused by project pumping and identified mitigation for any potential impacts in Condition of Certification WATER-1 and -2.
2.3	**Chris Romanin i**	**July 12, 2012**	What if the unforeseen happens…. a problem with their pipes, an earthquake, an accident, or an unknown that has not been regulated yet, or something else. Our ground water will be contaminated. Contaminated water is impossible to correct.	Staff would require that all hazardous material/ contaminants are handled appropriately according to the law. Please see the **Hazardous Materials** and **Waste Management** sections for details about material handling and containment requirements.
3.1	**Marjorie Bell**	**July 26, 2012**	In addition, the HECA plant will use "brackish" water (huge quantities of it) as a coolant on the theory that there are huge quantities to be had in this valley. As one farmer said at the hearing, slightly brackish water can be used on certain crops,	Staff acknowledges that the water proposed for use may be acceptable irrigation water for some farmers in the district. Staff provides some discussion in this analysis that explains these uses. Others have also questioned the available volume of "brackish" water available for

Cmnt 1	From	Date	COMMENT TOPIC **Government Agencies**	RESPONSE
			especially when mixed with fresh water. This isn't necessarily waste water we are talking about. It is water already being used successfully for crops. And what will happen when the brackish water is gone? The plant will then begin to use fresh water, which is currently in diminished supply because of a drought that may well continue into the next century.	project use. The staff analysis shows that water of different qualities could be blended by the proposed wells to produce the water supply. The degree of blending that would occur is difficult to quantify. The applicant also has yet to identify the source of the lower quality waters in the district and it is therefore difficult to evaluate the quantity that may be available.
3.2	**Kendell Heck**	**July 27, 2012**	I live right down the road from HECA. I'm afraid for my air, water, traffic, and those tall smoke stacks are terrible.	Please see the above analysis of potential impacts to water resources. Staff is awaiting additional data to complete analysis for potential impacts of the proposed water supply. Where appropriate staff has identified mitigation measures to ensure there would be no impacts to other water users in the basin. Please continue to provide comments that articulate your concerns.
3.3	**Richard and Jan Wolfe**	**July 30, 2012**	We also have drilled our own water well. The new plant will also be pulling from the same water table. If this causes the water table to lower too much, we may have to re-drill our water well deeper. Who's gonna pay for that? We sure can't afford it!	The project owner would be required to mitigate for an impact like this through a payment to the well owner. Condition of Certification WATER-1 would require the applicant to reimburse local well owners for this impact.
3.4	**Cindy Stiles**	**August 3, 2012**	I believe the promise of jobs for our county has blinded the local officials to the negative impact this factory will have: more-brackish ground water to irrigate our crops (this will negatively impact crop yield);	Staff is examining these issues closely. Please review sections of the Preliminary Staff Assessment that address your concerns.

Cmnt 1	From	Date	COMMENT TOPIC Government Agencies	RESPONSE
3.5	**Debbie Shepher d**	**August 3, 2012**	Water: Define brackish water and is it going to be long term? What impact is this going to have on the water table? Who or what is going to control how much water the plant uses?	The term brackish has different definitions depending on who defines it. Staff described some of the uses for water of different quality in this analysis. Generally staff believe brackish should be used to define water with limited beneficial uses due to a high salt concentration. Staff analyzed and described the potential water level lowering that could result from this project in this analysis. The amount of water that would be used by the project would be regulated through Condition of Certification WATER-4.
3.6	**Trudy Douglas**	**Septemb er 21, 2012**	The HECA coal powered chemical factory will put 520 tons of pollution and particulates into the air a year and use 6.6 million gallons of water a day. These are issues that we must examine closely but, the CEC seems not to be interested in helping us to do so.	Staff is examining these issues closely. Please review sections of the Preliminary Staff Assessment that address your concerns.

STAFF CONCLUSIONS

Staff evaluated the reasonableness of water use using multiple sources of guidance. Ultimately, staff attempts to uphold Article X, Section II of the California Constitution which states that water shall not be wasted. In the context of power plant water use, this equates to the “least of the worst,” which means a project should demonstrate that it uses the least amount of the poorest quality water available.

The project proposes to use up to 7,500 AF/y, which is significantly more water per megawatt than other recently licensed projects. Staff understands that approximately 30 percent of the proposed water use would go to the gasification process, but even then the projected water use required produce up to 300 MW net is inordinately high.

Presumably at the time of the original AFC (July, 2008), the applicant also considered the pumping in the context of SWRCB Resolution 75-58 which states that water with TDS above 1,000 mg/L might be a preferential source for power plant cooling. Furthermore, staff does not agree that the proposed pumping would constitute reclamation. Water below 2,000 mg/L TDS would certainly not qualify as significantly degraded (**Water Table 5)**, based on data that indicates this water is not only suitable for agriculture, but widely used in the region for this purpose. Water between 2,000 and 3,000 mg/L TDS could generally be considered degraded in terms of agriculture supply, which is the region's primary use, but would still be a source worthy of protection for potential domestic supply (SWRCB, Resolution 88-63).

Recent studies and intervenors that farm in the area point out that the water supply is still beneficial for irrigation of crops grown in the district and should be protected for those purposes. A source worthy of protection, is at the very least, not degraded enough to justify reclamation but still subject to reasonable use. The applicant's belief that the project could reclaim portions of the BVWSD may be true, but staff would not label pumping as a reclamation activity when there may be other reasonable beneficial uses of a supply with TDS concentration of 2,000 to 3,000 mg/L. Staff can only support the use of groundwater greater than 3,000 mg/L for cooling, given the high volume required for this project and the need to be consistent with using "the least of the worst". Staff's estimate that the project's water use would likely range from a minimum of about 945 mg/L to a maximum of 3,730 mg/L in TDS concentrations using the limited groundwater quality data available suggests it is likely the proposed pumping would not produce a sufficiently degraded supply.

As stated in this analysis, the district's willingness to provide 7,500 AF/y to the project may be unreasonable considering that the Kern County subbasin is in overdraft and considering that the district average water level increase is not as high as 7,500 AF/y. The KCWA budget for 1970 through 1998 indicates a negative change in storage of 325,000 AF/y. This indicates that the Kern County subbasin was in overdraft during that period and is likely still in overdraft. Over approximately the same time period, the storage change beneath the Buttonwillow Service Area (BSA) estimated from observed water level trends was positive and between 4,600 and 6,100 AF/y. Staff views this increase in storage as a positive influence on basin storage during a period of significant and widespread storage decline in the Kern County subbasin. However if the proposed project pumping created a negative change in storage within the BSA, this would compound deficits in a basin that appears to be in overdraft.

The proposed use would appear more reasonable if it were able to achieve multiple benefits. For instance, if the project was supplied with water from a remediation project the use of water within the Kern County subbasin would be more reasonable. The current location would supply a large volume of groundwater of an unsure quality, TDS concentrations between 1,000 mg/L and 4,000 mg/L. Assuming the worst case scenario, where the supply is closer to 1,000 mg/L, the project may have no quantifiable benefit other than providing an industrial water supply. However if the project were to pump shallow groundwater from the northern Buttonwillow Service Area, which is a known regional issue, it is much more likely that the project could at least lower the shallow groundwater table beneath the root zone and perhaps also remove water with no other beneficial uses. BVWSD's FEIR states that the district is interested in pumping water from their Target Area A, which has a shallow groundwater problem and is available in sufficient quantity to supply a significant portion of the project needs.

STAFF'S PROPOSED AREAS OF FURTHER REVIEW

Staff believes that other well configurations or locations could more effectively capture poor quality water or water with no other beneficial uses. If the project's pumping were able to better induce horizontal flow, particularly flow from the east, it is more likely that pumping could remove brackish water from the local aquifer. Staff believes this effect could be accomplished by a couple of distinct changes in the pumping strategy.

- As described in this analysis and in the BVWSD FEIR, the northern portion of the district appears to contain low quality water at shallower depths. This water is detrimental to agriculture and should be removed from the crop root zone. In their FEIR, BVWSD identifies the intent to develop brackish groundwater remediation in the northern BSA and produce up to 4,500 AF/y, in addition to the supply allocated for HECA. Staff believes this opportunity provides a much greater potential for meeting the proposed objectives of remediation and power plant cooling supply. Supply wells located in BVWSD's northern BSA are more likely to remediate agricultural lands and produce a consistent poor quality supply.
- The applicant has not sufficiently evaluated alternative water sources that may better satisfy water policy concerns. The Revised Application for Certification contains a brief description of the alternative water supplies considered for the project. The description of the alternative, agricultural wastewater, is very brief and general. BVWSD's Water Balance (FIER, 2009) indicates that surface outflow from the agriculture-dominated district may be significant. Staff is also aware that BVWSD is exploring methods for treatment and options for reuse of agricultural drainage, see "Low-pressure RO membrane desalination of agricultural drainage water," published in Desalination in 2003. Staff also notes approximately 12,000 to 15,000 acres of the Buttonwillow Service Area located north of the proposed well field is affected by a shallow water table. Use of this alternative water supply by HECA could provide dual benefits of root zone salt balance and improved soil aeration in the affected area.
- Staff is interested in learning more about the proposed well field and potential water quality that may be produced from it. Additional wells may provide useful information about how water quality varies with depth at the proposed well field site and also may help provide clarity in future discussions on water policy and potential impacts.
- Water alternatives dismissed by the applicant such as municipal wastewater from Bakersfield, oil field wastewater, or BVWSD Target Area A water, were eliminated because they can't supply the proposed project's entire water supply. However it is unreasonable to dismiss all of these options when any one of them could provide up to 50 percent of the project's water needs.

- The applicant has also neglected to adequately consider a dry-cooled project alternative. As stated in this analysis, in some cases the impact to water resources may be proportional to the volume pumped, and likewise, any decrease in water use could contribute to a lessening of the impact, proportional to the decrease. It is reasonable to consider dry cooling to reduce the potential project's water consumption. Dry cooling has the potential to: a) reduce project water demand to roughly 17-percent of the currently proposed amount, and thereby b) reduce untreated water costs by approximately $70,000,000 over a 25-year period.

ENVIRONMENTAL ANALYSIS OF CO_2 INJECTION

This section of the PSA/DEIS analyzes potential impacts to water resources from the construction and operation of the Occidental of Elk Hills, Inc. (OEHI) CO_2 Enhanced Oil Recovery component(OEHI). Where the potential of a significant impact is identified, staff proposes mitigation to reduce the significance of the impact and, as appropriate, recommended conditions of certification.

PROPOSED PROJECT DESCRIPTION

Occidental of Elk Hills, Inc. (OEHI) is proposing to extend the life of the Enhanced Oil Recovery (EOR) operations at their Elk Hills, California site by utilizing carbon dioxide (CO_2) to facilitate oil production from its Elk Hills Unit operations. The OEHI component would require carbon dioxide produced by the proposed Hydrogen Energy California (HECA) project. The HECA project would be located approximately three miles north of the Elk Hills Unit and will generate CO_2 from an Integrated Gasification Combined Cycle (IGCC) power plant. HECA would utilize technology capable of capturing over 90 percent of the CO_2 produced during facility operations. This 2.6 million tons per year of CO_2 would be compressed and delivered via a new 12-inch diameter pipeline to OEHI's EOR processing facility. Approximately 0.4 million tons per year would not be sequestered but used in fertilizer production.

The source of non-potable water for the proposed project is the Tulare aquifer. The project site is located within the Kern County subbasin of the San Joaquin Valley groundwater basin. The depth to groundwater ranges from 380 feet to as much as 780 feet below the surface. The groundwater has both artificial and natural sources. The artificial sources are from injection of produced water. The natural source of groundwater recharge is likely from the Temblor Range to the west. The Tulare aquifer is an exempt aquifer within the Elk Hills and currently accepts produced water from oil production activities at the Elk Hills oil field. The groundwater in the Tulare aquifer is highly mineralized and generally poor quality. Total dissolved solids concentrations can be as high as 5,000 parts per million (ppm) (AFC, 2012).

Project Water Supply

The project proposes the use of five existing make-up water wells with the permitted capacity of producing 50,000 barrels of water per day each. OEHI anticipates that approximately 10,000 barrels of water for each well per day will be produced to support the project. There are no other pre-existing wells located nearby that could be affected by OEHI's proposed use of the five groundwater production wells such that production rates of other wells would drop to a level that would not support existing land uses or planned uses for which permits have been granted. The OEHI component would therefore not substantially deplete groundwater supplies or interfere substantially with groundwater recharge such that there would be a net deficit in aquifer volume or a lowering of the local groundwater table level that would have the potential to adversely affect other existing or planned uses of the Tulare Aquifer. This is a less than significant impact.

No local well owners are known to rely on the aquifer in this area for a domestic or agricultural supply. No well owners would therefore be impacted by water level lowering as a result of the proposed project pumping. Impacts resulting from the project's water use would be less than significant. Staff does not propose any mitigation for the project's water use. OEHI's water use would not result in any potential impacts due to subsidence.

Staff reviewed the EOR component of this project for its potential impact to underground sources of drinking water (USDW). Geologic sequestration of CO_2 through well injection meets the definition of "underground injection" in section 1421(d)(1) of the Safe Drinking Water Act (SDWA). The EPA has authority for underground injection under the SDWA Underground Injection Control (UIC) program. In California, the EPA granted primacy to DOGGR to regulate Class II injection wells which includes wells used for enhanced oil recovery but not carbon capture and sequestration. Also pertinent to sequestration is Public Resources Code, Section 3106, which requires DOGGR to supervise the drilling, operation, maintenance, and abandonment of all wells drilled in California for the purpose of injecting fluids for stimulating oil or gas recovery. To meet the requirements of the SDWA, OEHI is obtaining a UIC permit through DOGGR to protect underground sources of drinking water from potential impacts related to the enhanced oil recovery injection operations. For more information on the proposed injection wells, please see the **Carbon Sequestration and Greenhouse Gas Emissions** section of this PSA/DEIS. Potential impacts related to subsidence from this project component are also discussed in this section.

PROPOSED CONDITIONS OF CERTIFICATION

Staff has provided preliminary conditions of certification that could be used to mitigate potential impacts from basin overdraft, well interference, and subsidence. However, these conditions are only applicable if it can be shown through further analysis that potential groundwater quality impacts identified herein are not a concern. In addition, given staff's current conclusions, a more rigorous analysis of alternatives must be conducted to show there is no other economically feasible and environmentally desirable water supply available. Staff is currently researching water supply alternatives and expects to release its conclusions and recommendations in the Final Staff Assessment.

WATER LEVEL MONITORING FOR IMPACTS TO NEIGHBORING WELLS

WATER –1: The project owner shall submit a Groundwater Level Monitoring, Mitigation, and Reporting Plan to the CPM for review and approval in advance of construction activities and prior to the operation of onsite groundwater supply wells. The Groundwater Level Monitoring, Mitigation, and Reporting Plan shall provide detailed methodology for monitoring background and site and off-site groundwater levels. The monitoring period shall include pre-operation and project operation. The plan shall establish pre-well-construction groundwater level trends that can be quantitatively compared against predicted trends near the project pumping wells and near potentially impacted receptors.

A. Prior to Project Construction

1. A well reconnaissance shall be conducted to investigate and document the condition of existing water supply wells located within 3 miles of the project site, provided that access is granted by the well owners. The reconnaissance shall include sending notices by registered mail to all property owners within a 3 mile radius of the project area, shall identify the owner of each well, and shall include the location, depth, screened interval, pump depth, static water level, pumping water level, and capacity of each well, The plan should include, as feasible, agreements from the owner of each well approving monitoring activities.
2. Monitor to establish pre-installation conditions. The monitoring plan and network of monitoring wells shall make use of existing and new monitoring wells installed by the project owner. All monitoring wells shall be installed to a depth that matches the depth of the project pumping wells. A plan for design and construction of any new monitoring wells and how they will be effective in evaluating project pumping impacts on domestic well owners shall be submitted to the CPM for review and approval prior to installation and monitoring.

   The projected area of groundwater drawdown shall be refined on an annual basis during project construction and every year during project operations using the data acquired through implementation of this condition.
3. As access allows, measure groundwater levels from the off-site and on-site wells within the network and background wells to provide initial groundwater levels for pre-project trend analysis. Assess the significance of an apparent trend and estimate the magnitude of that trend using the Kendall test for trend (Kendall and Kendall, 1980) and the Sen’s slope estimator (Sen, 1968).

B. During Construction:

1. Collect water levels from wells within the monitoring network on a monthly basis throughout the construction period and at the end of the construction period. Perform statistical trend analysis for water levels. Assess the significance of an apparent trend and estimate the magnitude of that trend using the Kendall test for trend (Kendall and Kendall, 1980) and the Sen's slope estimator (Sen, 1968).

C. During Operation:

1. On a monthly basis for the first year of operation and quarterly thereafter for the life of the project, collect water level measurements from wells identified in the groundwater monitoring program to evaluate operational influence from the project. Operational parameters (i.e., pumping rate) of the water supply wells shall be monitored.
2. On an annual basis, perform statistical trend analysis of water level data and compare to predicted water level declines due to project pumping. Analysis of the significance of an apparent trend shall be determined and the magnitude of that trend estimated. Assess the significance of an apparent trend and estimate the magnitude of that trend using the Kendall test for trend (Kendall and Kendall, 1980) and the Sen's slope estimator (Sen, 1968).
3. If water levels have been lowered more than 15 feet below preconstruction levels at the nearest determined neighboring well, and monitoring data provided by the project owner show these water level changes are different from background trends and are caused by project pumping, then the project owner shall provide mitigation to the impacted well owner(s). Mitigation shall be provided to the impacted well owners that experience 15 feet or more of project-induced drawdown if the CPM's inspection of the well monitoring data confirms changes to water levels and water level trends relative to measured pre-project water levels, and the well (private owner's well in question) yield or performance has been significantly affected by project pumping. The type and extent of mitigation shall be determined by the amount of water level decline induced by the project, the type of impact, and site specific well construction and water use characteristics. If an impact is determined to be caused by drawdown from more than one source, the level of mitigation provided shall be proportional to the amount of drawdown induced by the project relative to other sources. In order to be eligible, a well owner must provide documentation of the well location and construction, including pump intake depth, and that the well was constructed and usable before project pumping was initiated. The mitigation of impacts shall be determined as follows:
    a. If project pumping has lowered water levels by 15 feet or more and increased pumping lifts, increased energy costs shall be calculated. Payment or reimbursement for the increased costs shall be provided at the option of the affected well owner on an

annual basis. In the absence of specific electrical use data supplied by the well owner, the project owner shall use **WATER-2** to calculate increased energy costs.

b. If groundwater monitoring data indicate project pumping has lowered water levels below the top of the well screen, and the well yield is shown to have decreased by 10 percent or more of the pre-project average seasonal yield, compensation shall be provided for the diagnosis and maintenance to treat and remove encrustation from the well screen. Reimbursement shall be provided at an amount equal to the customary local cost of performing the necessary diagnosis and maintenance for well screen encrustation. Should the well yield reductions be recurring, the project owner shall provide payment or reimbursement for periodic maintenance throughout the life of the project. If with treatment the well yield is incapable of meeting 110 percent of the well owner's maximum daily demand, dry season demand, or annual demand, the well owner should be compensated by reimbursement or well replacement as described under Condition 3.c.

c. If project pumping has lowered water levels to significantly impact well yield so that it can no longer meet its intended purpose, causes the well to go dry, or causes casing collapse, payment or reimbursement of an amount equal to the cost of deepening or replacing the well shall be provided to accommodate these effects. Payment or reimbursement shall be at an amount equal to the customary local cost of deepening the existing well or constructing a new well of comparable design and yield (only deeper). The demand for water, which determines the required well yield, shall be determined on a per well basis using well owner interviews and field verification of property conditions and water requirements compiled as part of the pre-project well reconnaissance. Well yield shall be considered significantly impacted if it is incapable of meeting 110% of the well owner's maximum daily demand, dry-season demand, or annual demand – assuming the pre-project well yield documented by the initial well reconnaissance met or exceeded these yield levels.

d. The project owner shall notify any owners of the impacted wells within one month of the CPM approval of the compensation analysis for increased energy costs.

e. Pump lowering – In the event that groundwater is lowered as a result of project pumping to an extent where pumps are exposed but well screens remain submerged, the pumps shall be lowered to maintain production in the well. The project owner shall reimburse the impacted well owner for the costs associated with lowering pumps.

f. Deepening of wells – If the groundwater is lowered enough as a result of project pumping that well screens and/or pump intakes are exposed, and pump lowering is not an option, such affected wells shall be deepened or new wells constructed. The project owner shall reimburse the impacted well owner for all costs associated with deepening existing wells or constructing new wells.

4. Groundwater elevations shall be measured throughout the life of the project at least twice per year, and reported to the CPM.
5. If mitigation includes monetary compensation, the project owner shall provide documentation to the CPM that compensation payments have been made by March 31 of each year of project operation or, if lump-sum payments are made, payment is made by March 31 following the first year of operation only. Within 30 days after compensation is paid, the project owner shall submit to the CPM a compliance report describing compensation for increased energy costs necessary to comply with the provisions of this condition.
6. At the end of every subsequent five-year monitoring period, the collected data shall be evaluated by the CPM who will determine if the sampling frequency should be revised or eliminated.
7. During the life of the project, the project owner shall provide to the CPM all monitoring reports, complaints, studies and other relevant data within 10 days of being received by the project owner.

Verification: The project owner shall do all of the following:

- At least 60 days prior to operation of the site groundwater supply wells, the project owner shall submit to the CPM a comprehensive report presenting all the data and information required in item A. 1. above. The project owner shall submit to the CPM a report showing the results of the well reconnaissance, conditions of existing wells that will be used to evaluate potential project pumping impacts, and all calculations, assumptions, well logs, and reports made in development of the report data and interpretations.
- At least 180 days prior to project construction the project owner shall submit a plan showing the proposed design and construction of the new monitoring well network and existing wells that will be used to evaluate potential impacts to domestic well owners. The plan will include well design and installation methods.
- During project construction, the project owner shall submit to the CPM quarterly reports presenting all the data and information required in item B above. The quarterly reports shall be provided 30 days following the end of the quarter. The project owner shall also submit to the CPM all calculations and assumptions made in development of the report data and interpretations.
- No later than March 31 of each year of construction or 60 days prior to project operation, the project owner shall provide to the CPM for review and approval, documentation showing that any mitigation to private well owners during project

construction was satisfied, based on the requirements of the property owner as determined by the CPM.

- During project operation, the project owner shall submit to the CPM applicable quarterly, semi-annual and annual reports presenting all the data and information required in item C above. Quarterly reports shall be submitted to the CPM 30 days following the end of the quarter. The fourth quarter report shall serve as the annual report and shall be provided on January 31 in the following year. The project owner shall submit to the CPM all calculations and assumptions made in development of report data and interpretations, calculations, and assumptions used in development of any reports.

After the first five year operational and monitoring period, the project owner shall submit a 5-year monitoring report to the CPM that includes all monitoring data collected and a summary of the findings. The CPM will determine if the water level measurements and sampling frequencies should be revised.

GROUNDWATER PUMPING COST CALCULATION

WATER-2: Where it is determined that the project owner shall reimburse a private well owner for increased energy costs identified as a result of analysis performed in Condition of Certification **WATER-1,** the project owner shall calculate the compensation owed to any owner of an impacted well as described below.

Increased cost for energy =	change in lift/total system head x total energy consumption x costs/unit of energy

Where:

change in lift (ft) =	calculated change in water level in the well resulting from project
total system head (ft) =	elevation head + discharge pressure head
elevation head (ft) =	difference in elevation between wellhead discharge pressure gauge and water level in well during pumping.
discharge pressure head (ft) =	pressure at wellhead discharge gauge (psi) X 2.31

The project owner shall submit to the CPM for review and approval the documentation showing which well owners must be compensated for increased energy costs and that the proposed amounts are sufficient compensation to comply with the provisions of this condition.

- Any reimbursements (either lump sum or annual) to impacted well owners shall be only to those well owners whose wells were in service within six months of the Commission decision and within a 3-mile radius of the project site.
- The project owner shall notify all owners of the impacted wells within one month of the CPM approval of the compensation analysis for increased energy costs.
- Compensation shall be provided on either a one-time lump-sum basis, or on an annual basis, as described below.

Annual Compensation: Compensation provided on an annual basis shall be calculated prospectively for each year by estimating energy costs that will be incurred to provide the additional lift required as a result of the project. With the permission of the impacted well owner, the project owner shall provide energy meters for each well or well field affected by the project. The impacted well owner, to receive compensation, must provide documentation of energy consumption in the form of meter readings or other verification of fuel consumption. For each year after the first year of operation, the project owner shall include an adjustment for any deviations between projected and actual energy costs for the previous calendar year.

One-Time Lump-Sum Compensation: Compensation provided on a one-time lump-sum basis shall be based on a well-interference analysis, assuming the maximum project-pumping rate of 7,500 acre-feet per year. Compensation associated with increased pumping lift for the life of the project shall be estimated as a lump sum payment as follows:

- The current cost of energy to the affected party considering time of use or tiers of energy cost applicable to the party's billing of electricity from the utility providing electric service, or a reasonable equivalent if the party independently generates their electricity;
- An annual inflation factor for energy cost of 3 percent; and
- A net present value determination assuming a term of 30 years and a discount rate of 9 percent.

Verification: The project owner shall do all of the following:

1. No later than 30 days after CPM approval of the well drawdown analysis, the project owner shall submit to the CPM for review and approval all documentation and calculations describing necessary compensation for energy costs associated with additional lift requirements.
2. The project owner shall submit to the CPM all calculations, along with any letters signed by the well owners indicating agreement with the calculations, and the name and phone numbers of those well owners that do not agree with the calculations. Compensation payments shall be made by March 31 of each year of project operation or, if lump-sum payment is selected, payment shall be made by March 31 of the first year of operation only. Within 30 days after compensation is paid, the project owner shall submit to the CPM a compliance report describing compensation for increased energy costs necessary to comply with the provisions of this condition.

CONSTRUCTION AND OPERATIONS WATER USE

WATER-4: The proposed project's use of groundwater for all construction activities shall not exceed 12 acre-feet per year of construction. The proposed project's use of groundwater for all operations and domestic use activities shall not exceed 7,500 acre-feet per year or the reduced volume that may be identified as a result of the alternatives analysis.

Prior to the use of groundwater for construction, the project owner shall install and maintain metering devices as part of the water supply and distribution system to document project water use and to monitor and record in gallons per month the total volume(s) of water supplied to the project from this water source. The metering devices shall be of an adequate design for the intended use and shall be operational for the life of the project. Metering devices shall be calibrated and maintained in accordance with the manufacturer's recommended procedures and schedule.

Verification: Beginning six (6) months after the start of construction, the project owner shall prepare a semi-annual summary report of the amount of water used for construction purposes. The summary shall include the monthly water usage in gallons. The report shall also include photographs and documentation showing the type of meter selected and installed condition.

The project owner shall prepare an annual summary report, which shall include daily usage, monthly range and monthly average of daily water usage in gallons per day, and total water used on a monthly and annual basis in acre-feet by source. For years subsequent to the initial year of operation, the annual summary report shall also include the yearly range and yearly average water use by source. For calculating the total water use, the term "year" shall correspond to the date established for the annual compliance report submittal. The report shall also include reports on meter calibration and maintenance, and document that the meter is in working order.

PROJECT GROUNDWATER WELLS

WATER-5 Pre-Well Installation. The project owner proposes to construct and operate groundwater production wells that will produce water from the Kern County Subbasin. The project owner shall ensure that the wells are completed in accordance with all applicable state and local water well construction permits and requirements. Prior to initiation of well construction activities, the project owner shall submit for review and comment a well construction packet to the Kern County Environmental Health Services Department and fees normally required for the county's well permit, with copies to the CPM for review and approval. The project shall not construct a well or extract and use groundwater until the CPM provides approval to construct and operate the well.

POST-WELL INSTALLATION. The project owner shall provide documentation to the CPM that the well has been properly completed. In accordance with California's Water Code section 13754, the driller of the well shall submit to the DWR a Well Completion Report for each well installed. The project owner shall ensure the Well Completion reports are submitted. The project owner shall ensure compliance with all county water well standards and requirements for the life of the wells and shall provide the CPM with two (2) copies each of all monitoring or other reports required for compliance with the Kern County Environmental Health Services Department water well standards and operation requirements, as well as any changes made to the operation of the well.

Verification: The Project owner shall do all of the following:

A. No later than sixty (60) days prior to the construction of the onsite groundwater production wells, the project owner shall submit to the CPM for review and approval a copy of the water well construction packet submitted to the Kern County Environmental Health Services Department.

B. No later than thirty (30) days prior to the construction of the onsite groundwater production wells, the project owner shall submit a copy of written concurrence received from the Kern County Environmental Health Services Department that the proposed well construction activities comply with all county well requirements and meet the requirements established by the county's water well permit program.

C. No later than sixty (60) days after installation of each well at the project site, the project owner shall ensure that the well driller submits a Well Completion Report to the DWR with a copy provided to the CPM. The project owner shall submit to the CPM, together with the Well Completion Report, a copy of well drilling logs, water quality analyses, and any inspection reports.

D. During well construction and for the operational life of the well, the project owner shall submit two (2) copies each to the CPM of any proposed well construction or operation permit changes within ten (10) days of submittal to or receipt from the Kern County Environmental Health Services Department.

E. No later than fifteen (15) days after completion of the onsite groundwater production wells, the project owner shall submit proof of well completion documentation to the CPM, and the CVRWQCB that well drilling activities were conducted in compliance with Title 23, California Code of Regulations, Chapter 15, Discharges of Hazardous Wastes to Land, (23 CCR, sections 2510 et seq.) requirements and that any onsite drilling sumps used for project drilling activities were removed in compliance with 23 CCR section 2511(c).

GROUND SUBSIDENCE MONITORING AND ACTION PLAN

WATER–6 The project owner shall construct one monument monitoring station per production well or a minimum of three stations to measure potential inelastic subsidence that may affect structures near the proposed production wells, including the California Aqueduct. The project owner shall:

A. Prepare and submit a Subsidence Monitoring Plan (SMP), including all calculations and assumptions. The plan shall include the following elements:

1. Construction diagrams of the proposed monument monitoring stations including size and description, planned depth, measuring points, and protection measures;
2. Map depicting locations (minimum of three) of the planned monument monitoring stations;
3. Monitoring program that includes monitoring frequency and reporting format.

B. Prepare annual reports commencing three (3) months following commencement of groundwater production during construction and operations. The reports shall include presentation and interpretation of the data collected including comparison to the requirements and actions taken to comply with the elements developed in Item C.

C. Prepare a Mitigation Action Plan that details the following:

1. How subsidence shall not be allowed to damage existing structures either on or off the site or alter the appearance or use of the structure;
2. How to avoid subsidence that may alter natural drainage patterns or permit the formation of lakes;
3. If any subsidence violates (a) or (b), the project owner shall investigate the need to immediately modify or cease pumping for project operations until the cause is interpreted and subsidence caused by project pumping abates and the structures and/or drainage patterns are stabilized and corrected.

The project owner shall submit the Ground Subsidence Monitoring and Action Plan, prepared by an Engineering Geologist or Geotechnical Engineer registered in the State of California, thirty (30) days prior to the start of extraction of groundwater for construction or operation.

Verification: The project owner shall do all of the following:

1. At least thirty (30) days prior to project construction, the project owner shall submit to the CPM a comprehensive report presenting all the data and information required in item A above.
2. During project construction and operations, the project owner shall submit to the CPM quarterly reports presenting all the data and information required in item B above.
3. The project owner shall submit to the CPM all calculations and assumptions made in development of the report data and interpretations.

After the first five (5) years of the monitoring period, the project owner shall submit a 5-year monitoring report to the CPM that includes all monitoring data collected and provides a summary of the findings. The CPM shall determine if the Ground Subsidence Monitoring and Action Plan frequencies should be revised, based on project-related consolidation around the well field, when and if it is detected.

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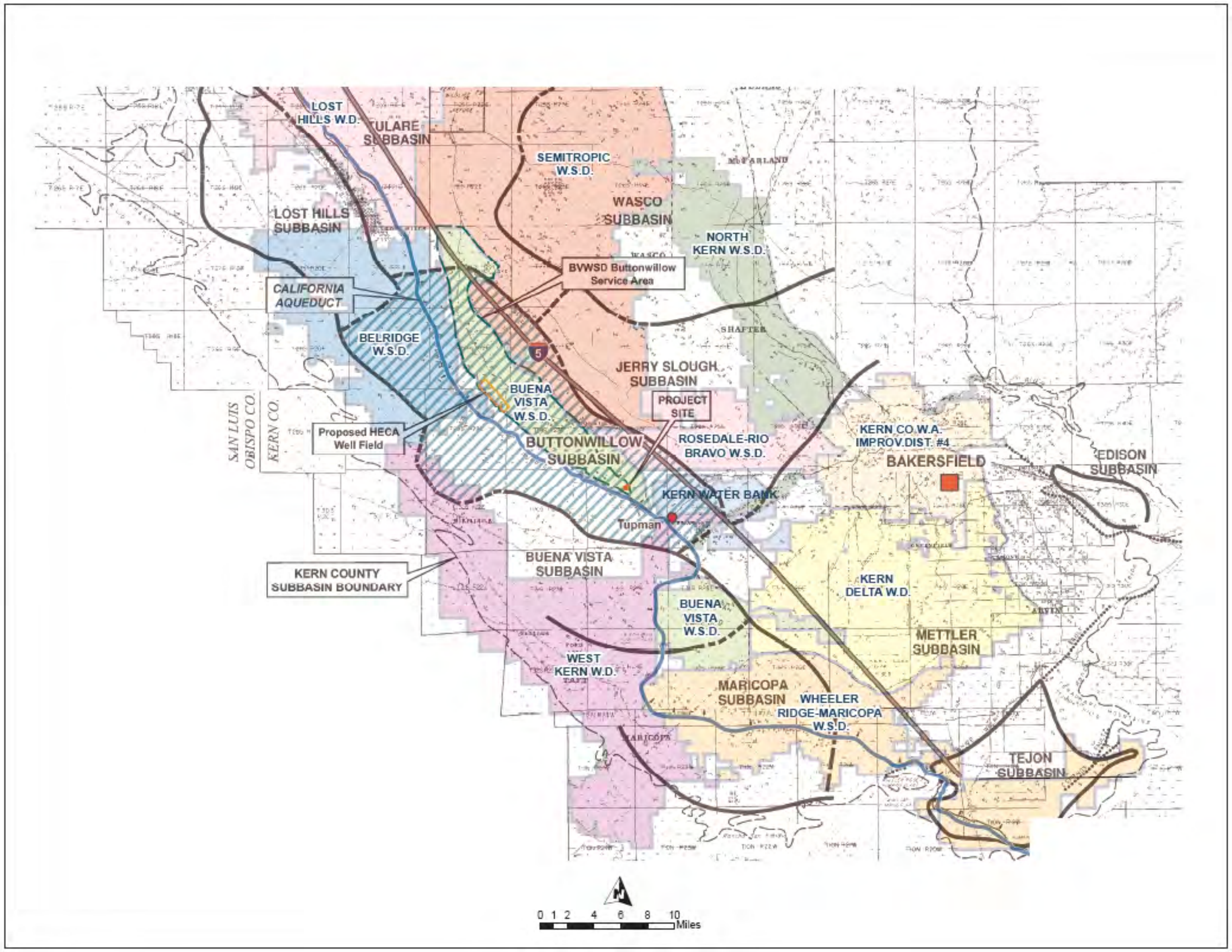
Acronyms Used in the Water Resources Section

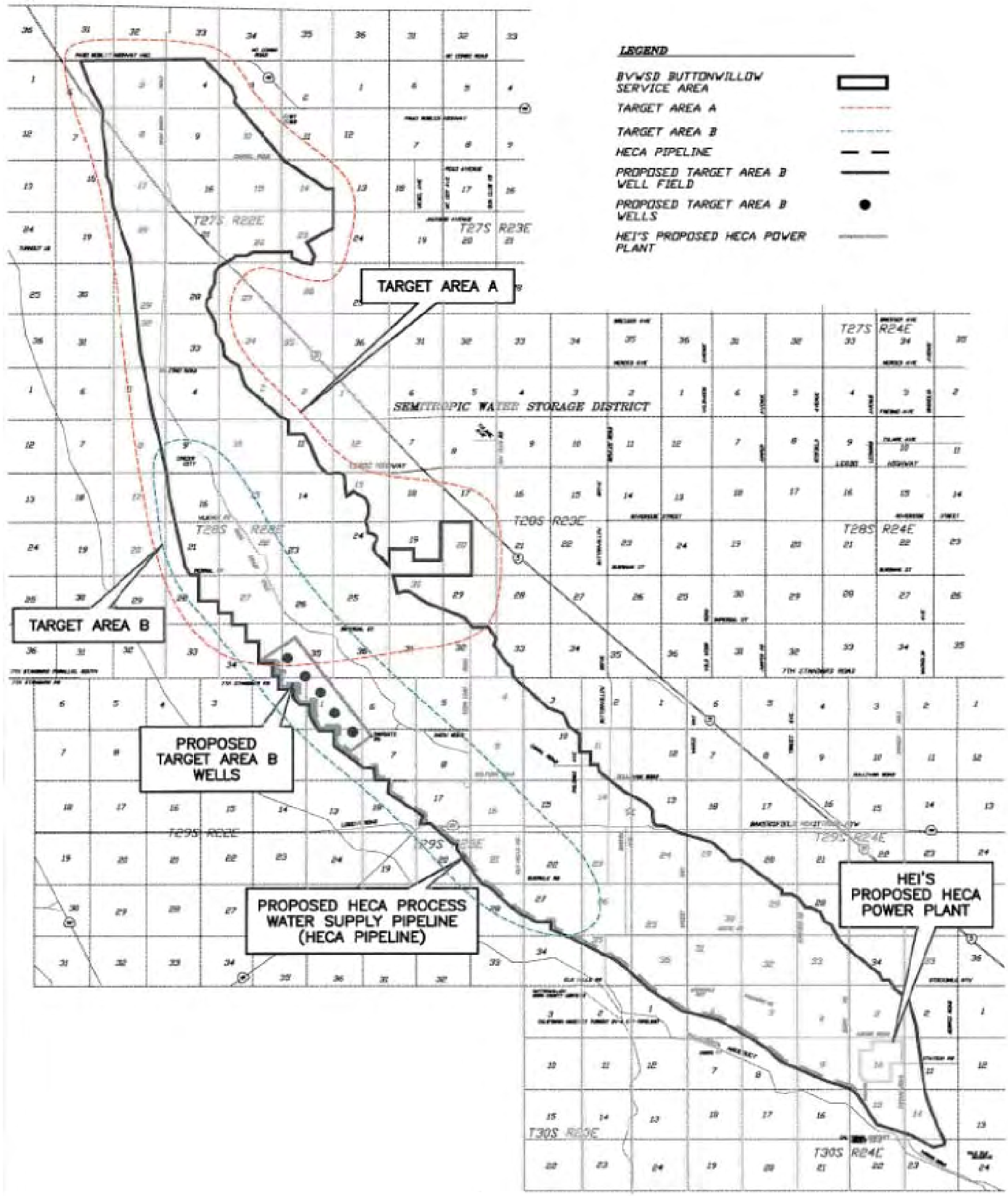
amsl	above mean sea level	**IEPR**	Integrated Energy Policy Report
AF	acre-feet	**lbs**	pounds
AFY	acre-feet per year	**LID**	Low Impact Development
BLM	Bureau of Land Management	**LORS**	laws, ordinances, regulations, and standards
bgs	below ground surface	**MCL**	maximum contaminant level
BMP	Best Management Practices	**mg/l**	milligrams per liter
CDPH	California Department of Public Health	**mph**	miles per hour
CEQA	California Environmental Quality Act	**MOU**	Memorandum of Understanding
cfs	cubic feet per second	**MW**	megawatt
CPM	Compliance Project Manager	**NEPA**	National Environmental Policy Act
DESCP	Drainage, Erosion, and Sediment Control Plan	**NPDES**	National Pollutant Discharge Elimination System
DTSC	Department of Toxic Substances Control	**RCRA**	Resource Conservation and Recovery Act
DWR	Department of Water Resources	**REC**	Recognized Environmental Condition
ESA	Environmental Site Assessment	**ROC**	Record of Conversation
FEMA	Federal Emergency Management Agency	**RWQCB**	Regional Water Quality Control Board
ft/day	feet per day	**SWPPP**	Storm Water Pollution Prevention Plan
fps	feet per second	**SWRCB**	State Water Resources Control Board
FSA	Final Staff Assessment	**TDS**	total dissolved solids
ft/ft	feet per foot	**µS/cm**	microsiemens per centimeter
ft/yr	feet per year	**USCS**	Unified Soil Classification System
gpd	gallons per day	**WWTP**	wastewater treatment plant
gpd/ft	gallons per day per foot		
gpm	gallons per minute		

WATER Figure 1: Kern Water Districts and Inferred Subbasins

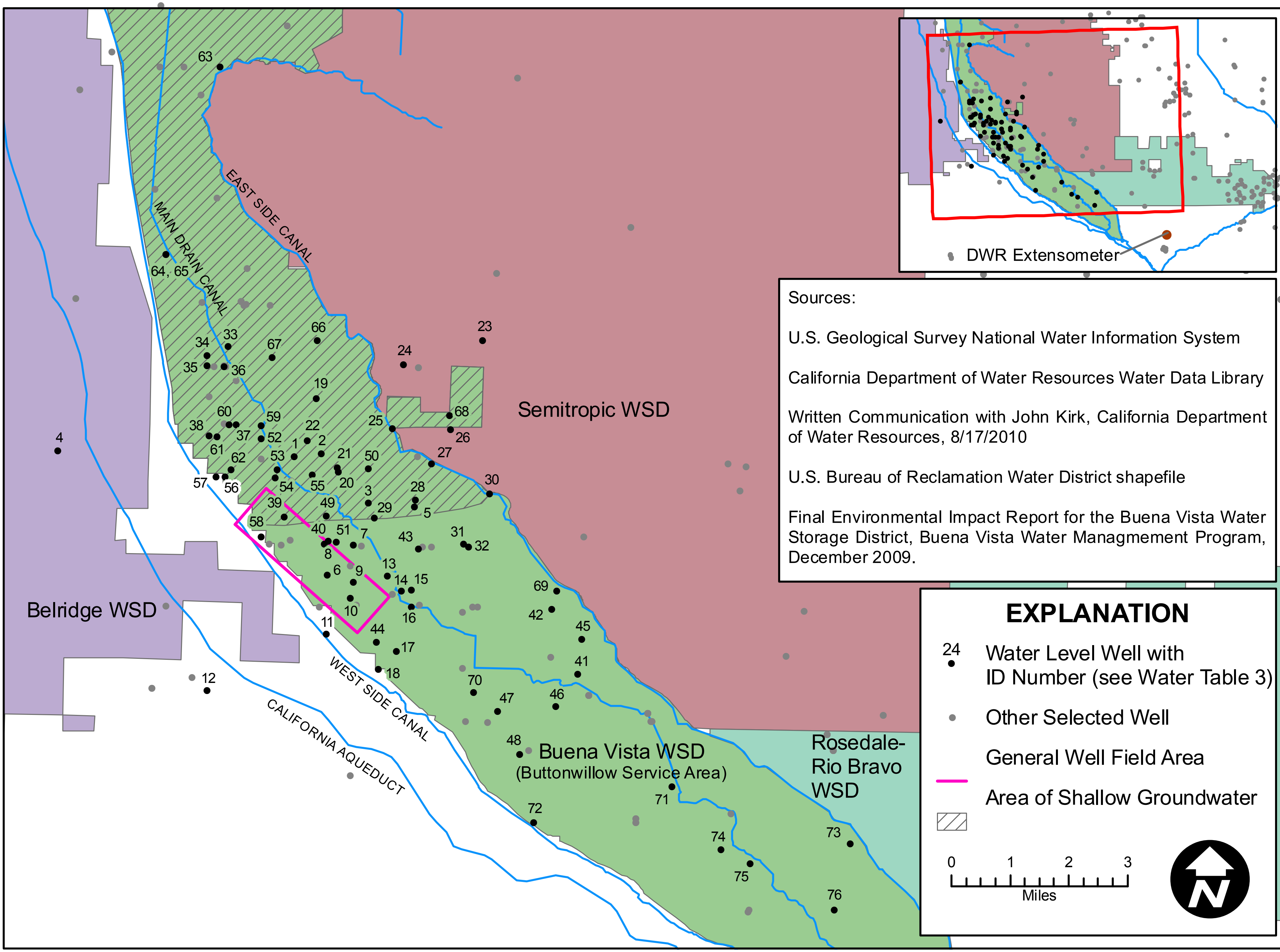


Source: FEIR 2009

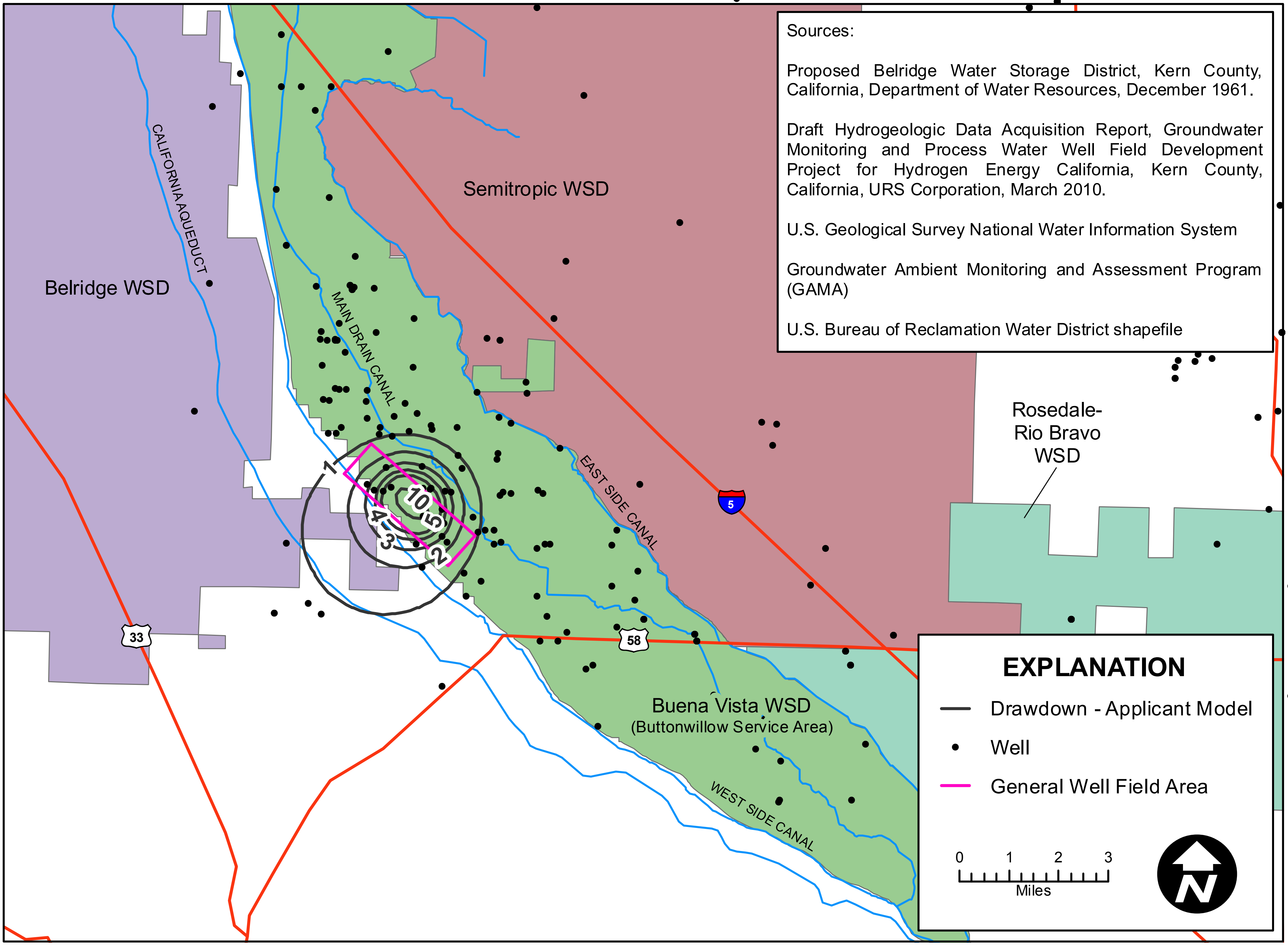
WATER Figure 2: Brackish Groundwater Remediation Project



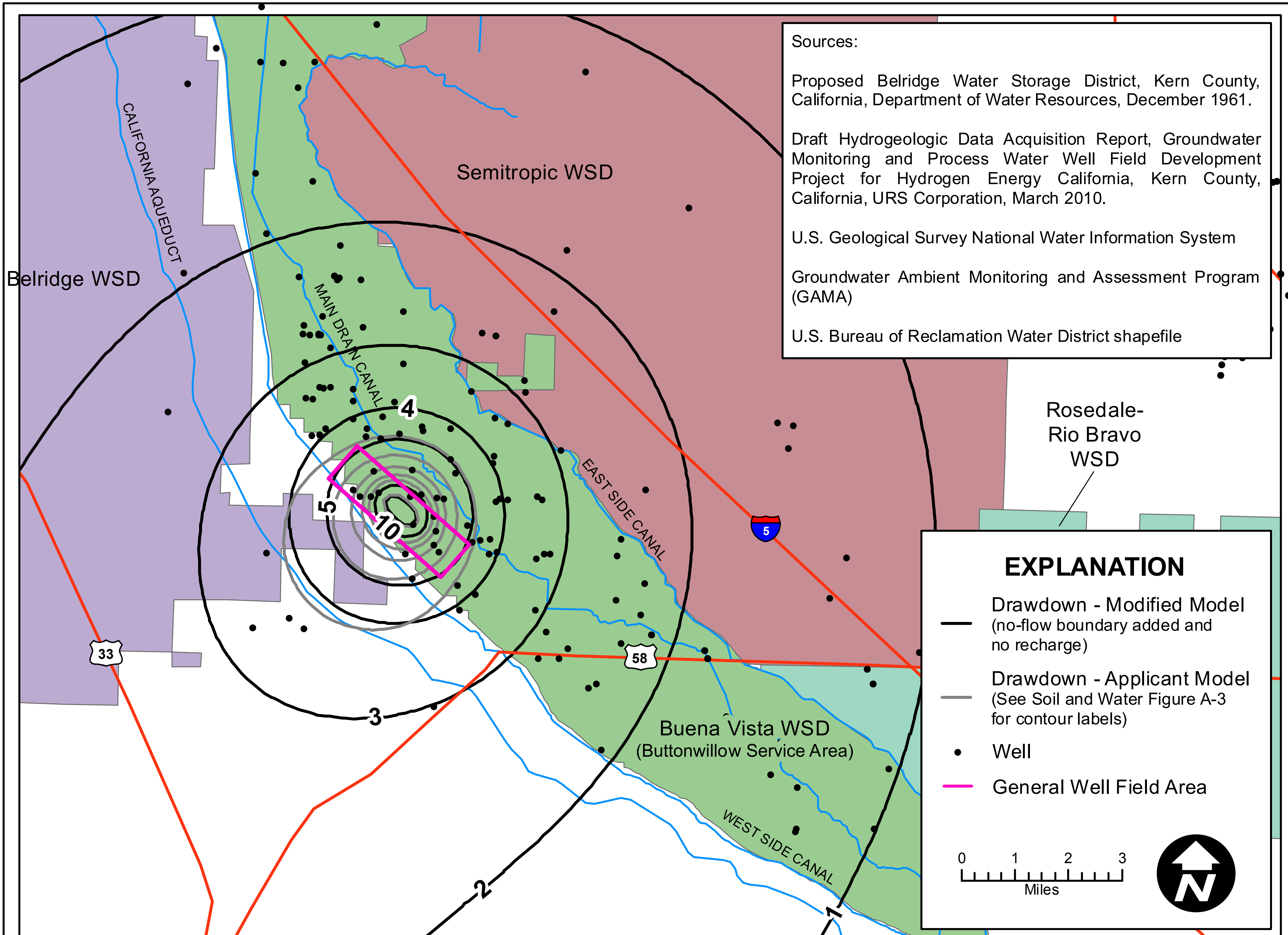
Buttonwillow Service Area



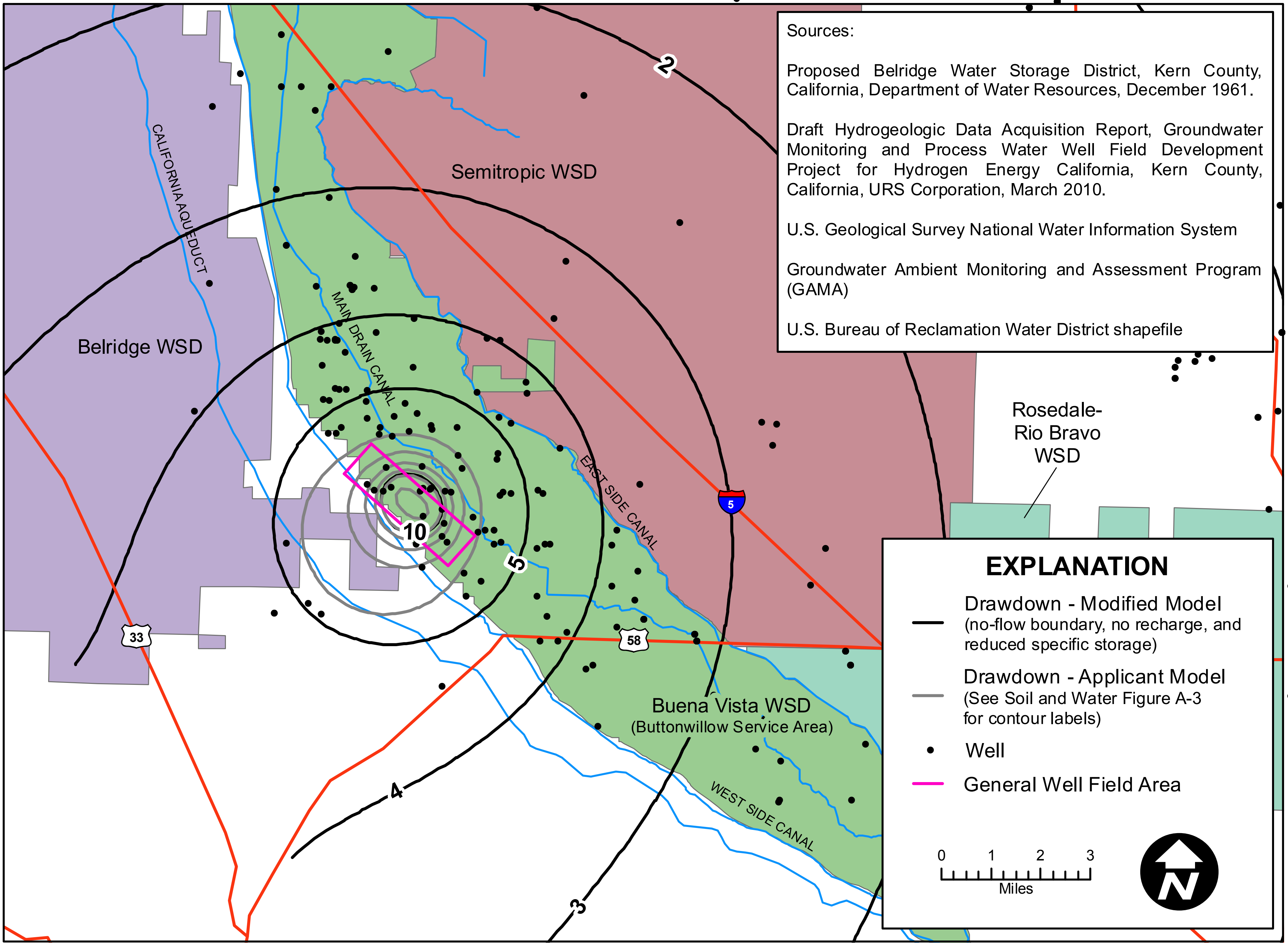
Water Figure 3. Selected existing wells and proposed well field, Buttonwillow Service Area, Buena Vista Water Storage District.



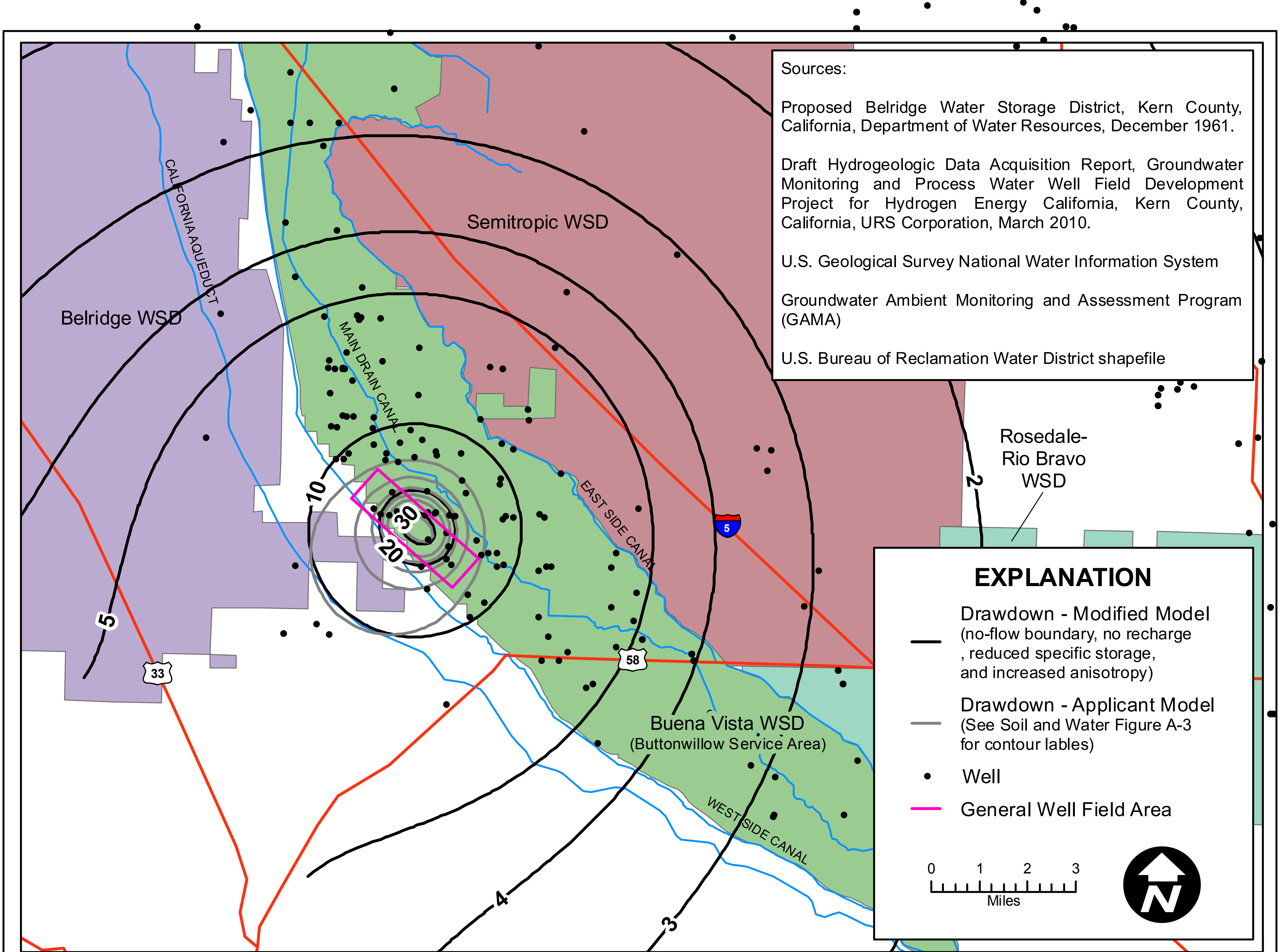
Water Figure 4. Simulated 25-year drawdown from applicant model.



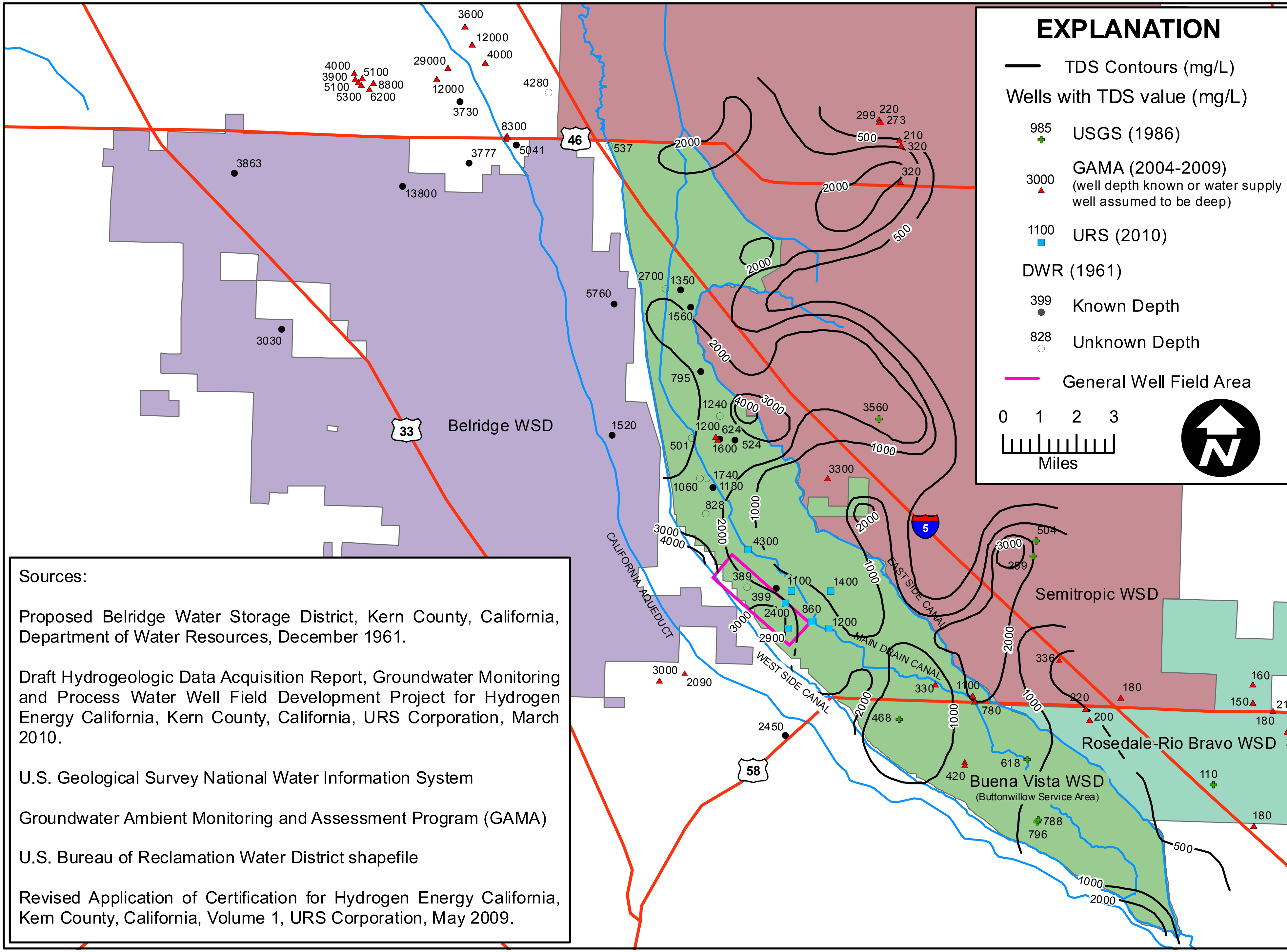
Water Figure 5. Simulated 25-year drawdown from staff modified model (no-flow boundary added and no recharge).



Water Figure 6. Simulated 25-year drawdown from staff-modified model including reduced storativity (0.007).



Water Figure 7. Simulated 25-year drawdown from staff-modified model including reduced storativity (0.007) and anisotropy increased to 1,000.



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Groundwater Ambient Monitoring and Assessment Program (GAMA)

U.S. Bureau of Reclamation Water District shapefile

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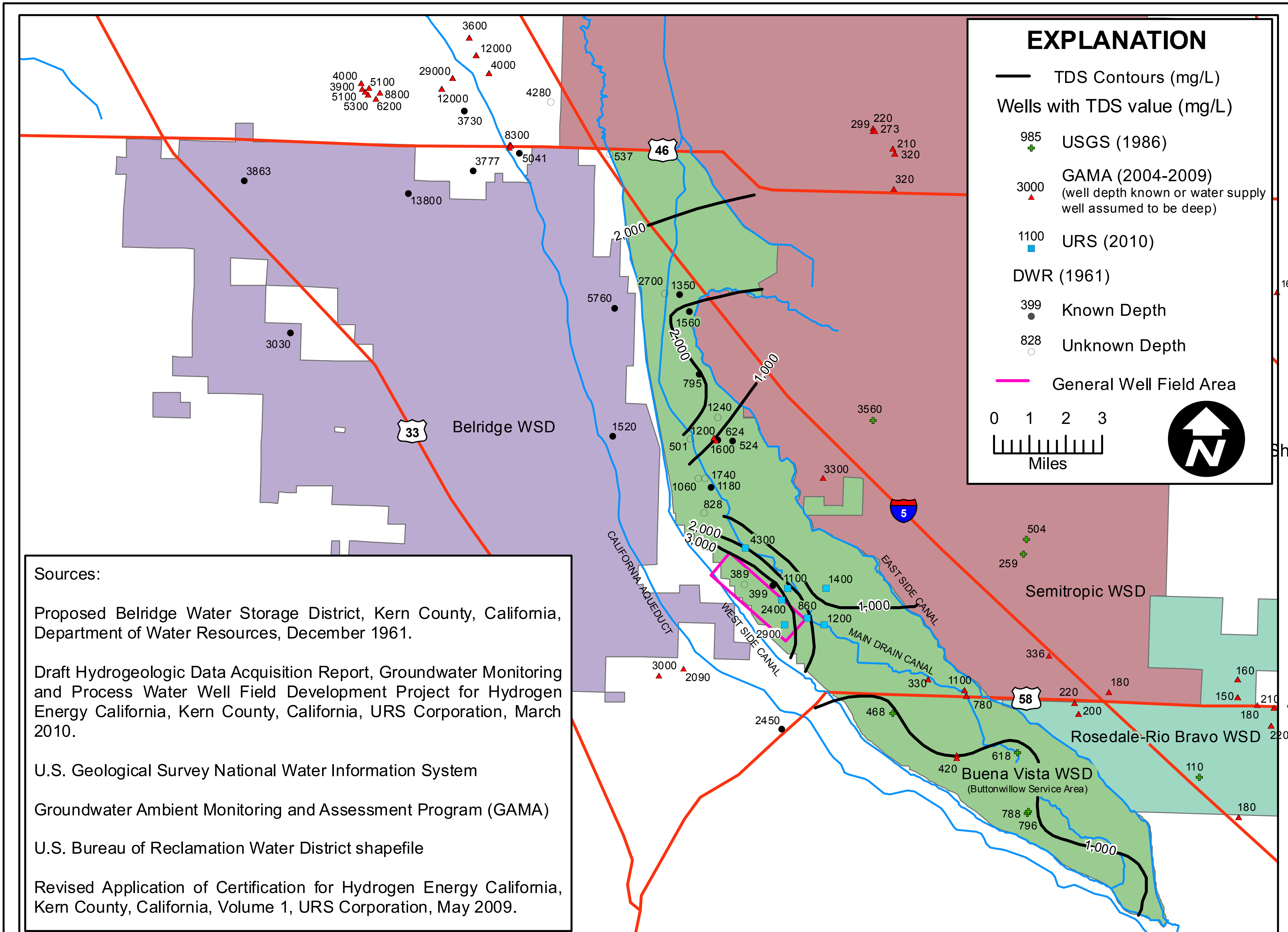
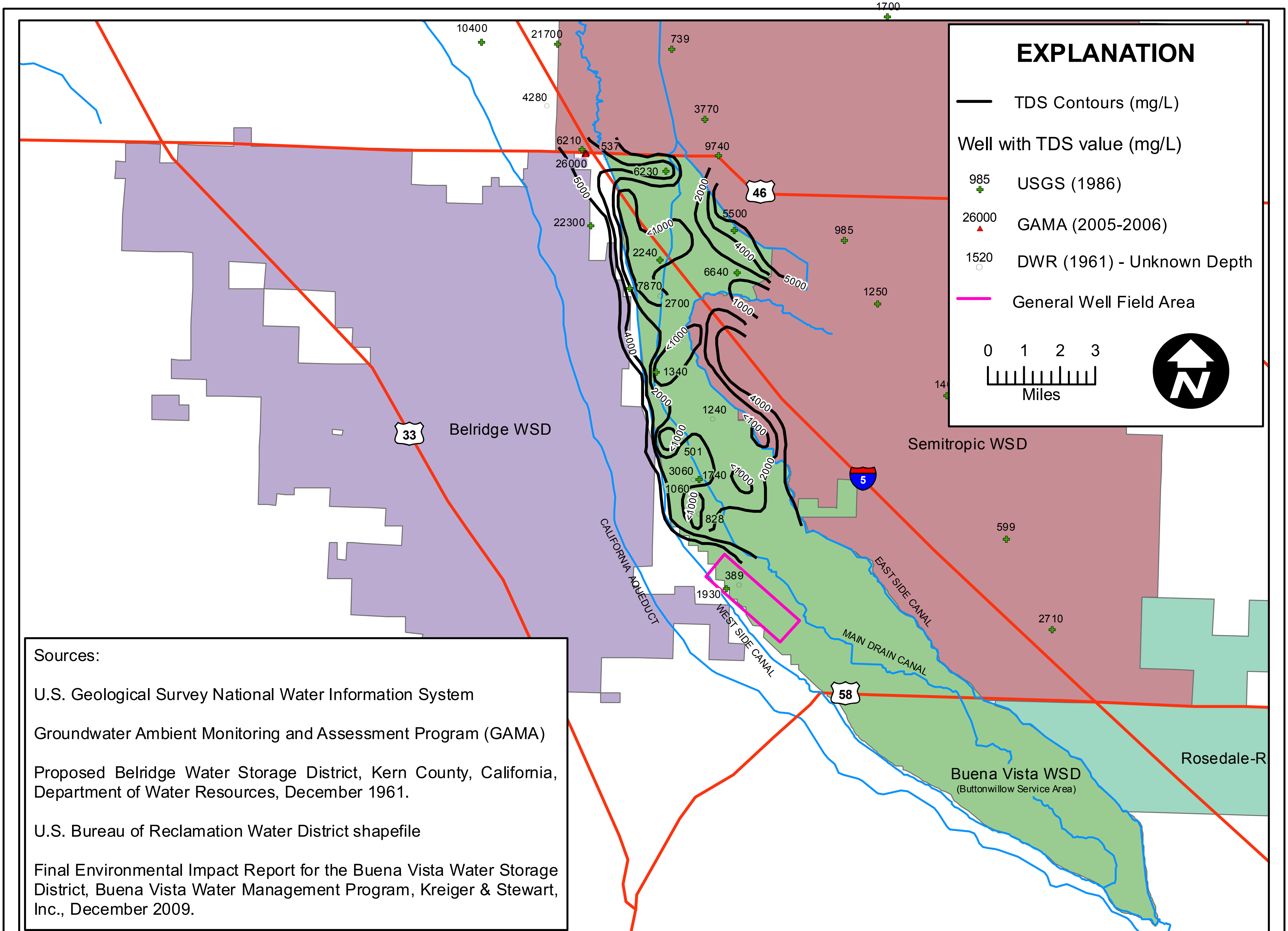
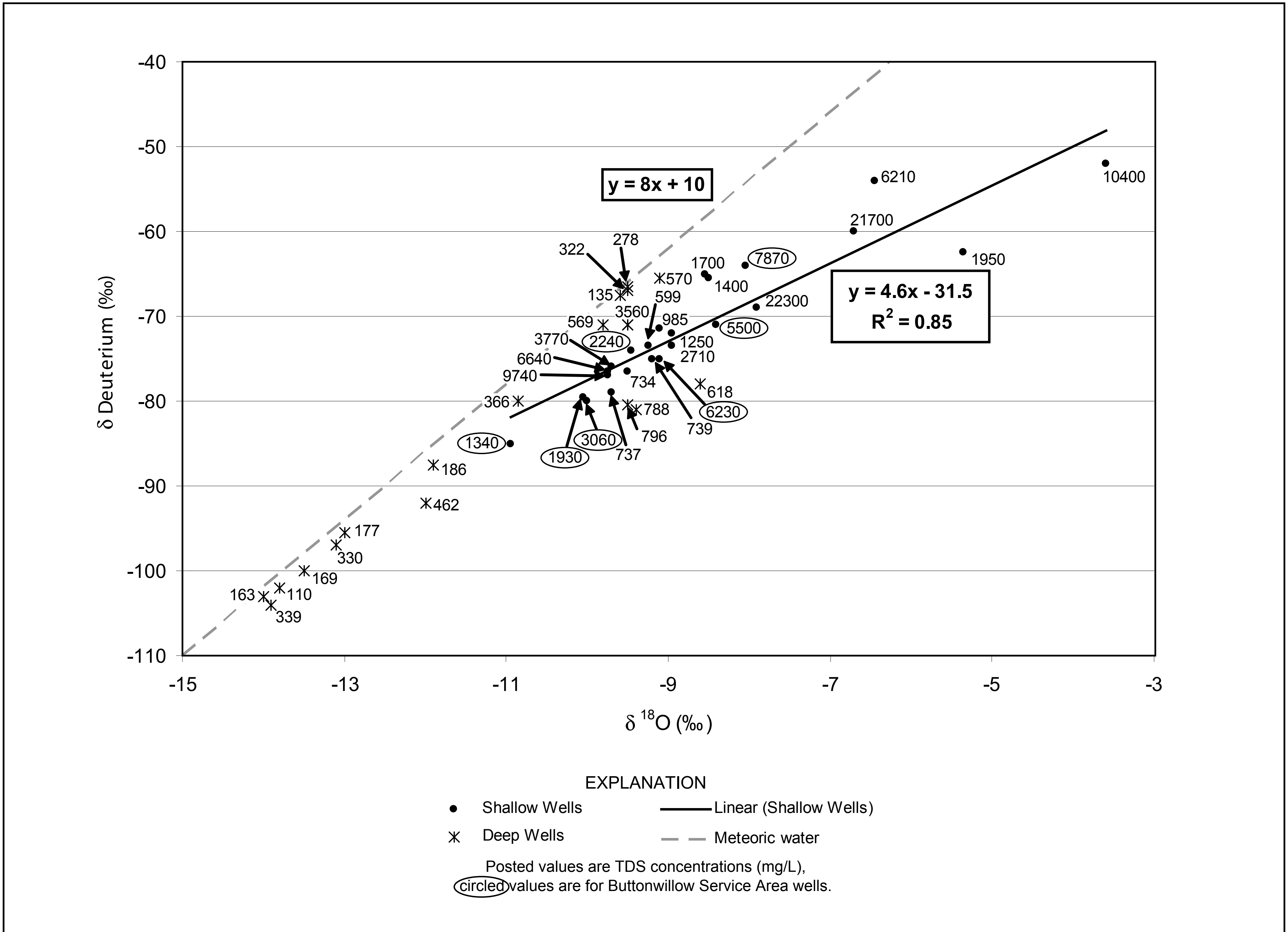
Water Figure 8. Map showing deep TDS concentrations in samples from deep and unknown depth wells and reported 1970-2007 composite TDS concentration contours for the pumped groundwater zone.



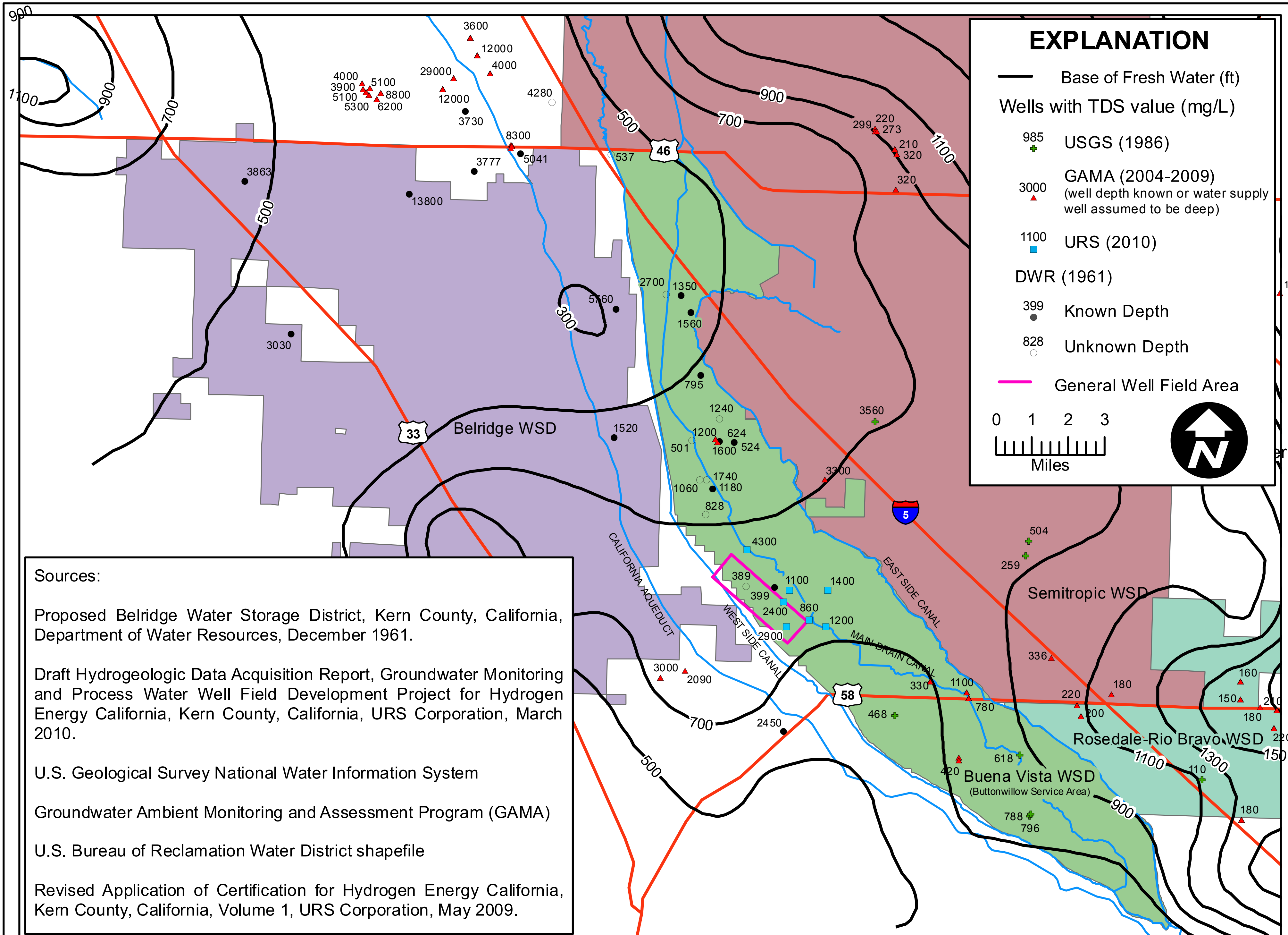
Water Figure 9. Map showing TDS concentrations in samples from deep and unknown depth wells and BVWSD-reported 2001 TDS concentration contours for the pumped groundwater zone.



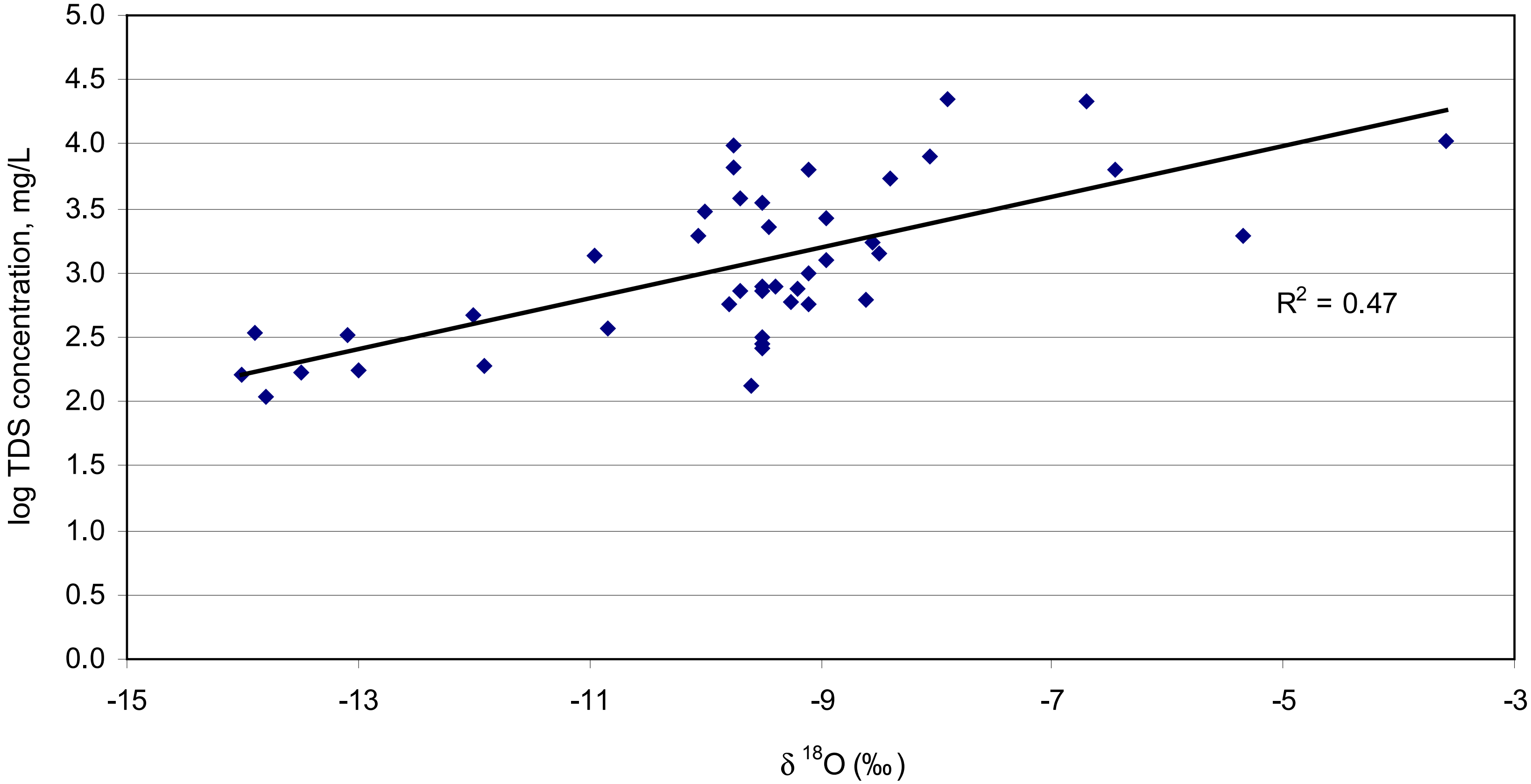
Water Figure 10. Map showing 2008 TDS concentrations in samples from shallow and unknown depth wells and BVWSD-reported concentration contours for the shallow perched aquifer.



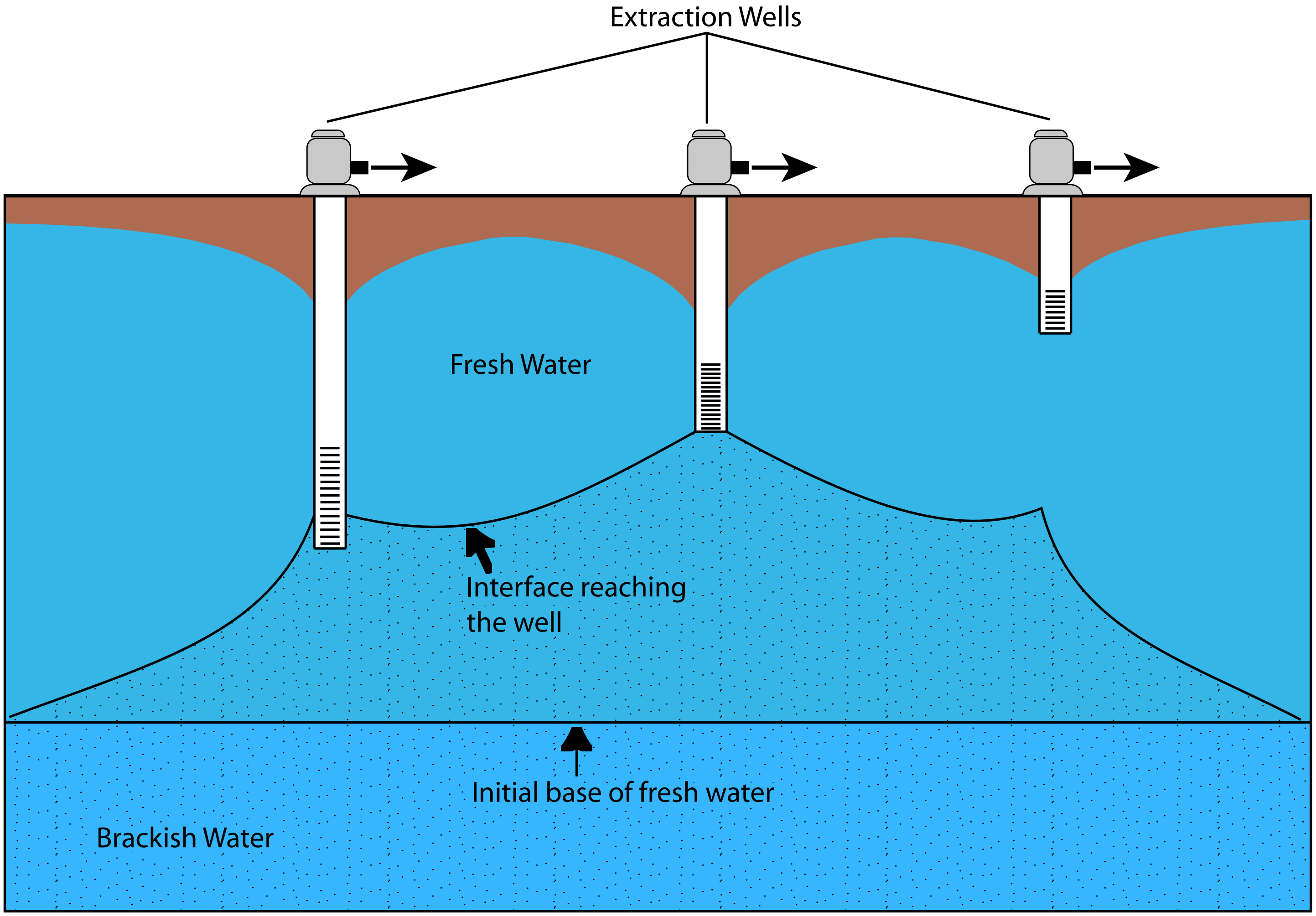
Water Figure 11. Relationships between δD and δ18O, TDS concentrations, and well depths using groundwater data collected by the USGS in 1986.



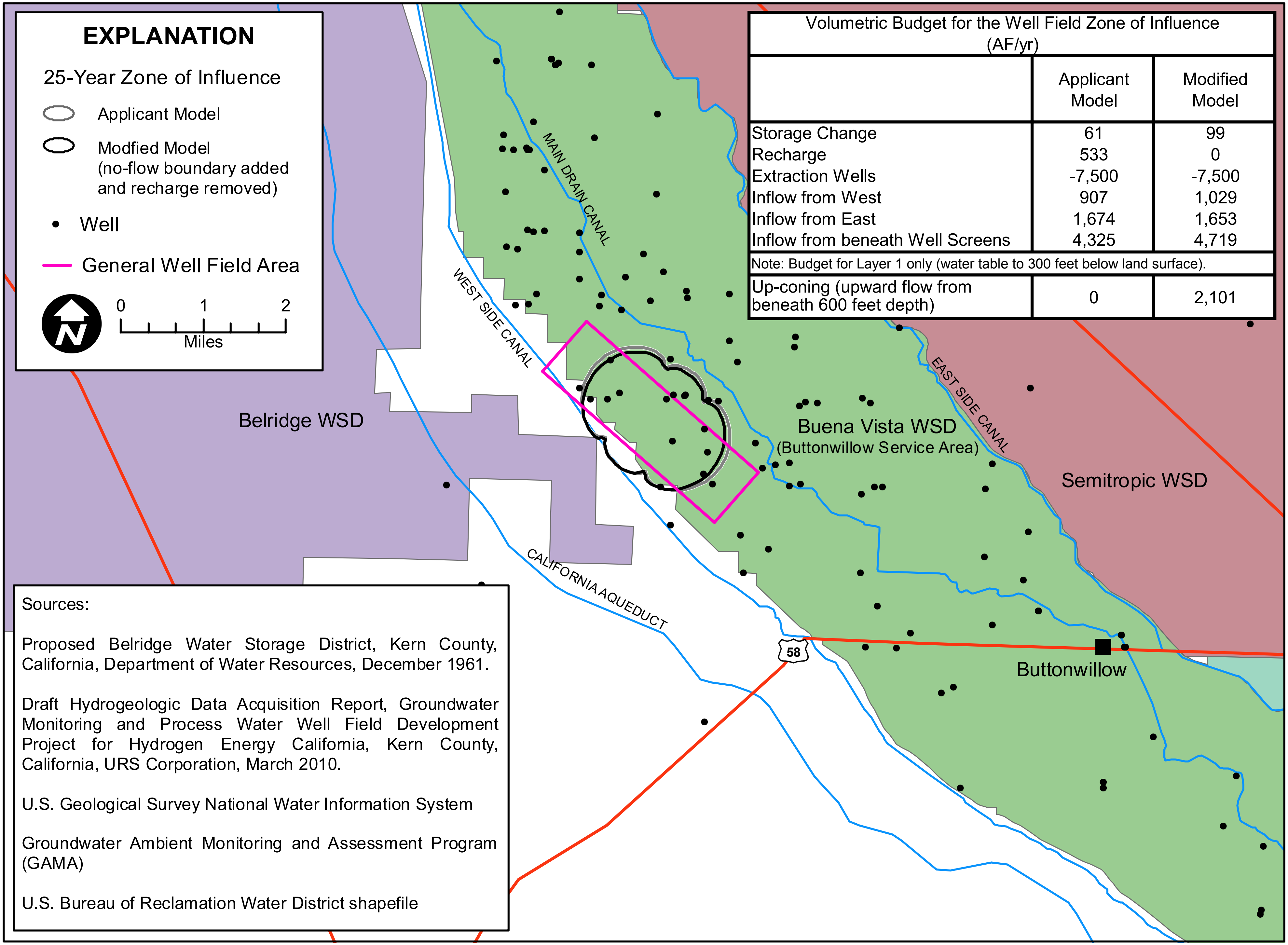
Soil and Water Figure 12. Map showing reported depth to the base of freshwater and TDS concentrations in samples from deep and unknown depth wells.



Water Figure 13. Relationship between TDS concentrations and δ18O fir groundwater samples collected by the USGS in 1986.



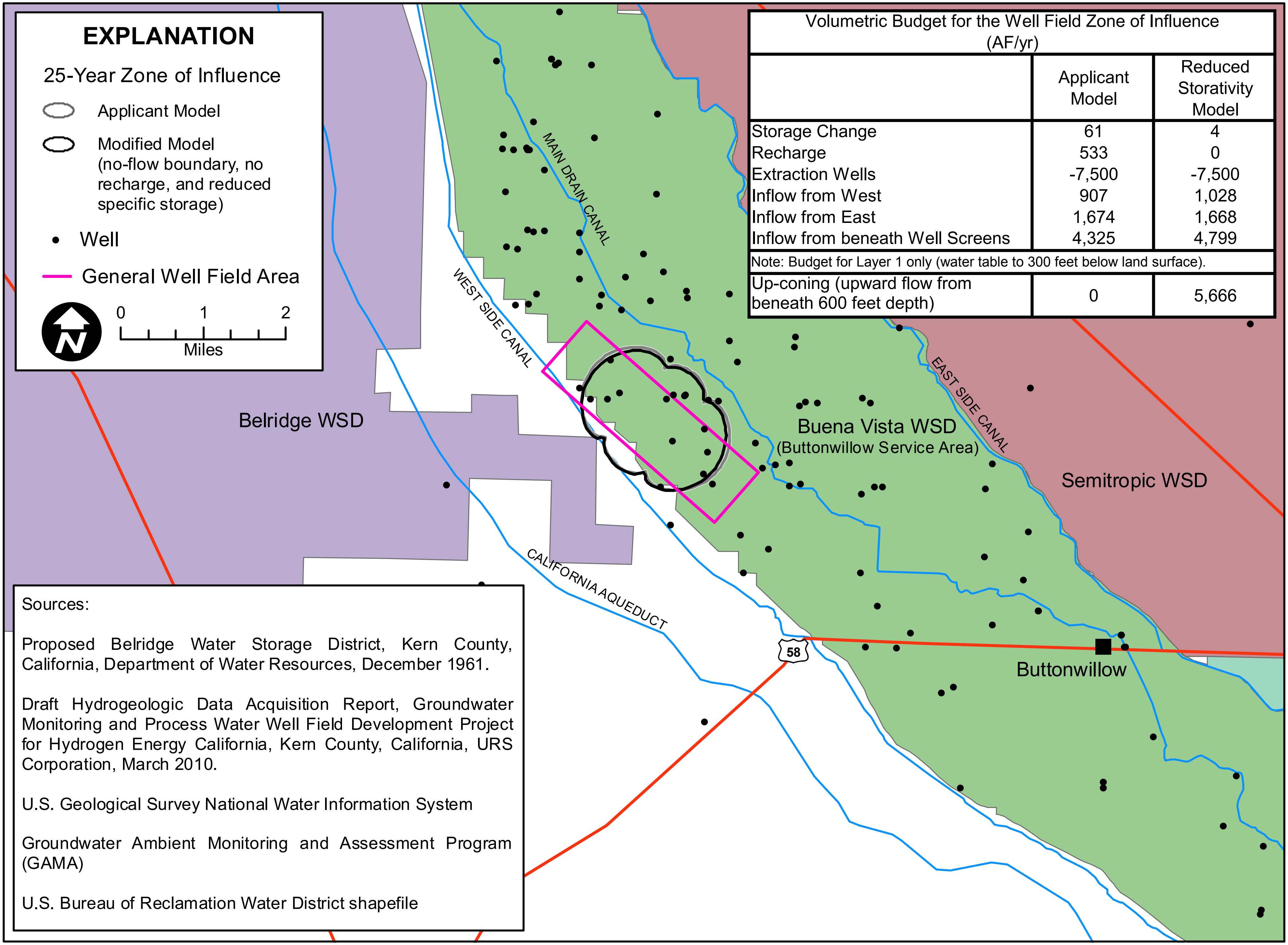
Soil and Water Figure 14. Conceptual illustration of up-coning beneath partially penetrating water supply wells.



Volumetric Budget for the Well Field Zone of Influence (AF/yr)

	Applicant Model	Modified Model
Storage Change	61	99
Recharge	533	0
Extraction Wells	-7,500	-7,500
Inflow from West	907	1,029
Inflow from East	1,674	1,653
Inflow from beneath Well Screens	4,325	4,719
Note: Budget for Layer 1 only (water table to 300 feet below land surface).		
Up-coning (upward flow from beneath 600 feet depth)	0	2,101

Water Figure15- Simulated 25-year Zone of Influence (ZOI) and volumetric budget for the applicant model and staff-modified model (no-flow boundary and no recharge).



Volumetric Budget for the Well Field Zone of Influence (AF/yr)

	Applicant Model	Reduced Storativity Model
Storage Change	61	4
Recharge	533	0
Extraction Wells	-7,500	-7,500
Inflow from West	907	1,028
Inflow from East	1,674	1,668
Inflow from beneath Well Screens	4,325	4,799
Note: Budget for Layer 1 only (water table to 300 feet below land surface).		
Up-coning (upward flow from beneath 600 feet depth)	0	5,666

Sources:

Proposed Belridge Water Storage District, Kern County, California, Department of Water Resources, December 1961.

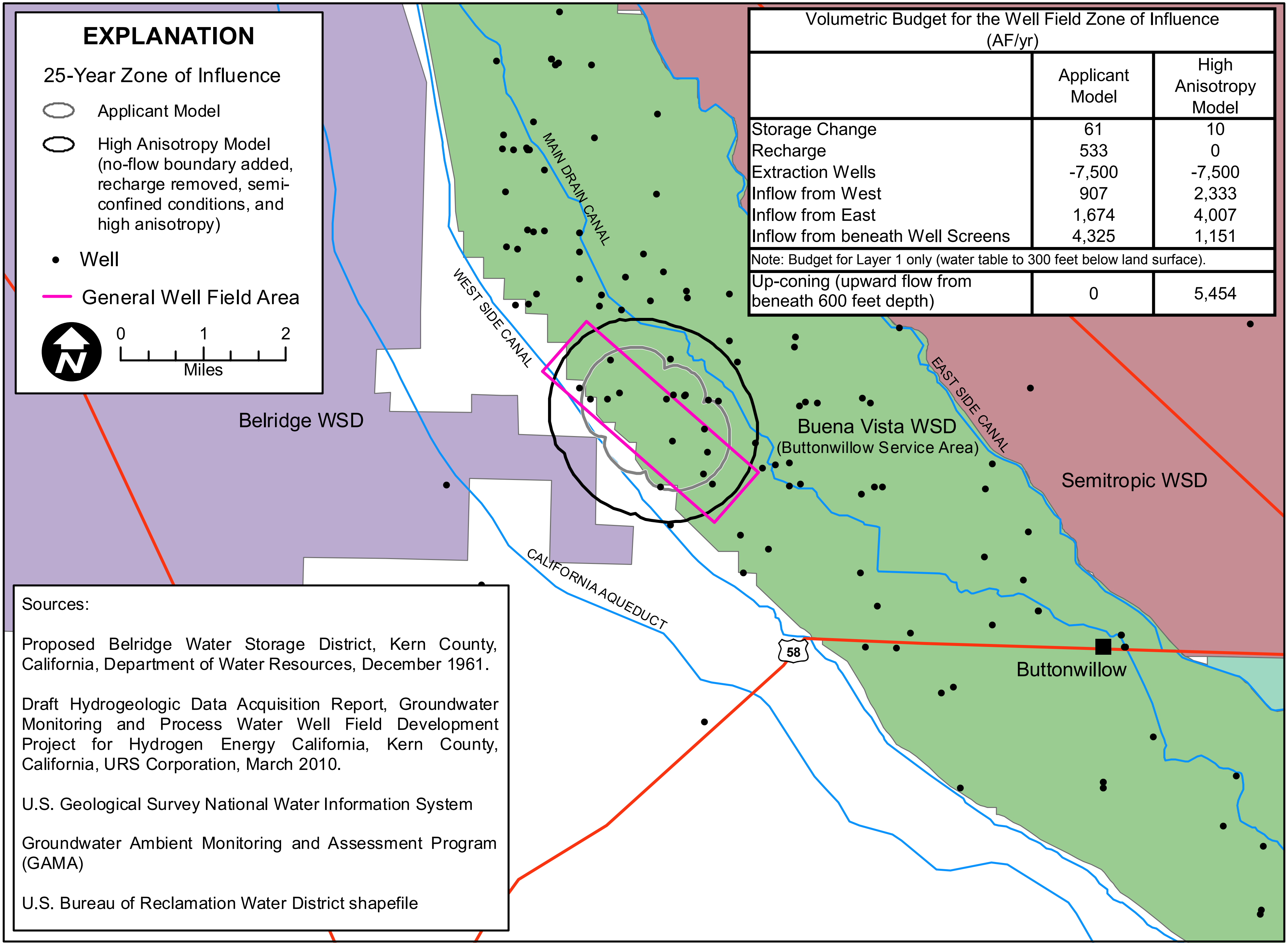
Draft Hydrogeologic Data Acquisition Report, Groundwater Monitoring and Process Water Well Field Development Project for Hydrogen Energy California, Kern County, California, URS Corporation, March 2010.

U.S. Geological Survey National Water Information System

Groundwater Ambient Monitoring and Assessment Program (GAMA)

U.S. Bureau of Reclamation Water District shapefile

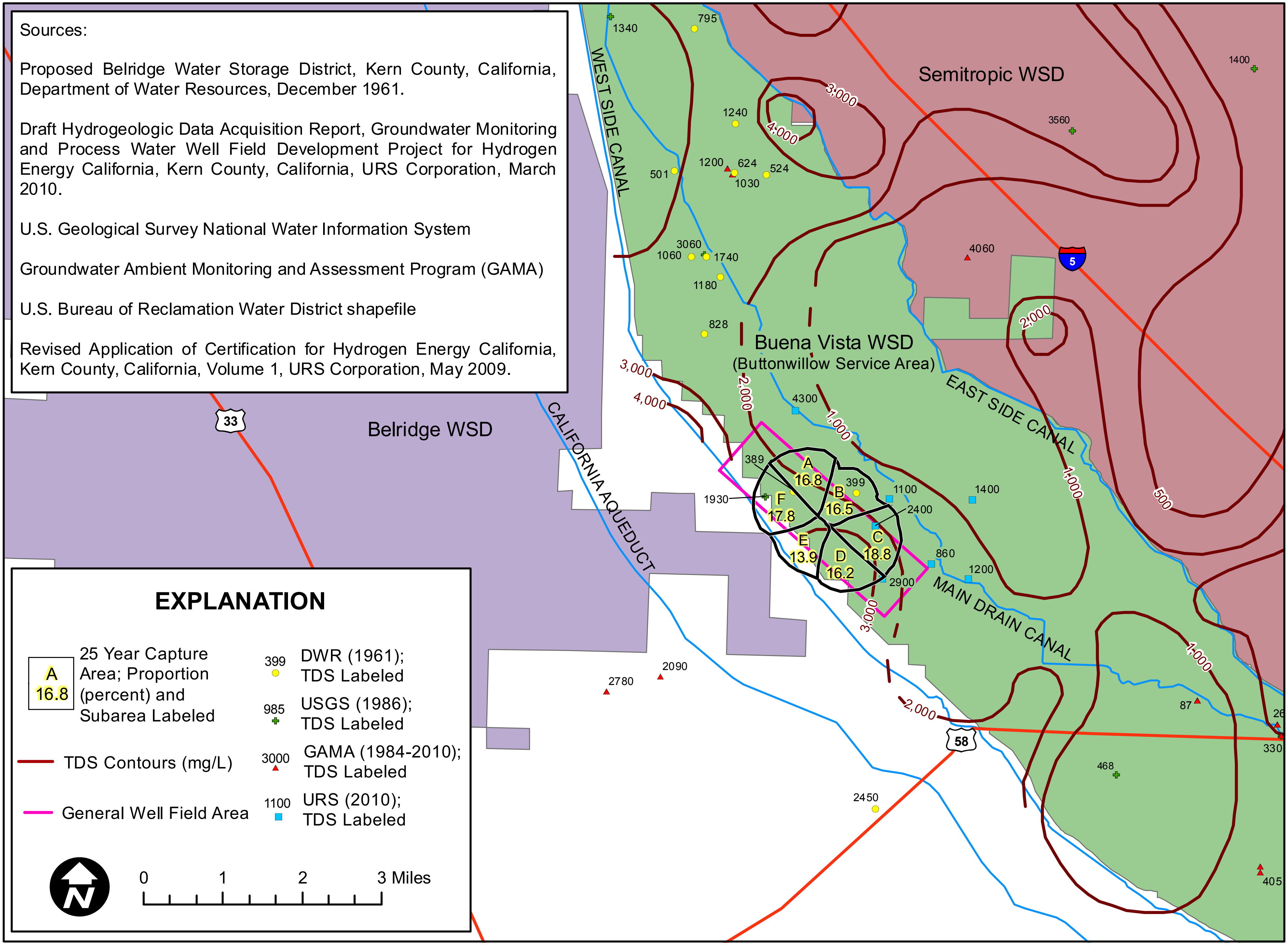
Water Figure16. Simulated 25-year Zone of Influence (ZOI) and volumetric budget for the applicant model and staff modified model including reduced storativity (0.007).



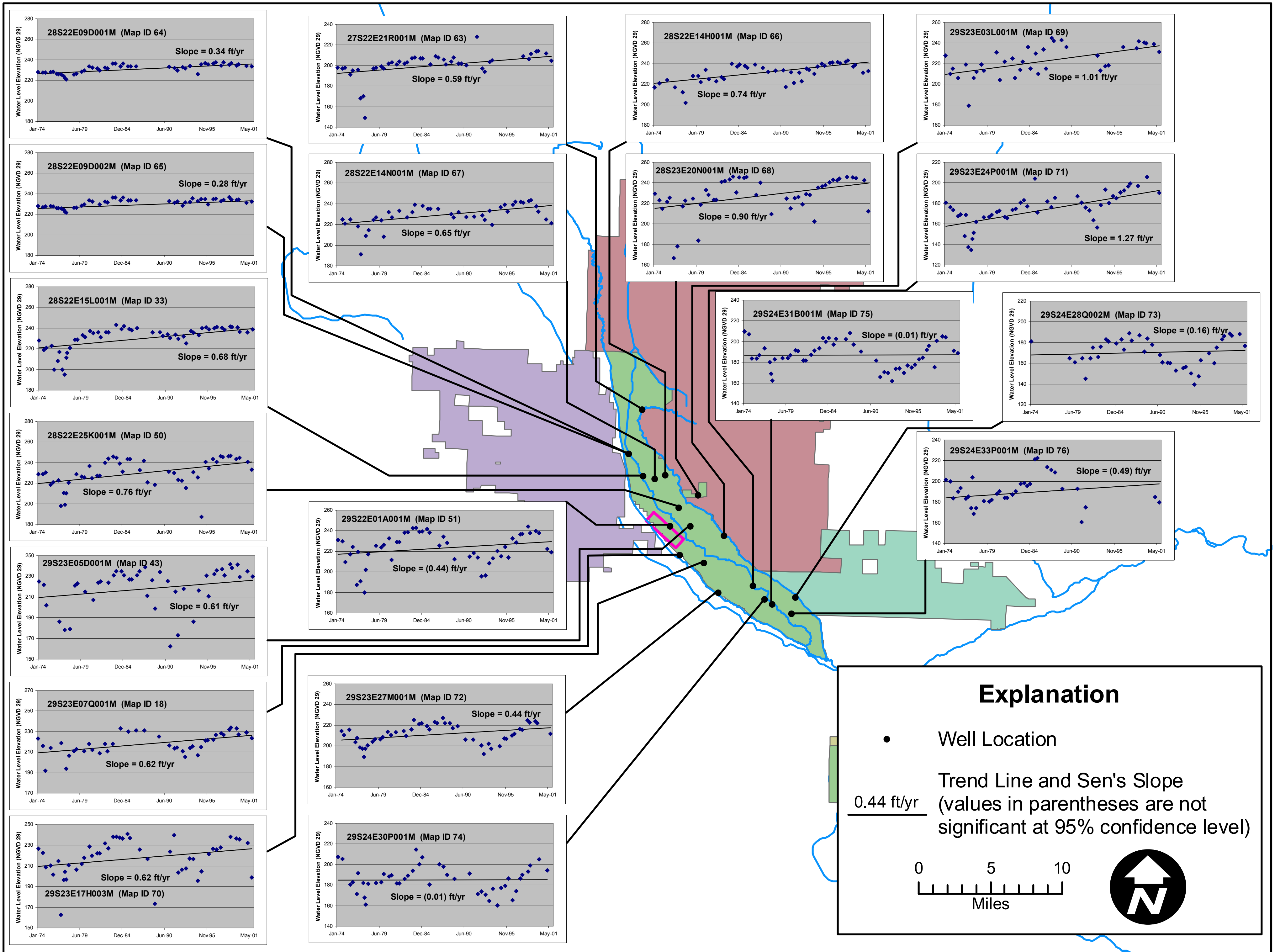
Volumetric Budget for the Well Field Zone of Influence (AF/yr)

	Applicant Model	High Anisotropy Model
Storage Change	61	10
Recharge	533	0
Extraction Wells	-7,500	-7,500
Inflow from West	907	2,333
Inflow from East	1,674	4,007
Inflow from beneath Well Screens	4,325	1,151
Note: Budget for Layer 1 only (water table to 300 feet below land surface).		
Up-coning (upward flow from beneath 600 feet depth)	0	5,454

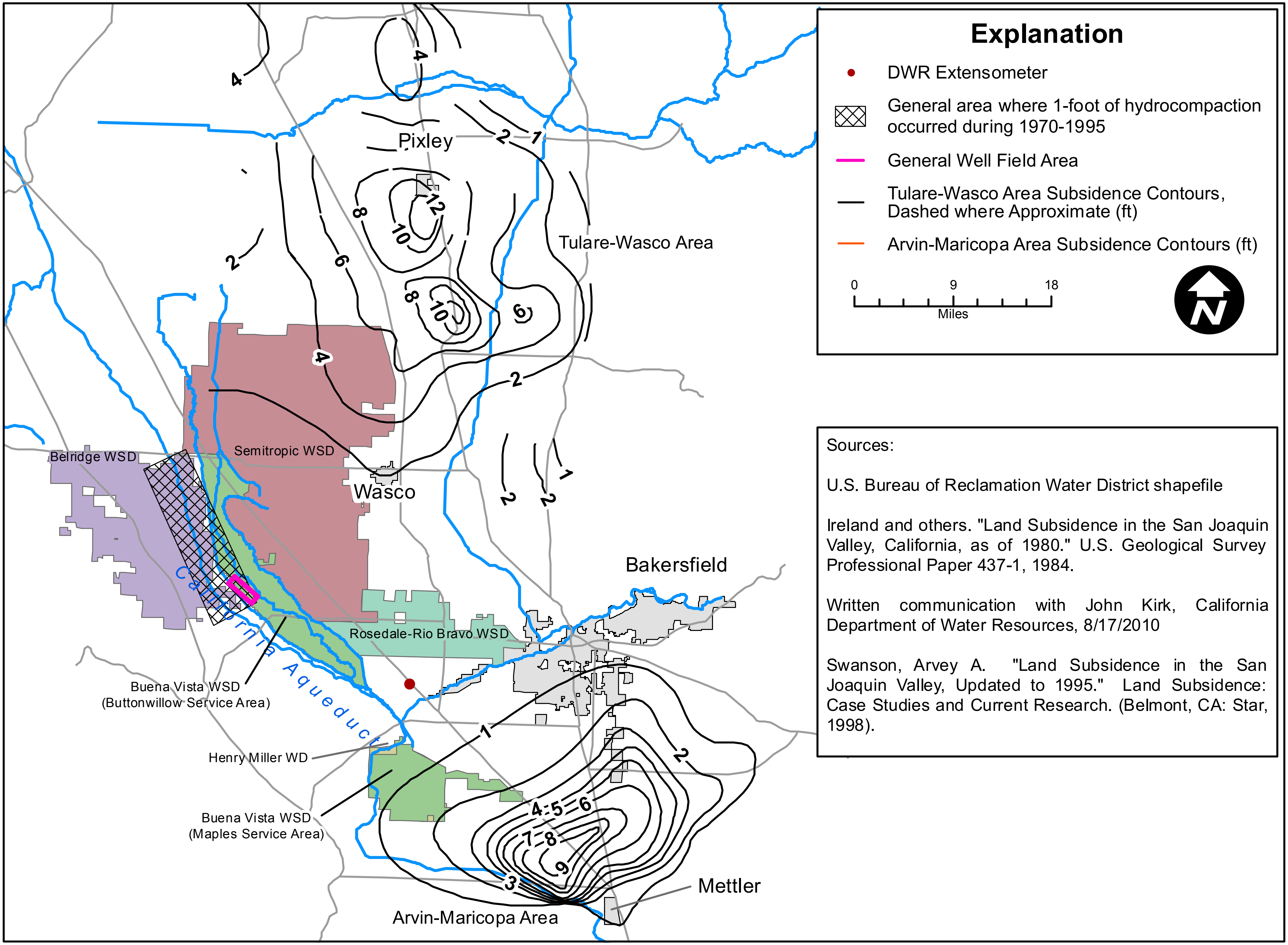
Water Figure 17. Simulated 25-year Zone of Influence (ZOI) and volumetric budget for the applicant model and staff-modified model and reduced storativity (0.007) with anisotropy increased to 1,000.



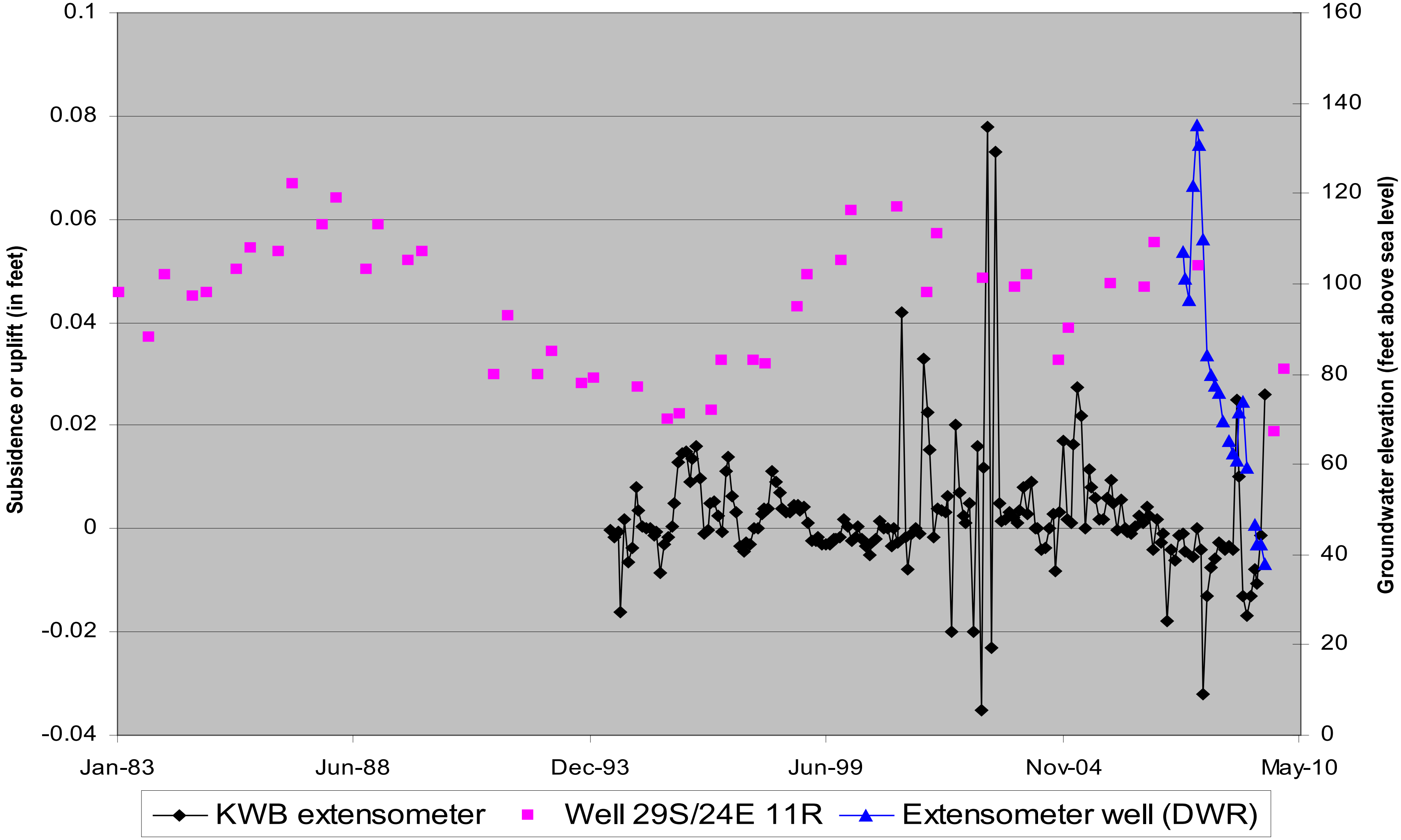
Water Figure 18. Composite 1970-2007 TDS concentration contours and 25-year Zone of Influence (ZOI) simulated by the applicant model.



Water Figure 19. Water level locations and trends in Buttonwillow Service Area, 1974-2001.



Water Figure 20. Historical subsidence and hydrocompaction areas and DWR extensometer location relative to BVWSD.



Sources:

Written communication with John Kirk, California Department of Water Resources (DWR), 8/17/2010.

California DWR Water Data Library

Soil and Water Figure 21. Water level changes in wells and observed aquifer compaction at the Kern Water Bank extensometer.

WORKER SAFETY AND FIRE PROTECTION

Alvin Greenberg, Ph.D.

SUMMARY OF CONCLUSIONS

Staff concludes that if the applicant for the proposed Hydrogen Energy California project (HECA) will provide project construction safety and health, project operations and maintenance safety and health plans and programs, and fire protection plans and programs as required by proposed Conditions of Certification **WORKER SAFETY-1,** through **-11**, the project would incorporate sufficient measures to both ensure adequate levels of industrial safety and fire protection and comply with applicable laws, ordinances, regulations, and standards (LORS). These proposed conditions of certification ensure that these programs would be reviewed by the appropriate agencies and approved by the Energy Commission compliance project manager before they are implemented. The conditions also require verification that the proposed plans adequately ensure worker safety and fire protection and comply with applicable LORS.

The proposed HECA project is a complex industrial facility similar in scope to a small refinery. The proposed project includes many chemical processes such as reactor vessels, storage vessels, treatment units, piping, valves, and flanges as well as transfer and transport facilities which would, if considered separately, each constitute a stand-alone industrial plant. The project proposes to use, store, create, and transport large volumes of several highly toxic hazardous materials. Furthermore, in addition to the actual facilities owned and operated by Hydrogen Energy California, this Preliminary Staff Assessment/Draft Environmental Impact Statement (PSA/DEIS) also includes an environmental review of the high-pressure CO_2 pipeline and enhanced oil recovery and carbon sequestration facility to be owned and operated by Occidental of Elk Hills, Inc.

The different processes and large volumes of hazardous materials that would be utilized at the proposed facility and described in this PSA/DEIS have the potential to pose significant threats to worker safety and also pose a serious threat of fire and/or explosion. These processes include the following:

1. A coal/petroleum coke gasification plant;
2. An air separation unit producing liquid oxygen and liquid nitrogen;
3. A syngas scrubber, sour shift, low-temperature gas cooling, sour water treatment facility;
4. A mercury removal unit;
5. An acid gas removal (Rectisol process) unit;
6. An ammonia synthesis unit that produces and includes anhydrous ammonia storage;
7. A urea unit;
8. A urea pastillation unit;
9. A urea pastille handling and transfer unit;
10. A urea ammonium nitrate complex that produces nitric acid, ammonium nitrate, and urea;

11. A sulfur recovery unit;

12. A 13-mile natural gas pipeline;

13. A 3-mile pressurized CO_2 pipeline;

14. An enhanced oil recovery (EOR) facility;

15. Additional storage of large volumes of hazardous materials including:

    a. sodium hydroxide

    b. sodium hypochlorite

    c. diesel fuel

    d. gasoline during construction

The presence of these complex chemical processes -- specifically the larger gasification process, sulfur recovery process, and anhydrous ammonia production and storage that would consist of large amounts of hazardous materials in closed tanks and piping at elevated temperature and pressure – could potentially pose significant risks to workers and have the potential to cause explosions and fires if not managed properly. Staff has not encountered such a complex power generation facility in the history of the Energy Commission and the Kern County Fire Department states it has not either. In order to properly review and assess the potential worker safety and fire protection issues, staff spent considerable time evaluating the entire process and even visited a similar gasification facility in Polk County, Florida. As a result of staff's efforts to understand the processes and the risks involved, staff determined that all of these processes must be managed and monitored in greater detail than usual and that a significant potential for accidents that would impact workers exists. Also, due to the complex nature of the project and numerous industrial processes that use highly combustible or flammable materials, coupled with the remote location in an area served by the Kern County Fire Department, staff found that a significant direct impact, as well as a cumulative impact, on the Kern County Fire department would exist but that these impacts can be mitigated with the adoption of proposed Conditions of Certification **WORKER SAFETY-8** and **-9**.

Also, as discussed in the **Introduction** section of the PSA, this document analyzes the project's impacts pursuant to both the National Environmental Policy Act (NEPA) and California Environmental Quality Act (CEQA). The two statutes are similar in their requirements concerning analysis of a project's impacts. Therefore, unless otherwise noted, staff's use of, and reference to, CEQA criteria and guidelines also encompasses and satisfies NEPA requirements for this environmental document.

INTRODUCTION

Worker safety and fire protection are regulated through federal, state, and local LORS. Industrial workers at the facility both operate equipment and handle hazardous materials daily, and could face hazards resulting in accidents and serious injury. Protection measures are employed to eliminate or reduce these hazards or minimize their risk through special training, protective equipment, and procedural controls.

The purpose of this Preliminary Staff Assessment/Draft Environmental Impact Statement (PSA/DEIS) is to assess the worker safety and fire protection measures proposed by the HECA applicant, determine whether the applicant has proposed adequate measures, and for staff to propose additional measures to:

- Comply with applicable safety LORS;
- Protect workers during the construction and operation of the facility;
- Protect against fire; and
- Provide adequate emergency response procedures.

The original AFC (08-AFC-8) was filed with the Energy Commission on July 31, 2008; and a Revised AFC was submitted in 2009 to reflect a change of the project site to an alternative location. In 2011, Hydrogen Energy California, LLC, (HECA) was acquired from the previous owners by SCS Energy California, LLC. On May 2, 2012, SCS Energy, LLC, submitted an Amended Application for Certification (08-AFC-8A) reflecting several changes to the original project design.

The new Amended Application for Certification (AFC) has been assigned a separate distinguishing docket number, 08-AFC-8A. The Amended AFC for the project supersedes and replaces all previous submissions, and incorporates all relevant information from the previous versions of the HECA proceedings. The applicant intends to construct and operate an integrated gasification combined cycle (IGCC) power generating facility called Hydrogen Energy California (HECA).

The proposed HECA project would gasify a mixture of western coal and petroleum coke from California refineries to produce hydrogen to fuel a combustion turbine operating in combined-cycle mode. The amended project incorporates a proposed manufacturing complex that would produce urea in both liquid and pellet form, and other byproducts for agricultural uses.

For power generation, a Mitsubishi Heavy Industries MHI 501GAC® CT combustion turbine has been selected. The combined cycle power block would generate approximately 405 MW of gross power and would provide about 300-megawatts of electricity to the grid. The gasification block would also capture carbon from the raw syngas (the direct end of the gasification process) at steady-state operation, which would be transported to a custody transfer point at the Elk Hills Oil Field for CO_2 enhanced oil recovery (EOR) and sequestration. Due to the complex gasification and sequestration process, there is a larger than usual parasitic electrical load.

Highlights of the project include:

- The Amended HECA facility proposes to operate with 25 percent petroleum coke from California refineries blended with 75 percent western bituminous coal. Transportation of coal to the project would be by either a truck route, or via an alternative rail spur proposed to be built and owned by the applicant.
- The feedstock (coal and petroleum coke) would be gasified to produce a synthesis gas (syngas) that would be processed and purified to produce a hydrogen-rich gas, which would be used to fuel the combustion turbine for electric power generation and provide supplemental fuel to the heat recovery steam generator (HRSG) that

produces steam from the combustion turbine exhaust heat. At least 90 percent of the carbon in the raw syngas would be captured in a high-purity carbon dioxide stream during steady-state operation, and would be sold to Occidental Petroleum, compressed and transported by pipeline off-site to the nearby Elk Hills Oil Field for injection into deep underground oil reservoirs for enhanced oil recovery (EOR) and sequestration.

- State-of-the-art emission controls are included in the design.
- Zero Liquid Discharge technology is used in the project design for process and waste water.
- Liquid oxygen and nitrogen are produced in the air separation unit, and supplied to the gasification unit, the combustion turbine, sulfur recovery unit and other process components of HECA.

Some notable project changes are proposed in the Amended AFC, including the following:

- Mitsubishi Heavy Industries (MHI) oxygen-blown dry feed gasification technology has been selected.
- A MHI 501GAC® Combustion Turbine and Steam Turbine has been selected.
- A new, integrated manufacturing complex (IMC) will produce approximately 1 million tons per year of low-carbon nitrogen-based products, including urea ammonium nitrate and anhydrous ammonia, to be used in agriculture.

HECA proposes to use two alternatives for transporting coal to the project site:

Alternative 1, Rail Transportation: An approximately 5-mile new industrial railroad spur would connect the project site to the existing San Joaquin Valley Railroad, Buttonwillow railroad line, north of the project site. This railroad spur would also be used to transport some IMC products to customers.

Alternative 2, Truck Transportation: Truck transport would be via existing roads from an existing coal transloading facility northeast of the project site. The truck route distance is approximately 27 miles.

The routes of the natural gas pipeline, potable water pipeline, and electrical transmission have been refined as follows:

- An approximately 13-mile new natural gas pipeline will interconnect with an existing Pacific Gas and Electric Company (PG&E) natural gas pipeline located north of the project site.
- Potable water will be delivered via an approximately 1-mile pipeline from a new West Kern Water District potable water production site east of the project site.
- An approximately 2-mile electrical transmission line will interconnect with a future PG&E switching station east of the project site.

If approved, construction of the project is proposed by the applicant to begin 2013 or 2014, with completion of construction in 2017, and commencement of commercial operation by the end of 2017. However, it is highly likely that the construction would start, if approved by the commission, sometime in 2014 and commencement of commercial operations occur sometime in 2018 or 2019.

Worker Safety and Fire Protection Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	
29 U.S. Code sections 651 et seq (Occupational Safety and Health Act of 1970)	This Act mandates safety requirements in the workplace, with the purpose of "[assuring] so far as possible every working man and woman in the nation safe and healthful working conditions and to preserve our human resources" (29 USC § 651).
29 CFR sections 1910.1 to 1910.1500 (Occupational Safety and Health Administration Safety and Health Regulations)	These sections define the procedures for promulgating regulations and conducting inspections to implement and enforce safety and health procedures to protect workers, particularly in the industrial sector.
29 CFR sections 1952.170 to 1952.175	These sections provide federal approval of California's plan for enforcement of its own safety and health requirements, in lieu of most of the federal requirements found in 29 CFR §1910.1 to 1910.1500.
State	
8 CCR all applicable sections (Cal/OSHA regulations)	Requires that all employers follow these regulations as they pertain to the work involved. This includes regulations pertaining to safety matters during the construction, commissioning, and operation of power plants, as well as safety around electrical components, fire safety, and hazardous materials usage, storage, and handling.
24 CCR section 3, et seq.	Incorporates the current edition of the International Building Code.
Health and Safety Code sections 25500 to 25541	Requires a Hazardous Materials Business plan detailing emergency response plans for hazardous materials emergencies at a facility.
Local (or locally enforced)	
2010 Edition of California Fire Code (24 CCR Part 9)	The fire code contains general provisions for fire safety, including road and building access, water supplies, fire protection and life safety systems, fire-resistive construction, storage of combustible materials, exits and emergency escapes, and fire alarm systems. It is based on the 2009 edition of the International Fire Code.
Title 24, California Code of Regulations (24 CCR § 3, et seq.)	The California Building Code comprises 11 parts containing building design and construction requirements as they relate to fire, life, and structural safety. It incorporates current editions of the International Building Code, including the electrical, mechanical, energy, and fire codes applicable to the project.

NFPA Standards And Standard 850	NFPA is a professional organization that adopts fire protection standards and guidelines for industry, government, and fire departments. NFPA 850 addresses fire protection at power plants.
Kern County Fire Code Chapter 17.32 of the Code of Building Regulations	Kern County adopted and enforces the 2006 edition of the International Fire Code.
Kern County Zoning Ordinance, Development Standards section 19.80.030.	Contains safety setbacks required by the Kern County Fire Department.

SETTING

Fire support services to the site will be under the jurisdiction of the Kern County Fire Department (KCFD). KCFD fire Station 25 is 7 miles from the project site, located at 100 Mirasol Avenue, Buttonwillow, California, and would be the first responder to an emergency at the HECA facility with a three-person crew and one type-2 fire engine and one 4WD fire patrol vehicle. The response time from first notification would be no more than 15 minutes. The next station that would respond is located in McKittrick (station 24) and it has the same staffing and equipment. The response time to the HECA site from first notification would be ~25-30 minutes. The third in line for response to the HECA site would be station 53 located on Highway 53 east of I-5. This station is proposed for re-location west of I-5 with an addition of a helipad. The fourth station that would respond is station 21 located in Taft and this includes a ladder company. All four stations are continuously staffed with three personnel per shift.

In Kern County, hazardous materials permits and spills are handled and investigated by the KCFD. Kern County firefighters receive specialized training to address emergency responses to industrial hazards, and response would come from the same facilities as for fire services response. If ever needed, a specialized hazardous materials response team would come from 3000 Landco Drive, Bakersfield, CA with a response time of approximately 50 minutes.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

Two issues are assessed in **Worker Safety and Fire Protection**:

1. The potential for impacts on the safety of workers during demolition, construction, and operation activities; and

2. Fire prevention/protection, emergency medical response, and hazardous materials spill response during construction and operations.

Staff's worker safety analysis is essentially a LORS conformity review and if all LORS are followed, workers will be adequately protected. Thus, the standard for staff's review and determination is whether the applicant has demonstrated adequate knowledge of, and commitment to, implementation of all pertinent and relevant Cal-OSHA standards.

Staff reviews and evaluates the on-site fire-fighting systems proposed by the applicant, as well as the time needed for off-site local fire departments to respond to a fire, medical, or hazardous material emergency at the HECA site. If on-site systems do not follow established codes and industry standards, staff recommends additional measures. Staff reviews local fire department capabilities and response times, and interviews local fire officials to determine if they feel they are adequately staffed, and equipped to respond to the needs of a power plant. Staff then determines if the presence of the power plant would cause a significant impact on a local fire department. If it does, staff will recommend that the applicant mitigate this impact by providing additional resources to the fire department.

DIRECT/INDIRECT IMPACTS AND MITIGATION

Worker Safety

Industrial environments are potentially dangerous during both construction and operation. Workers at the proposed project will be exposed to loud noises, moving equipment, trenches, and confined space entry and egress. Workers may sustain falls, trips, burns, lacerations, and other injuries. They may be exposed to falling equipment or structures, chemical spills, hazardous waste, fires, explosions, and electrical sparks or electrocution. It is important that HECA has well-defined policies and procedures, training, and hazard recognition and control to minimize these hazards and protect workers. If the facility complies with all LORS, workers will be adequately protected from health and safety hazards.

A Safety and Health Program will be prepared by the applicant to minimize worker hazards during construction and operation of the project. "Safety and Health Program," for staff, refers to measures that will be taken to ensure compliance with the applicable LORS during the construction and operation of the project.

Construction Safety and Health Program

The project includes the construction and operation of a power plant that includes a petroleum coke (pet coke) and coal gasification unit with all its associated hazardous chemical separation and fuel handling systems along with several industrial operations that make urea ammonia nitrate fertilizer (UAN) and liquid sulfur for shipment off-site for distribution and commercial sale. Although workers would be exposed to hazards typical of construction of an industrial facility and gas-fired power plant, workers would be exposed to hazards during operations that could be described as anything but typical.

Construction safety orders are published at Title 8 of the California Code of Regulations, section 1502 et seq. These requirements are promulgated by Cal/OSHA and apply to the construction phase of the project. The construction safety and health program will include the following:

- Construction injury and illness prevention program (8 CCR § 1509);

- Construction fire prevention plan (8 CCR § 1920);
- Personal protective equipment program (8 CCR §§ 1514 - 1522); and
- Emergency action program and plan.

Additional programs under General Industry Safety Orders (8 CCR §§ 3200 to 6184), Electrical Safety Orders (8 CCR §§2299 to 2974) and Unfired Pressure Vessel Safety Orders (8 CCR §§ 450 to 544) will include:

- Electrical safety program;
- Motor vehicle and heavy equipment safety program;
- Forklift operation program;
- Excavation/trenching program;
- Fall protection program;
- Scaffolding/ladder safety program;
- Articulating boom platforms program;
- Crane and material handling program;
- Housekeeping and material handling and storage program;
- Respiratory protection program;
- Employee exposure monitoring program;
- Hand and portable power tool safety program;
- Hearing conservation program;
- Back injury prevention program;
- Hazard communication program;
- Heat and cold stress monitoring and control program;
- Pressure vessel and pipeline safety program;
- Hazardous waste program;
- Hot work safety program;
- Permit-required confined space entry program; and
- Demolition procedure (if applicable).

The AFC includes adequate outlines for each of the above programs (HECA 2012e, section 5.7.2.1). The applicant also provided information on the proposed Construction/Commissioning Fire Protection Plan (HECA 2012e, sections 5.7.2.1 and 2.9.12). Prior to the project's start of construction, detailed programs and plans will be provided pursuant to Condition of Certification **WORKER SAFETY-1**.

Operations and Maintenance Safety and Health Program

Prior to the start-up of HECA, an operations and maintenance safety and health program will be prepared. This program will include the following programs and plans:

- Injury and illness prevention program (8 CCR § 3203);
- Fire prevention program (8 CCR § 3221);
- Personal protective equipment program (8 CCR §§ 3401 to 3411); and
- Emergency action plan (8 CCR § 3220).

In addition, the requirements under General Industry Safety Orders (8 CCR §§ 3200 to 6184), Electrical Safety Orders (8 CCR §§2299 to 2974) and Unfired Pressure Vessel Safety Orders (8 CCR §§ 450 to 544) will apply to this project. Written safety programs for HECA, which the applicant will develop, will ensure compliance with those requirements.

The AFC includes adequate outlines for an operations injury and illness prevention program, an emergency action plan, a fire prevention program, and a personal protective equipment program (HECA 2012e, section 5.7.2.3). Prior to operation of HECA, all detailed programs and plans will be provided pursuant to Condition of Certification **WORKER SAFETY-2**.

Safety and Health Program Elements

As mentioned above, the applicant provided the proposed outlines for both a Construction Safety and Health Program and an Operations Safety and Health Program. The measures in these plans are derived from applicable sections of state and federal law. The major items required in both safety and health programs are as follows:

Injury and Illness Prevention Program (IIPP)

The IIPP will include the following components (HECA 2012e, section 5.7.2.3):

- Identify persons with the authority and responsibility for implementing the program;
- Establish the safety and health policy of the plan;
- Define work rules and safe work practices for work activities;
- Establish a system for ensuring that employees comply with safe and healthy work practices;
- Establish a system to facilitate employer-employee communication;
- Develop procedures for identifying and evaluating workplace hazards and establish necessary program(s);
- Establish methods for correcting unhealthy/unsafe conditions in a timely manner;
- Determine and establish training and instruction requirements and programs;
- Specify safety procedures; and
- Provide training and instruction.

Fire Prevention Plan

The California Code of Regulations requires an operations fire prevention plan (8 CCR § 3221). The AFC outlines a proposed fire prevention plan that is acceptable to staff (HECA 2012e, section 5.7.2.10). The plan will include the following:

- Determine general program requirements;
- Determine fire hazard inventory, including ignition sources and mitigation;
- Develop good housekeeping practices and proper materials storage;
- Establish employee alarms and/or communication system(s);
- Provide portable fire extinguishers at appropriate site locations;
- Locate fixed firefighting equipment in suitable areas;
- Specify fire control requirements and procedures;
- Establish proper flammable and combustible liquid storage facilities;
- Identify the location and use of flammable and combustible liquids;
- Provide proper dispensing and determine disposal requirements for flammable liquids;
- Establish and determine training and instruction requirements and programs; and
- Identify contacts for information on plan contents.

Staff proposes that the applicant submit a final fire prevention plan to the California Energy Commission compliance project manager (CPM) for review and approval and to the KCFD for review and comment to satisfy proposed conditions of certification **WORKER SAFETY-1** and **WORKER SAFETY-2**.

Personal Protective Equipment Program

California regulations require personal protective equipment (PPE) and first aid supplies whenever hazards in the environment, or from chemicals or mechanical irritants, could cause injury or impair bodily function through absorption, inhalation, or physical contact (8 CCR sections 3380 to 3400). The HECA operational environment will require PPE (HECA 2012e, section 5.7.2.6).

All safety equipment must meet National Institute of Safety and Health (NIOSH) or American National Standards Institute (ANSI) standards and will carry markings, numbers, or certificates of approval. Respirators must meet NIOSH and Cal/OSHA standards. Each employee must be provided with the following information about protective clothing and equipment:

- Proper use, maintenance, and storage;
- When protective clothing and equipment are used;
- Benefits and limitations; and
- When and how protective clothing and equipment are replaced.

The PPE program ensures that employers comply with applicable requirements for PPE and provides employees with the information and training necessary to protect them from potential hazards in the workplace, and will be required as per proposed Conditions of Certification **WORKER SAFETY-1** and **-2**.

Emergency Action Plan

California regulations require an emergency action plan (8 CCR § 3220). The AFC contains a satisfactory outline for an emergency action plan (HECA 2012e, section 5.7.2.2 and Tables 5.7-5).

The outline describes the following features:

- Establishes emergency procedures for the protection of personnel, equipment, the environment, and materials;
- Identifies fire and emergency reporting procedures;
- Determines response actions for accidents involving personnel and/or property;
- Develops response and reporting requirements for bomb threats;
- Specifies site assembly and emergency evacuation route procedures;
- Defines natural disaster responses (for example, earthquakes, high winds, and flooding);
- Establishes reporting and notification procedures for emergencies (including on-site, off-site, local authorities, and/or state jurisdictions);
- Determines alarm and communication systems needed for specific operations;
- Includes a spill response, prevention, and countermeasure (SPCC) plan;
- Identifies emergency personnel (response team) responsibilities and notification roster;
- Specifies emergency response equipment and strategic locations; and
- Establishes and determines training and instruction requirements and programs.

An emergency action plan will be required as per proposed Conditions of Certification **WORKER SAFETY-1 and -2**

Written Safety Program

In addition to the specific plans listed above, additional LORS called “safe work practices” apply to the project. Both the construction and operations safety programs will address safe work practices in a variety of programs. The components of these programs include, but are not limited to, the programs found under the heading “Construction Safety and Health Program” in this staff assessment.

In addition, the project owner would be required to provide personnel protective equipment and exposure monitoring for workers involved in activities where contaminated soil and/or contaminated groundwater exist, per staff’s proposed Conditions of Certification **WORKER SAFETY-1** and**-2**.

These proposed conditions of certification ensure that workers are properly protected from any hazardous wastes presently at the site.

Safety Training Programs

Employees will be trained in the safe work practices described in the above-referenced safety programs.

Additional Mitigation Measures

Protecting construction workers from injury and disease is one of the greatest challenges today in occupational safety and health. The following facts are reported by NIOSH:

- More than seven million persons work in the construction industry, representing six percent of the labor force. Approximately 1.5 million of these workers are self-employed;
- Of approximately 600,000 construction companies, 90 percent employ fewer than 20 workers. Few have formal safety and health programs;
- From 1980-1993, an average of 1,079 construction workers were killed on the job each year, with more fatal injuries than any other industry;
- Falls caused 3,859 construction worker fatalities, or 25.6 percent of the total, between 1980 and 1993;
- 15 percent of workers' compensation costs are spent on construction-related injuries;
- Ensuring safety and health in construction is a complex task involving short-term work sites, changing hazards, and multiple operations and crews working in close proximity to one another;
- In 1990, Congress directed NIOSH to conduct research and training to reduce diseases and injury among construction workers in the United States. Under this mandate, NIOSH funds both intramural and extramural research projects.

The hazards associated with the construction industry are well documented. These hazards increase in complexity in the multi-employer worksites typical of large, complex industrial projects such as the proposed HECA project. In order to reduce and/or eliminate these hazards, it has become standard industry practice to hire a construction safety supervisor to ensure a safe and healthful environment for all workers. This has been evident in the audits of power plants recently conducted by the staff. The Federal Occupational Safety and Health Administration (OSHA) has also entered into strategic alliances with several professional and trade organizations to promote and recognize safety professionals trained as construction safety supervisors, construction health and safety officers, and other professional designations. The goal of these partnerships is to encourage construction subcontractors to improve their safety and health performance; to assist them in striving to eliminate the four major construction hazards (falls, electrical, caught in/between, and struck-by hazards) that account for the majority of fatalities and injuries in this industry and have been the focus of targeted OSHA inspections; to prevent serious accidents in the construction industry through implementation of enhanced safety and health programs and increased employee training; and to recognize subcontractors that have exemplary safety and health programs.

There are no OSHA or Cal-OSHA requirements that an employer hire or provide for a construction safety officer. OSHA and Cal-OSHA regulations do, however, require that safety be provided by an employer and the term “Competent Person” appears in many OSHA and Cal-OSHA standards, documents, and directives. A “Competent Person” is defined by OSHA as an individual who, by way of training and/or experience, is knowledgeable of standards, is capable of identifying workplace hazards relating to the specific operations, is designated by the employer, and has authority to take appropriate action. Therefore, in order to meet the intent of the OSHA standard to provide for a safe workplace during power plant construction, staff proposes Condition of Certification **WORKER SAFETY-3,** which would require the project owner to designate and provide for a project site construction safety supervisor.

As discussed above, the hazards associated with the construction industry are well documented. These hazards increase in complexity in the multi-employer worksites typical of large, complex industrial projects like a coal gasification power plant, a UAN production plant, a sulfur plant, and with the storage of large amounts of hazardous materials such as anhydrous ammonia, methanol, cryogenic liquids, and nitric acid.

When project owners have failed to recognize and control safety hazards and there is inadequate monitoring of compliance with occupational safety and health regulations, accidents, fires, and a worker death have occurred. Safety problems have been documented by Energy Commission staff in safety audits conducted since 2005 at several power plants under construction. The findings of the audits include, but are not limited to, safety oversights like:

- Lack of posted confined-space warning placards/signs;
- Confusing and/or inadequate electrical and machinery lockout/tagout permitting and procedures;
- Confusing and/or inappropriate procedures for handing over lockout/tagout and confined space permits from the construction team to the commissioning team, and then to operations;
- Dangerous placement of hydraulic elevated platforms under one another;
- Inappropriate placement of fire extinguishers near hot work;
- Dangerous placement of numerous power cords in standing water on the site, increasing the risk of electrocution;
- Inappropriate and unsecured placement of above-ground natural gas pipelines inside the facility, but too close to the perimeter fence; and
- Lack of adequate employee or contractor written training programs that address the proper procedures to follow in the event of the discovery of suspicious packages or objects either onsite or offsite.

In order to reduce and/or eliminate these hazards, it is necessary for the Energy Commission to require a professional Safety Monitor on-site to track compliance with

Cal-OSHA regulations and periodically audit safety compliance during construction, commissioning, and the hand-over to the operations staff. These requirements are outlined in Condition of Certification **WORKER SAFETY-4**. A Safety Monitor, hired by the project owner but reporting to the chief building official (CBO) and the compliance project manager (CPM), will serve as an extra set of eyes to ensure that safety procedures and practices are fully implemented during construction at all power plants certified by the Energy Commission. During audits conducted by staff, most site safety professionals welcomed the audit team and actively engaged them in questions about the team's findings and recommendations. These safety professionals recognized that safety requires continuous vigilance and that the presence of an independent audit team provides a "fresh perspective" of the site.

In addition, because of the complexity of this project, staff recommends an additional safety measure found in proposed condition **WORKER SAFETY-10** that would require the project owner to ensure that during commissioning and operations, at least one person would be on the site at all times (24 hours/day, 7 days/week) who was knowledgeable of and dedicated to safety, security, and fire protection.

Valley Fever (Coccidioidomycosis)

Coccidioidomycosis or "Valley Fever" (VF) is primarily encountered in southwestern states, particularly in Arizona and California. It is caused by inhaling the spores of the fungus Coccidioides immitis (*c.immitis)*, which are released from the soil during soil disturbance (e.g., during construction activities) or wind erosion. The disease usually affects the lungs and can have potentially severe consequences, especially in at-risk individuals such as the elderly, pregnant women, and people with compromised immune systems.

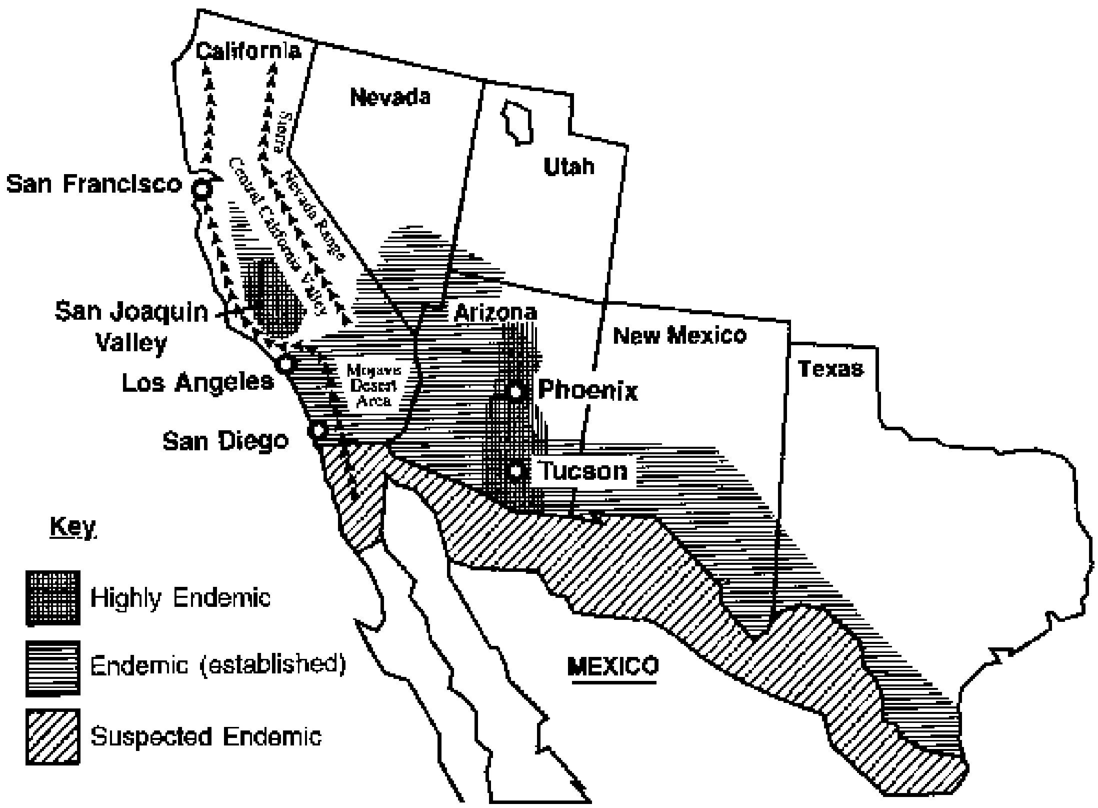
A February 2013 outbreak of Valley Fever affecting at least 28 workers at a photovoltaic solar plant in eastern San Luis Obispo County, along with an increase in inmates at two San Joaquin Valley prisons coming down with the disease, has sparked renewed interest and concern. (The California Department of Public Health, Cal-OSHA, and San Luis Obispo County are investigating that outbreak.) The Centers for Disease Control and Prevention says the total number of Valley Fever cases nationwide rose by nearly 900 percent from 1998 to 2011. Researchers don't have a good explanation for the dramatic increase even when accounting for growing populations throughout the Southwest, although when soil is dry and it is windy, more spores are likely to become airborne in endemic areas, according to Dr. Gil Chavez, Deputy Director of the Center for Infectious Diseases at the California Department of Public Health.

Trenching, excavation, and construction workers are often the most exposed population. Treatment usually includes rest and antifungal medications. No effective vaccine currently exists for Valley Fever. VF is endemic to the San Joaquin Valley in California, which presumably gave this disease its common name. Kern County, located at the southern end of the San Joaquin Valley, is where Valley Fever occurs most frequently (Valley Fever Vaccine Project of the Americas 2010; KCDPH 2008). Depending on the particular year, either Tulare or Fresno county have the second highest rates of VF.

In 1991, 1,200 cases of VF were reported to the California Department of Health Services (CDHS) compared with an annual average of 428 cases per year for the period of 1981 to 1990. In 1992, 4,516 cases were reported in California and 4,137 cases in 1993. Seventy percent of VF cases were reported from Kern County (CDC 1994; Flaherman 2007; CDHS 2010).

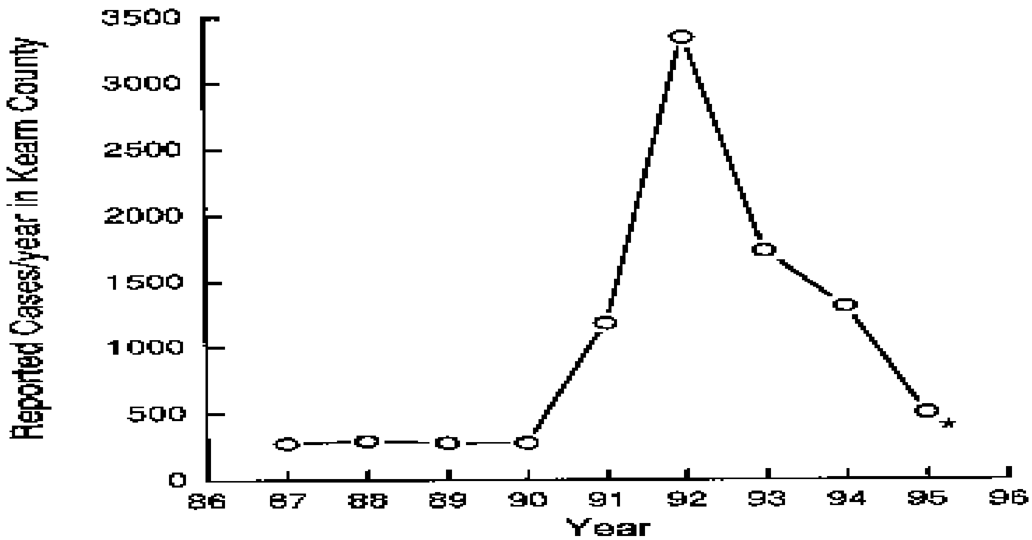
A 2004 CDC report found that the number of reported cases of coccidioidomycosis in the U.S. increased by 32 percent during 2003-2004, with the majority of these cases occurring in California and Arizona. The report attributed these increases to changes in land use, demographics, and climate in endemic areas, although certain cases might be attributable to increased physician awareness and testing (CDC 2006).

Worker Safety Figure 1
The Geographic Distribution of Coccidioidomycosis*



*Source: CDC 2006, Figure 2

Worker Safety Figure 2
Number of Coccidioidomycosis Cases Identified by Serologic Testing at the Kern County Public Health Laboratory between 1986 and 1996*



*Source: CDC 2006, Figure 4

According to the CDC Morbidity and Mortality Weekly Report of February 2009, incidences of valley fever have increased steadily in Arizona and California in the past decade. Cases of coccidioidomycosis averaged about 2.5 per 100,000 population annually from 1995 to 2000 and increased to 8.0 per 100,000 population between 2000 and 2006 (incident rates tripled). In 2007 there was a slight drop in cases, but the rate was still the highest it has been since 1995. The report identified Kern County as having the highest incidence rates (150.0 cases per 100,000 population), and non-Hispanic blacks having the highest hospitalization rates (7.5 per 100,000 population). In addition, between the years 2000 and 2006, the number of valley fever related hospitalizations climbed from 1.8 to 4.3 per 100,000 population (611 cases in 2000 to 1,587 cases in 2006) and then decreased to 1,368 cases in 2007 (3.6 per 100,000 population). Overall in California, during 2000-2007, a total of 752 (8.7 percent) of the 8,657 persons hospitalized for coccidioidomycosis died (CDC 2009).

A 2007 study published in the Emerging Infectious Diseases journal of the Center for Disease Control and Prevention (CDC), found the frequency of hospitalization for coccidioidomycosis in the entire state of California to be 3.7 per 100,000 residents per year for the period between 1997 and 2002 (see Table 1 below). There were 417 deaths from VF in California in those years, resulting in a mortality rate of 2.1 per 1 million California residents annually. The data shows that Kern County had the highest total number and highest frequency of hospitalizations (Flaherman 2007).

Worker Safety Table 1
Hospitalizations for Coccidioidomycosis, California, 1997 – 2002*

Category	Total hospitalizations	Total person-years (× 10^6)	Frequency of hospitalization**	Frequency of hospitalization for coccidioidal meningitis**
Total	7,457	203.0	3.67	0.657
Year				
1997	1,269	32.5	3.90	0.706
1998	1,144	32.9	3.50	0.706
1999	1,167	33.4	3.5	0.61
2000	1,100	34.0	3.23	0.62
2001	1,291	34.7	3.7	0.58
2002	1,486	35.3	4.2	0.71
Highest incidence counties				
Kern	1,700	3.97	42.8	
Tulare	479	2.21	21.7	
Kings	133	0.77	17.4	
San Luis Obispo	170	1.48	11.5	

*Source: Flaherman 2007
**Per 100,000 residents per year

A 1996 paper that tried to explain the sudden increase in Coccidioidomycosis cases that began in the early 90s found that the San Joaquin Valley in California has the largest population of C. immitis, which is found to be distributed unevenly in the soil and seems to be concentrated around animal burrows and ancient Indian burial sites. It is usually found 4 to 12 inches below the surface of the soil (CDC 2006). The paper also reported that incidences of coccidioidomycosis vary with the seasons; with highest rates in late summer and early fall when the soil is dry and the crops are harvested. Dust storms are frequently followed by outbreaks of coccidioidomycosis (CDC 2006). A modeling attempt to establish the relationship between fluctuations in VF incident rates and weather conditions in Kern County found that there is only a weak connection between weather and VF cases (weather patterns correlate with up to 4% of outbreaks). The study concluded that the factors that cause fluctuations in VF cases are not weather-related but rather biological and anthropogenic (i.e. human activities, primarily construction on previously undisturbed soil) (Talamantes 2007).

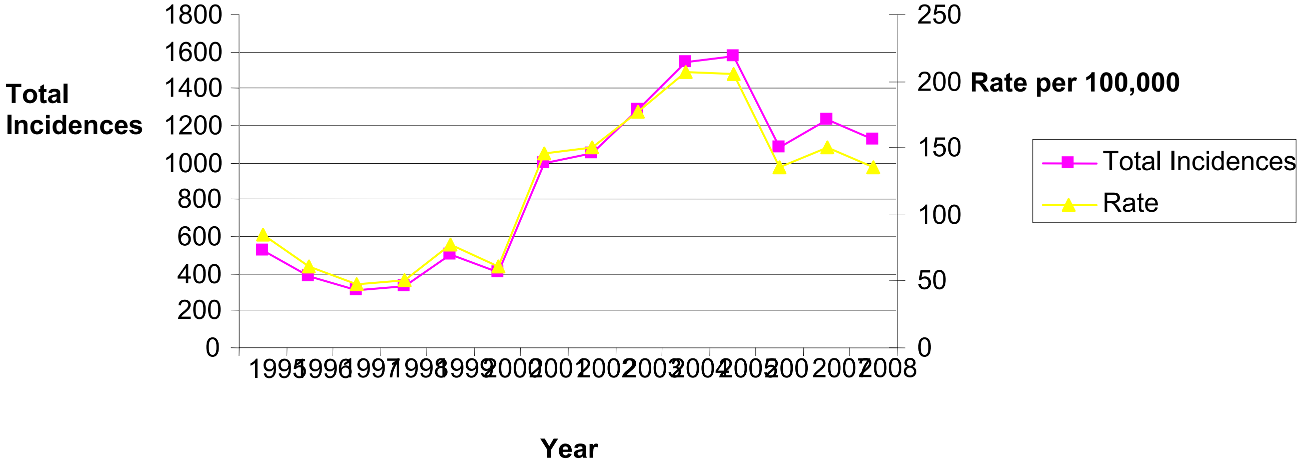
Data from the Kern County Department of Public Health (KCDPH) on the period between 1995 and 2008 shows that VF cases increased in Kern County during the early 1990’s, decreased during the late 1990’s, increased again between 2000 and 2005, and have been declining slightly in the last several years. The majority of VF cases are recorded in the Bakersfield area where 50 to 70 percent of all Kern County VF cases occur. Delano, Lamont, and Taft have the next highest recorded incidences of VF.

Worker Safety Table 2
Valley Fever Cases In Kern County 1995 – 2008*

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Kern County Cases	523	382	307	328	504	406	994	1055	1281	1540	1578	1081	1229	1128
Rate per 100,000	84.5	61	48.3	51.2	77.1	61	145.7	150.9	177.7	206.9	204.9	135.2	150.4	135.1

*Source: KCDPH 2008, Table 1

Worker Safety Figure 3
VF Cases in Kern County 1995 - 2008*



*Source: KCDPH 2008, Figure 2

During a phone conversation with Dr. Michael MacLean of the Kings County Health Department, he noted that according to his experience and of those who study VF, it is very hard to find the fungus in soil that was previously farmed and irrigated, which greatly reduces the risk of infection resulting from disturbance of farmed lands (MacLean 2009). This does not apply to previously undisturbed lands where excavation, grading, and construction may correlate with increases in VF cases. Dr. MacLean feels that with the current state of knowledge, we can only speculate on the causes and trends influencing VF cases and he does not feel that construction activities are necessarily the cause of VF outbreaks (KCEHS 2009).

Valley Fever is spread through the air. If soil containing the fungus is disturbed by construction, natural disasters, or wind, the fungal spores get into the air where people can breathe in the spores. The disease is not spread from person to person. Occupational or recreational exposure to dust is an important consideration. Agricultural workers, construction workers, or others (such as archeologists) who dig in the soil in the disease-endemic area of the Central Valley are at the highest risk for the disease (CDC 2006; CDHS 2010). The risk for disseminated coccidioidomycosis is much higher among some ethnic groups, particularly African-Americans and Filipinos. In these ethnic groups, the risk for disseminated coccidioidomycosis is tenfold that of the general population (CDC 2006).

A VF website claims that most cases of valley fever do not require treatment. Even though 30-60% of the population in areas where the disease is highly prevalent - such as in the southern San Joaquin Valley of California - have positive skin tests indicating previous infection, most were unaware of ever having had valley fever ("Valley Fever Vaccine Project of the Americas" 2010).

Worker Safety Table 4
Disease Forms

CATEGORIES	NOTES
Asymptomatic	• Occurs in about 50% of patients
Acute Symptomatic	• Pulmonary syndrome that combines cough, chest pain, shortness of breath, fever, and fatigue. • Diffuse pneumonia affects immunosuppressed individuals • Skin manifestations include fine papular rash, erythema nodosum, and erythema multiforme • Occasional migratory arthralgias and fever
Chronic Pulmonary	• Affects between 5 to 10% of infected individuals • Usually presents as pulmonary nodules or peripheral thin-walled cavities
Extrapulmonary/Disseminated Varieties	
Chronic skin disease	• Keratotic and verrucose ulcers or subcutaneous fluctuant abscesses
Joints / Bones	• Severe synovitis and effusion that may affect knees, wrists, feet, ankles, and/or pelvis • Lytic lesions commonly affecting the axial skeleton
Meningeal Disease	• The most feared complication • Presenting with classic meningeal symptoms and signs • Hydrocephalus is a frequent complication
Others	• May affect virtually any organ, including thyroid, GI tract, adrenal glands, genitourinary tract, pericardium, peritoneum

Given the available scientific and medical literature on Valley Fever, it is difficult for staff to assess the potential for VF to impact workers during construction and operation of the proposed HECA facility with a reasonable degree of accuracy but given the scientific evidence to date, it is possible that the soils at the HECA site contain *c.immitis*. Furthermore, the higher number of cases reported in Kern County and recently in nearby San Luis Obispo County also indicate that the project site may have an elevated risk for exposure. To minimize potential exposure of workers and also the public to coccidioidomycosis during soil excavation and grading, extensive wetting of the soil prior to and during construction activities should be employed and dust masks should be worn at certain times during these activities. The dust (PM10) control measures found in the **Air Quality** section of this PSA/DEIS should be strictly adhered to in order to adequately reduce the risk of contracting VF to less than significant. Towards that, Energy Commission staff proposes Condition of Certification **WORKER SAFETY-7** which would require that the dust control measures found in proposed Conditions **AQ-SC3** and **AQ-SC4** be supplemented with additional requirements including the monitoring of airborne dust (PM_{10}) to ensure that dust control methods are effective.

Fire Hazards

During construction and operation of the proposed HECA there is the potential for small fires, major fires, and even explosions. Electrical sparks, combustion of fuel oil, hydraulic fluid, mineral oil, insulating fluid, or flammable liquids, explosions, and overheated equipment at the sulfur recovery unit, anhydrous ammonia storage tanks, the nitric acid storage tank, the gasifier, the UAN production plant, or the methanol storage tank, may cause small or large fires. Major fires in areas without or even with automatic fire detection and suppression systems are likely to occur at a facility that contains so many flammable liquids in such large volumes. A review of incidents at similar industrial sites is provided in the **Hazardous Materials Management** section of this PSA/DEIS. The list of accidents is illuminating and serves as a basis for precautions to be taken. Even fires and explosions due to the accidental rupture or failure of a natural gas pipeline can occur. Because of the complexity of this project, staff has determined that additional fire prevention and suppression methods are required in order to be in compliance with all LORS and has proposed a condition of certification to ensure additional protection from all fire hazards. These additional methods include the use of foam and more in-depth review of fire protection plans, as discussed below. Adoption of mitigation as described in proposed **WORKER SAFETY-8** would provide the KCFD with the resources it needs to effect these additional protections.

Staff reviewed the information provided in the AFC and contacted the KCFD to determine if available fire protection services and equipment would adequately protect workers, and to further determine the project's impact on fire protection services in the area. Staff met with the Kern County Fire Chief, Fire Marshall, and a Battalion Chief and toured all four fire stations that would respond to an emergency at the proposed project site. As a result of this meeting and tour, staff found that the HECA project would create direct and cumulative significant impacts on the KCFD but that these impacts could be mitigated to a less than significant level. Although the project will rely on both onsite fire protection systems and local fire protection services as described in the AFC (HECA 2012e, section 5.7.2.10), additional equipment and manpower is needed by the KCFD in order to adequately respond to a fire, rescue, hazardous material spill, or medical emergency and also not severely draw-down resources of the department thus leaving large areas of Kern County unprotected.

Emergency response will first be provided by crews for KCFD station 25 located in Buttonwillow. The station is staffed at all times with three firefighters (three shifts) and has one type-2 fire engine and one 4WD fire patrol vehicle. Staff drove the route to the project site at normal speed and found the roads narrow but suitable. According to the KCFD, the response time to the site from first notification at the fire station would be between 7 and 15 minutes. The next station that would respond is located in McKittrick (station 24) and it has the same staffing and equipment. The response time to the HECA site from first notification would be ~ 25-30 minutes. The third in line for response to the HECA site would be station 53 located on Highway 53 east of I-5. This station is proposed for re-location west of I-5 with an addition of a helipad. The fourth station that would respond is station 21 located in Taft. In addition to having one type-2 fire engine and one 4WD fire patrol vehicle, this station has a ladder truck (essential for fighting elevated fires and for rescue at elevations), six firefighters and a Battalion Chief.

Emergency Medical response (EMS) is provided by the KCFD. All firefighters are trained EMTs and a paramedic is located approximately one hour from the HECA site. Private ambulance service is available in both Buttonwillow and Taft.

First response to a hazardous materials spill is also provided by the KCFD and all firefighters are trained as HazMat Technicians.

The onsite fire protection system provides the first line of defense for small fires. In the event of a major fire, fire support services by trained firefighters and equipment for a sustained response would be provided by the KCFD.

Construction

During construction, the applicant has stated that portable fire extinguishers and small hose lines will be located and maintained throughout the site and some fixed firefighting equipment will be made available as soon as possible. Safety procedures and training will also be implemented (HECA 2012e, section 5.7.2.1). KCFD Station #25 in Buttonwillow will provide fire protection backup for larger fires that cannot be extinguished using the project's portable suppression equipment. The applicant intends to place into operation the permanent fire water loop and hydrants as soon as possible after construction begins (HECA 2012e, page 5.7-5) and staff encourages this action. However, staff believes that a firm date for the placement of a fire water loop is appropriate and thus proposes Condition of Certification **WORKER SAFETY-11** that would require placement of the fire water loop on the site not later than six months prior to the start of commissioning.

Operation

The information in the AFC indicates that the project intends to meet the fire protection and suppression requirements of the California Fire Code, all applicable recommended NFPA standards (including Standard 850, which addresses fire protection at electric generating plants), and all Cal-OSHA requirements. Fire suppression elements in the proposed plant will include both fixed and portable fire extinguishing systems. A dedicated supply of potable water will be stored on-site and will serve the fire loops, hydrants, sprinkler, and deluge systems. These will be placed in appropriate locations as per the California Fire Code and NFPA 850 (HECA 2012e, sections 2.5.11.1 and

2.5.11.2). In addition, fire-fighting foam equipment will be deployed near the methanol storage tanks and an automatic CO_2 extinguishing apparatus will be installed at the combustion turbine enclosure. The fire water loop pressure will be maintained by an electric jockey pump and back-up emergency diesel pump. Automatic fire suppression systems will be placed inside the control room, rack room, and the fire pump enclosure.

In addition to the fixed fire protection system, smoke detectors, flame detectors, high-temperature detectors, appropriate class of service portable extinguishers, and fire hydrants would be located throughout the facility at code-approved intervals. These systems are standard requirements of the fire code and NFPA. Staff has determined that they will ensure adequate fire protection.

The applicant would be required by Conditions of Certification **WORKER SAFETY-1** and**-2** to provide a final and more refined fire protection and prevention program to both staff and the KCFD prior to the construction and operation of the project for review in order to confirm the adequacy of proposed fire protection measures.

In conversations with the applicant, staff has been assured that the KCFD will have at least three secure access points though the perimeter fence into the facility. Both the California Fire Code (24 CCR Part 9, chapter 5, section 503.1.2) and NFPA require more than one access point for emergency responders. Therefore, staff proposes Condition of Certification **WORKER SAFETY-6** that would require the project owner to provide at least three secure access points to the site (one on each of the west, north, and east sides) for emergency vehicles and to equip these access gates with an acceptable entry system or keypad for fire department personnel to open the gate. As per staff's proposed condition addressing site security, the use of chains and padlocks to secure gates is prohibited (see the **Hazardous Materials Management** section of this PSA/DEIS, proposed condition **HAZ-7**).

Staff has discussed mitigation with the Kern County Fire Department and has received a list of needed capital and personnel improvements through the Kern County Planning Department (Kern County 2013b). The KCFD has requested that nine specific mitigation measures in the form of equipment and personnel be provided to mitigate direct and cumulative impacts on the fire department. The nine specific mitigation measures requested are summarized here:

1. Provide a fire-fighting foam pumper/tender.
2. Provide a fire protection specialist to be hired by the KCFD during the plan review process.
3. Purchase a plot of land for the relocation of KCFD station 53 and a helipad.
4. Provide 50% of the costs of a KCFD fire prevention inspector during the construction phase.
5. Provide the costs of training the crews at five fire stations who would respond to emergencies at the facility.
6. Purchase for the KCFD a fire rescue truck and a rotator crane to assist in vehicular accidents within Kern County.

7. Provide air monitoring equipment to the KCFD that will monitor multiple toxic gases.
8. Provide funds for six fire engineer positions needed to operate the foam pumper/tender.
9. Contribute annual funds to help maintain the reverse 9-1-1 system.

Staff has reviewed all the requests by the KCFD and had independently arrived at the same opinion for some of the requested mitigation. Staff has asked the KCFD to provide cost estimates of each suggested mitigation measure, but to-date, the county has provided some but not all those costs. However, staff is able to rely on its experience with other fire jurisdictions and propose a level of funding that is a reasonable estimate of what is required. Therefore, to address the direct incremental and cumulative impacts on the KCFD and to ensure that emergency response for fires, spills, rescue, and EMS are adequate, staff proposes Condition of Certification **WORKER SAFETY-8** which would require a one-time initial funding in the amount of $2,000,000 for capital improvements and other costs and $850,000 annually for operations and maintenance. The annual amount, however, would be off-set by the amount of property taxes paid each year by the HECA facility that would go to the Kern County Fire Department. Staff has learned that the usual and customary level of property taxes to be paid each year by an industrial facility that would go to the KCFD would be 10 percent of the total property taxes paid (personal communication with Kern County Fire Marshal Benny Wofford, April 2, 2013). In addition to the receipt of a certain portion of the annual property taxes, the KCFD has a fee schedule for plan review, permits, and inspections. However, since the initial one-time funding amount proposed by staff would cover the costs of these activities during construction and commissioning (a fire protection specialist for the plan review process and a fire prevention inspector during construction), it is expected that fees would not also be charged during this period. During operations, staff proposes that any usual and customary inspection fees charged by the KCFD be paid by the project owner.

Staff bases its proposed mitigation on several factors. First, the complexity of the proposed HECA facility, the use and storage of vast amounts of flammable and combustible materials, the relatively remote location, and the size of the industrial environment, all dictate the need for the following efforts to be undertaken by the KCFD:

1. Complex plan reviews;
2. Frequent hazmat and fire inspections;
3. Emergency Response including medical, fire, rescue, and hazardous materials incidents.

Second, standard fire department responses for a fire and for a hazmat spill include response from two fire stations and at least three fire fighters from each station. To fight a fire inside a structure, the KCFD must adhere to standard operating procedures and Cal-OSHA regulations that require “two men in”, “two men out”. Thus, a response of three fire fighters from one station would not allow fire fighters to attack a fire from within a structure or conduct a rescue. Confined space and collapsed trench rescues would also be problematic with only three fire fighters (although they could be accomplished as per Cal-OSHA requirements of “two in and one out”). Therefore, no matter what size the fire or how many workers are initially in need of rescue, the KCFD would dispatch engines from at least two fire stations so that at a minimum, six firefighters are sent to the scene. The issue of “draw-down” becomes a concern if two or more fire stations are dispatched to the HECA site. The community cannot be left without fire response and thus crews from other KCFD stations would be dispatched to cover the areas vacated by those going to aid at the HECA facility. Because of the very serious threat of escalation from a small incident to a much larger incident at the HECA facility, dispatch from more stations will be the rule rather than the exception and draw-down would occur more rapidly.

Third, it is very important to note that the HECA facility would be located in an area that has a rather harsh environment in the summer months. The ability of a fire fighter to perform duties while wearing a turn-out coat, heavy boots, and a respirator (self contained breathing apparatus) is limited under the best of circumstances. If conducting a rescue or fighting a fire that necessitates use of a respirator, the high-temperatures of the Tupman area (often approaching and exceeding 100° F), severely limits a fire fighter’s ability to perform the duties to 15 minutes at a time. This severe time restriction necessitates the mobilization of more fire fighters to respond to the emergency and hence more draw-down occurs.

Fourth, the KCFD lacks the specialized fire-fighting and rescue equipment (foam tender and rescue truck with a crane) and training to respond to emergencies at such a facility which does not now exist in California. Towards that, additional training is required and staff proposes **WORKER SAFETY-9** to require joint training with the HECA staff and the KCFD at least every two years.

All of the above necessitates a build-up of the KCFD’s ability to respond to the proposed facility. Staff has reviewed costs of equipment and fire fighters’ salaries (plus benefits) in other jurisdictions and arrived at an estimate of funds needed to provide necessary mitigation. The total amount is reflected in proposed condition **WORKER SAFETY-8**.

Emergency Medical Services Response

As described above, EMS is provided by the KCFD from several stations. All firefighters are trained EMTs and a paramedic is located approximately one hour from the HECA site. Private ambulance service is available in both Buttonwillow and Taft and medical air services are available by contract. However, the issue of increased vehicular (truck and tanker truck) activity on the roads and highways of Kern County going to and from the facility will undoubtedly increase the risk of vehicular accidents involving life-threatening injuries. The applicant has estimated that a total in excess of 36,000 single trips into and out of the facility will occur each year. The KCFD has noted that this significant increase in vehicle trips (mostly via truck and tanker trucks) will cause a significant impact on the EMS and rescue capability of the KCFD. Staff concurs with this opinion and supports mitigation to address this impact as described in number 6 above.

A statewide survey was conducted by staff and staff has determined that the potential for both work-related and non-work related heart attacks exists at power plants. In fact, staff’s research on the frequency of EMS response to gas-fired power plants shows that many of the responses for cardiac emergencies involved non-work related incidents, including visitors. The need for prompt response within a few minutes is well documented in the medical literature. Staff believes that the quickest medical intervention can only be achieved with the use of an on-site defibrillator often called an Automatic External Defibrillator or AED; the response from an off-site provider would take longer regardless of the provider location. This fact is also well documented and serves as the basis for many private and public locations including airports, factories, and government buildings, all of which maintain on-site cardiac defibrillation devices. Therefore, staff concludes that with the availability of modern cost-effective AED devices, it is proper in a power plant environment to maintain these devices on-site in order to treat cardiac arrythmias resulting from industrial accidents or other non-work related causes. Therefore, an additional condition of certification, **WORKER SAFETY-5**, is proposed so that a portable AED will be located on site, and workers trained in its use.

ENHANCED OIL RECOVERY FACILITY (EOR)

The Enhanced Oil Recovery (EOR) project at Occidental of Elk Hills, Inc. (OEHI) is located approximately four miles south of the proposed HECA project (OXY 2012). Carbon dioxide would be a byproduct at HECA and is proposed to be compressed and delivered by pipeline to the EOR project where it would be injected into the oil wells to help in the recovery of naturally trapped oil. The project is expected to result in the sequestration of approximately three (3) million tons of CO_2 per year during the demonstration phase. This rate of sequestration would also be required for the operational life of the power plant due to the requirements of California law (SB 1368) and the value created by the use of the CO_2 for EOR. The captured CO_2 would be compressed and transported via pipeline to the Elk Hills Oil Field. The CO_2 would enhance domestic oil production, contributing to the nation's energy security. An additional small amount of the CO_2 produced by the facility would be used to manufacture urea.

The EOR process involves the injection and reinjection of CO_2 to reduce the viscosity and enhance other properties of trapped oil in order to facilitate its flow through the reservoir, improving extraction. During EOR operations, the pore space left by the extracted oil is occupied by the injected CO_2, sequestering it in the geologic formation. EOR operations would be monitored to ensure that the injected CO_2 remains within the formation.

Staff met with the environmental and security personnel for Occidental Elk Hills, Inc. and reviewed the hazardous materials that would be used and stored at the EOR site and discussed fire protection measures. The OEHI property is protected by a private fire brigade with a mutual response agreement with the Kern County Fire Department. During construction and operations at the EOR facility, the site would have flow, pressure, and temperature monitoring devices, fire detection system sensing flame, leak detection sensing petroleum products, and have available a fire water supply tank of 1.5 million gallons. The CO_2 pipeline would for the most part be located underground and security at the two parts above ground where valve boxes exist would be surrounded by chain-link fence and since CO2 does not present a fire hazard, no fire detection or suppression equipment is required.

Staff concludes that given the on-site fire detection and suppression systems and the presence of a private fire brigade, emergency response to the EOR site for spills or fire would not have a significant impact on the Kern County Fire Department. Since mitigation is proposed to reduce the impacts on the KCFD from the HECA project site to an insignificant level, enhancements of the capabilities of the KCFD would also enhance response to the EOR site and therefore no additional conditions or mitigation is required.

CUMULATIVE IMPACTS AND MITIGATION

Staff reviewed what impacts the construction and operation of HECA could have on the fire and emergency service capabilities of the KCFD. Staff has identified both direct and cumulative impacts and mitigation to reduce those impacts to a level of less than significant. Staff's proposed Conditions of Certification **WORKER SAFETY-8** and **9** address both individual direct and cumulative impacts.

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Staff concludes that if all proposed conditions were adopted and implemented, the construction and operation of the HECA project would be in compliance with all applicable laws, ordinances, regulations, and standards (LORS) regarding long-term and short-term project impacts in the area of worker safety and fire protection.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

Comment: AIR (Association of Irritated Residents) provided a status report and data requests in a document dated November 2, 2012 (TN #68076). Residents asked about the dangers of anhydrous ammonia and if it is deadly. Several asked for more information on the possibility of accidents or releases at the project resulting in fatalities in nearby residents or workers (emphasis added), and accidents involving trucks transporting hazardous materials. They asked specifically how safe is it for someone to live or work nearby if there is a release of CO_2 or anhydrous ammonia, and are there other hazardous gases that might be released and cause harm. There was additional concern expressed regarding the potential for materials on-site to cause explosions and what impact that would have on the neighboring area. A question was raised as to whether the chemical factory will produce ammonium nitrate fertilizer and in what quantity and what security will HECA provide for storage and shipping of ammonium nitrate.

Response: Staff assessed these issues and its response can be seen in this section of the PSA/DEIS above and in the section addressing Hazardous Materials Management. In addition to the laws and regulations that must be followed by the project owner should this facility be licensed and built, staff has proposed seven conditions of certification that would, if adopted, increase the level of safety to workers. Worker safety plans would be prepared and reviewed and approved before workers would arrive on the site for either construction or operations.

Comment: The Kern County Fire Department has provided comments through the Kern County Planning Department (Kern County 2013b) and has requested that nine specific mitigation measures in the form of equipment and personnel be provided to mitigate direct and cumulative impacts on the fire department. The nine specific mitigation measures requested are summarized above.

Response: Staff considered all these issues and proposes mitigation as found in proposed condition **WORKER SAFETY-8** and ***9.***

CONCLUSIONS

Staff concludes that if the applicant for the proposed HECA project will provide project construction safety and health programs and project operations and maintenance safety and health programs, as required by Conditions of Certification **WORKER SAFETY -1**, and **-2**; and complies with the requirements of Conditions of Certification **WORKER SAFETY-3** through**-11**, HECA would incorporate sufficient measures to ensure adequate levels of industrial safety and fire protection and comply with applicable LORS. Staff also concludes that the proposed project would have significant impacts on local fire protection services but that implementation of staff's proposed conditions would reduce those impacts to less than significant.

DOE'S FINDINGS REGARDING DIRECT AND INDIRECT IMPACTS OF THE NO ACTION ALTERNATIVE

Under the No-Action Alternative, DOE would not provide financial assistance to the applicant for HECA. The applicant could still elect to construct and operate its project in the absence of financial assistance from DOE, but DOE believes this is unlikely. For the purposes of analysis in the PSA/DEIS, DOE assumes the project would not be constructed under the No-Action Alternative. Accordingly, the No-Action Alternative would have no impacts associated with this resource area.

PROPOSED CONDITIONS OF CERTIFICATION

WORKER SAFETY-1 The project owner shall submit to the compliance project manager (CPM) a copy of the Project Construction Safety and Health Program containing the following:

- A Construction Personal Protective Equipment Program;
- A Construction Exposure Monitoring Program;
- A Construction Injury and Illness Prevention Program;
- A Construction Emergency Action Plan; and
- A Construction Fire Prevention Plan.

The Personal Protective Equipment Program, the Exposure Monitoring Program, and the Injury and Illness Prevention Program shall be submitted to the CPM for review and approval concerning compliance of the program with all applicable safety orders. The Construction Emergency Action Plan and the Fire Prevention Plan shall be submitted to the Kern County Fire Department for review and comment prior to submittal to the CPM for approval.

Verification: At least thirty (30) days prior to the start of construction, the project owner shall submit to the CPM for review and approval a copy of the Project Construction Safety and Health Program. The project owner shall provide a copy of a letter to the CPM from the Kern County Fire Department stating the Fire Department's comments on the Construction Fire Prevention Plan and Emergency Action Plan.

WORKER SAFETY-2 The project owner shall submit to the CPM a copy of the Project Operations and Maintenance Safety and Health Program containing the following:

- An Operation Injury and Illness Prevention Plan;
- An Emergency Action Plan;
- Hazardous Materials Management Program;
- Fire Prevention Program (8 CCR § 3221); and;
- Personal Protective Equipment Program (8 CCR §§ 3401-3411).

The Operation Injury and Illness Prevention Plan, Emergency Action Plan, and Personal Protective Equipment Program shall be submitted to the CPM for review and approval concerning compliance of the program with all applicable Safety Orders. The Operation Fire Prevention Plan and the Emergency Action Plan shall also be submitted to the Kern County Fire Department for review and comment.

Verification: At least thirty (30) days prior to the start of first-fire or commissioning, the project owner shall submit to the CPM for approval a copy of the Project Operations and Maintenance Safety and Health Program. The project owner shall provide a copy of a letter to the CPM from the Kern County Fire Department stating the Fire Department's comments on the Operations Fire Prevention Plan and Emergency Action Plan.

WORKER SAFETY-3 The project owner shall provide a site Construction Safety Supervisor (CSS) who, by way of training and/or experience, is knowledgeable of power plant construction activities and relevant laws, ordinances, regulations, and standards, is capable of identifying workplace hazards relating to the construction activities, and has authority to take appropriate action to assure compliance and mitigate hazards. The CSS shall:

- Have over-all authority for coordination and implementation of all occupational safety and health practices, policies, and programs;
- Assure that the safety program for the project complies with Cal/OSHA and federal regulations related to power plant projects;
- Assure that all construction and commissioning workers and supervisors receive adequate safety training;
- Complete accident and safety-related incident investigations, emergency response reports for injuries, and inform the CPM of safety-related incidents; and

- Assure that all the plans identified in Worker Safety 1 and 2 are implemented.

Verification: At least thirty (30) days prior to the start of site mobilization, the project owner shall submit to the CPM the name and contact information for the Construction Safety Supervisor (CSS). The contact information of any replacement (CSS) shall be submitted to the CPM within one business day.

The CSS shall submit in the Monthly Compliance Report a monthly safety inspection report to include:

- Record of all employees trained for that month (all records shall be kept on site for the duration of the project);
- Summary report of safety management actions and safety-related incidents that occurred during the month;
- Report of any continuing or unresolved situations and incidents that may pose danger to life or health; and
- Report of accidents and injuries that occurred during the month.

WORKER SAFETY-4 The project owner shall make payments to the Chief Building Official (CBO) for the services of a Safety Monitor based upon a reasonable fee schedule to be negotiated between the project owner and the CBO. Those services shall be in addition to other work performed by the CBO. The Safety Monitor shall be selected by and report directly to the CBO, and shall be responsible for verifying that the Construction Safety Supervisor, as required in Worker Safety 3, implements all appropriate Cal/OSHA and Commission safety requirements. The Safety Monitor shall conduct on-site (including linear facilities) safety inspections at intervals necessary to fulfill those responsibilities.

Verification: At least thirty (30) days prior to the start of construction, the project owner shall provide proof of its agreement to fund the Safety Monitor services to the CPM for review and approval.

WORKER SAFETY-5 The project owner shall ensure that a portable automatic external defibrillator (AED) is located on site during construction and operations and shall implement a program to ensure that workers are properly trained in its use and that the equipment is properly maintained and functioning at all times. During construction and commissioning, the following persons shall be trained in its use and shall be on-site whenever the workers that they supervise are on-site: the Construction Project Manager or delegate, the Construction Safety Supervisor or delegate, and all shift foremen. During operations, all power plant employees shall be trained in its use. The training program shall be submitted to the CPM for review and approval.

Verification: At least thirty (30) days prior to the start of site mobilization the project owner shall submit to the CPM proof that a portable AED exists on site and a copy of the training and maintenance program for review and approval.

WORKER SAFETY-6 The project owner shall identify and provide at least three secure access points for emergency personnel to enter the site. These access points and the method of gate operation shall be submitted to the Kern County Fire Department for review and comment and to the CPM for review and approval.

Verification: At least sixty (60) days prior to the start of site mobilization, the project owner shall submit to the Kern County Fire Department and the CPM preliminary plans showing the location of at least three secure access points to the site and a description of how the gates will be opened by the fire department. At least thirty (30) days prior to the start of site mobilization, the project owner shall submit final plans to the CPM for review and approval. The final plan submittal shall also include a letter containing comments from the Kern County Fire Department or a statement that no comments were received.

WORKER SAFETY-7 The project owner shall develop and implement an enhanced Dust Control Plan that includes the requirements described in **AQ-SC3** and additionally requires:

i) site worker use of dust masks (NIOSH N-95 or better) whenever visible dust is present;

ii) implementation of enhanced dust control methods (increased frequency of watering, use of dust suppression chemicals, etc. consistent with **AQ-SC4**) immediately whenever visible dust comes from or onto the site

iii) no downwind PM_{10} ambient concentrations to increase more than 50 micrograms per cubic meter above upwind concentrations as determined by simultaneous upwind and downwind sampling. High-volume particulate matter samplers or other EPA-approved equivalent method(s) for PM_{10} monitoring shall be used. Samplers shall be:

a. Operated, maintained, and calibrated in accordance with 40 Code of Federal Regulations (CFR), Part 50, Appendix J, or appropriate EPA-published documents for EPA-approved equivalent methods(s) for PM_{10} sampling;

b. Reasonably placed upwind and downwind of the large operation based on prevailing wind direction and as close to the property line as feasible, such that other sources of fugitive dust between the sampler and the property line are minimized; and

c. Operated during active operations.

Verification: At least 60 days prior to the commencement of site mobilization, the enhanced Dust Control Plan shall be provided to the CPM for review and approval.

WORKER SAFETY-8 The project owner shall on the date of site mobilization, as mitigation for direct and cumulative impacts, make a one-time payment of $2,000,000 to the Kern County Fire Department for capital improvements. Also as mitigation, the project owner shall make an annual payment of

$850,000 for operations and maintenance commencing with the date of start of site mobilization and continuing annually thereafter on the anniversary until the final date of power plant decommissioning. The annual amount shall be off-set by the amount of property taxes paid each year by the HECA facility that would go to the Kern County Fire Department.

Verification: At least sixty (30) days prior to the start of site mobilization the project owner shall provide to the CPM documentation that the one-time capital improvement payment of $2,000,000 and the first annual payment of $850,000 have been paid to the KCFD, and shall also provide a statement in the Annual Compliance Report that subsequent annual payments (less the share of property taxes paid that go to the KCFD) have been made.

WORKER SAFETY-9 The project owner shall participate in joint training exercises with the Kern County Fire Department (KCFD) every two years.

Verification: At least 10 days prior to the start of commissioning, the project owner shall submit to the CPM proof that a joint training program with the KCFD is established. In the annual compliance report to the CPM, the project owner shall include the date, list of participants, training protocol, and location of the joint training.

WORKER SAFETY-10 The project owner shall ensure that during commissioning and operation, there shall be at least one person on site at all times (24 hours/day, 7 days/week) who shall be knowledgeable of and dedicated to safety, security, and fire protection.

Verification: At least 10 days prior to the start of commissioning, the project owner shall submit to the CPM proof that a competent person has been retained and will be on the site at all times. In the annual compliance report to the CPM, the project owner shall verify that the person was present.

WORKER SAFETY-11 The project owner shall place into operation the permanent fire water loop and hydrants as soon as possible after construction begins but in any event not later than six months (180 days) days prior to the start of commissioning.

Verification: At least six months (180 days) prior to the start of commissioning, the project owner shall submit to the CPM proof that the permanent fire water loop and hydrants have been built on-site, tested, and has received code approval from the CBO and review and comment from the KCFD.

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ENGINEERING ASSESSMENT

FACILITY DESIGN

Shahab Khoshmashrab

SUMMARY OF CONCLUSIONS

The California Energy Commission staff concludes that the design, construction, and eventual closure of the project and its linear facilities would likely comply with applicable engineering laws, ordinances, regulations and standards. The proposed conditions of certification, below, would ensure compliance with these laws, ordinances, regulations and standards.

INTRODUCTION

Facility design encompasses the civil, structural, mechanical, and electrical engineering design of the Hydrogen Energy California (HECA) project. The HECA project would consist of the feedstock handling block, fuel gasification block, syngas conditioning system, power generation block, fertilizer production complex, air separation unit, CO_2 transmission system, and enhanced oil recovery system. The purpose of this analysis is to:

- Verify that the laws, ordinances, regulations and standards (LORS) that apply to the engineering design and construction of the project have been identified;
- Verify that both the project and its ancillary facilities are sufficiently described, including proposed design criteria and analysis methods, in order to provide reasonable assurance that the project will be designed and constructed in accordance with all applicable engineering LORS, in a manner that also ensures the public health and safety;
- Determine whether special design features should be considered during final design to address conditions unique to the site which could influence public health and safety; and
- Describe the design review and construction inspection process and establish the conditions of certification used to monitor and ensure compliance with the engineering LORS, in addition to any special design requirements.

Subjects discussed in this analysis include:

- Identification of the engineering LORS that apply to facility design;
- Evaluation of the applicant’s proposed design criteria, including identification of criteria essential to public health and safety;
- Proposed modifications and additions to the application for certification (AFC) necessary for compliance with applicable engineering LORS; and
- Conditions of certification proposed by staff to ensure that the project will be designed and constructed to ensure public health and safety and comply with all applicable engineering LORS.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

Lists of LORS applicable to each engineering discipline (civil, structural, mechanical, and electrical) are described in the AFC (HECA 2012, AFC Appendix D). Key LORS are listed in **Facility Design Table 1,** below:

Facility Design Table 1
Key Engineering Laws, Ordinances, Regulations and Standards (LORS)

Applicable LORS	Description
Federal	Title 29 Code of Federal Regulations (CFR), Part 1910, Occupational Safety and Health standards
State	2010 (or the latest edition in effect) California Building Standards Code (CBSC) (also known as Title 24, California Code of Regulations)
Local	Kern County regulations and ordinances
General	American National Standards Institute (ANSI) American Society of Mechanical Engineers (ASME) American Welding Society (AWS) American Society for Testing and Materials (ASTM)

The following conditions of certification require the project to comply with the California Building Standards Code and Kern County regulations and ordinances to ensure that the project would be built to applicable engineering codes and ensure public health and safety.

For the project to be built in a manner that would ensure public health and safety and operational integrity of project equipment, the LORS listed above in **Facility Design Table 1** under the “**General**” heading, must also be met by the project. The LORS listed under this heading are only some of the key engineering standards applicable to the project; for a comprehensive list of engineering LORS, please see AFC Appendix D.

SETTING

HECA would be built on an approximately 453-acre site located in Kern County, California. For more information on the site and its related project description, please see the **Project Description** section of this document. Additional engineering design details are contained in the AFC, Appendix D (HECA 2012).

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

The purpose of this analysis is to ensure that the project would be built to applicable engineering codes and ensure public health and safety. This analysis further verifies that applicable engineering LORS have been identified and that the project and its ancillary facilities have been described in adequate detail. It also evaluates the applicant’s proposed design criteria, describes the design review and construction inspection process, and establishes conditions of certification that would monitor and ensure compliance with engineering LORS and any other special design requirements. These conditions allow both the California Energy Commission (Energy Commission) compliance project manager (CPM) and the applicant to adopt a compliance monitoring program that will verify compliance with these LORS.

SITE PREPARATION AND DEVELOPMENT

Staff has evaluated the proposed design criteria for grading, flood protection, erosion control, site drainage, and site access, in addition to the criteria for designing and constructing linear support facilities such as natural gas and electric transmission interconnections. The applicant proposes the use of accepted industry standards (see HECA 2012, Appendix D, for a representative list of applicable industry standards), design practices, and construction methods in preparing and developing the site. Staff concludes that this project, including its linear facilities, would most likely comply with all applicable site preparation LORS. To ensure compliance, staff proposes the conditions of certification listed below and in the **Geology and Paleontology** section of this document.

MAJOR STRUCTURES, SYSTEMS, AND EQUIPMENT

Major structures, systems, and equipment are structures and their associated components or equipment that are necessary for power production, costly or time consuming to repair or replace, are used for the storage, containment, or handling of hazardous or toxic materials, or could become potential health and safety hazards if not constructed according to applicable engineering LORS.

HECA will be designed and constructed to the 2010 California Building Standards Code (CBSC), also known as Title 24, California Code of Regulations, which encompasses the California Building Code (CBC), California Building Standards Administrative Code, California Electrical Code, California Mechanical Code, California Plumbing Code, California Energy Code, California Fire Code, California Code for Building Conservation, California Reference Standards Code, and other applicable codes and standards in effect when the design and construction of the project actually begin. If the initial designs are submitted to the chief building official (CBO) for review and approval after the update to the 2010 CBSC takes effect, the 2010 CBSC provisions shall be replaced with the updated provisions.

Certain structures in a power plant may be required, under the CBC, to undergo dynamic lateral force (structural) analysis; others may be designed using the simpler static analysis procedure. In order to ensure that structures are analyzed according to their appropriate lateral force procedure, staff has included condition of certification **STRUC-1**, below, which, in part, requires the project CBO's review and approval of the owner's proposed lateral force procedures before construction begins.

PROJECT QUALITY PROCEDURES

The applicant describes a quality program intended to inspire confidence that its systems and components will be designed, fabricated, stored, transported, installed, and tested in accordance with all appropriate power plant technical codes and standards (HECA 2012, AFC § 3.12.6, Appendix D). Compliance with design requirements will be verified through specific inspections and audits. Implementation of this quality assurance/quality control (QA/QC) program will ensure that HECA is actually designed, procured, fabricated, and installed as described in this analysis.

COMPLIANCE MONITORING

Under Section 104.1 of the 2010 CBC, the CBO is authorized and directed to enforce all provisions of the CBC. The Energy Commission itself serves as the building official, and has the responsibility to enforce the code, for all of the energy facilities it certifies. In addition, the Energy Commission has the power to interpret the CBC and adopt and enforce both rules and supplemental regulations that clarify application of the CBC's provisions.

The Energy Commission's design review and construction inspection process conforms to CBC requirements and ensures that all facility design conditions of certification are met. As provided by Section 103.3 of the 2010 CBC, the Energy Commission appoints experts to perform design review and construction inspections and act as delegate CBOs on behalf of the Energy Commission. These delegates may include the local building official and/or independent consultants hired to provide technical expertise that is not provided by the local official alone. The applicant, through permit fees provided by the CBC, pays the cost of these reviews and inspections. While building permits in addition to Energy Commission certification are not required for this project, the applicant pays in lieu of CBC permit fees to cover the costs of these reviews and inspections.

Engineering and compliance staff will invite Kern County or a third-party engineering consultant to act as CBO for this project. When an entity has been assigned CBO duties, Energy Commission staff will complete a memorandum of understanding (MOU) with that entity to outline both its roles and responsibilities and those of its subcontractors and delegates.

Staff has developed proposed conditions of certification to ensure for protection of public health and safety and compliance with engineering design LORS. Some of these conditions address the roles, responsibilities, and qualifications of the engineers who will design and build the proposed project (conditions of certification **GEN-1** through **GEN-8**). These engineers must be registered in California and sign and stamp every submittal of design plans, calculations, and specifications submitted to the CBO. These conditions require that every element of the project's construction (subject to CBO review and approval) be approved by the CBO before it is performed. They also require that qualified special inspectors perform or oversee special inspections required by all applicable LORS.

While the Energy Commission and delegate CBO have the authority to allow some flexibility in scheduling construction activities, these conditions are written so that no element of construction (of permanent facilities subject to CBO review and approval) which could be difficult to reverse or correct can proceed without prior CBO approval. Elements of construction that are not difficult to reverse may proceed without approval of the plans. The applicant bears the responsibility to fully modify construction elements in order to comply with all design changes resulting from the CBO's subsequent plan review and approval process.

FACILITY CLOSURE

The removal of a facility from service (decommissioning) when it reaches the end of its useful life ranges from “mothballing,” to the removal of all equipment and appurtenant facilities and subsequent restoration of the site. Future conditions that could affect decommissioning are largely unknown at this time.

In order to ensure that decommissioning will be completed in a manner that is environmentally sound, safe, and protects the public health and safety, the applicant shall submit to the Energy Commission for review and approval a contingency plan for unplanned closure prior to project operations, and a decommissioning plan before the project’s decommissioning begins. The plan shall include a discussion of:

- Proposed decommissioning activities for the project and all appurtenant facilities that were constructed as part of the project;
- All applicable LORS, local/regional plans, and proof of adherence to those applicable LORS and local/regional plans;
- The activities necessary to restore the site if the plan requires removal of all equipment and appurtenant facilities; and
- Decommissioning alternatives other than complete site restoration.

Satisfying the above requirements should serve as adequate protection, even in the unlikely event that the project is abandoned. Staff has proposed general conditions (see **Compliance Conditions**) to ensure that these measures are included in the Facility Closure Plan.

DOE’S FINDINGS REGARDING DIRECT AND INDIRECT IMPACTS OF THE NO-ACTION ALTERNATIVE

Under the No-Action Alternative, DOE would not provide financial assistance to the applicant for HECA. The applicant could still elect to construct and operate its project in the absence of financial assistance from DOE, but DOE believes this is unlikely. For the purposes of analysis in the PSA/DEIS, DOE assumes the project would not be constructed under the No-Action Alternative. Accordingly, the No-Action Alternative would have no impacts associated with this resource area.

CONCLUSIONS AND RECOMMENDATIONS

1. The laws, ordinances, regulations and standards (LORS) identified in the AFC and supporting documents directly apply to the project.

2. Staff has evaluated the proposed engineering LORS, design criteria, and design methods in the record, and concludes that the design, construction, and eventual closure of the project will likely comply with applicable engineering LORS.

3. The proposed conditions of certification will ensure that HECA is designed and constructed in accordance with applicable engineering LORS. This will be

accomplished through design review, plan checking, and field inspections that will be performed by the CBO or other Energy Commission delegate. Staff will audit the CBO to ensure satisfactory performance.

4. Though future conditions that could affect decommissioning are largely unknown at this time, it can reasonably be concluded that if the project owner submits a decommissioning plan as required in the **Compliance Conditions** portion of this document prior to decommissioning, decommissioning procedures will comply with all applicable engineering LORS.

Energy Commission staff recommends that:

1. The proposed conditions of certification be adopted to ensure that the project is designed and constructed in a manner that protects the public health and safety and complies with all applicable engineering LORS;

2. The project be designed and built to the 2010 CBSC (or successor standards, if in effect when initial project engineering designs are submitted for review); and

3. The CBO reviews the final designs, checks plans, and performs field inspections during construction. Energy Commission staff shall audit and monitor the CBO to ensure satisfactory performance.

Under the No-Action Alternative, DOE would not provide financial assistance to the Applicant for the HECA Project. The Applicant could still elect to construct and operate its project in the absence of financial assistance from DOE, but DOE believes this is unlikely. For the purposes of analysis in the PSA/DEIS, DOE assumes the project would not be constructed under the No-Action Alternative. Accordingly, the No-Action Alternative would have no impacts associated with this resource area.

CONDITIONS OF CERTIFICATION

GEN-1 The project owner shall design, construct, and inspect the project in accordance with the 2010 California Building Standards Code (CBSC), also known as Title 24, California Code of Regulations, which encompasses the California Building Code (CBC), California Building Standards Administrative Code, California Electrical Code, California Mechanical Code, California Plumbing Code, California Energy Code, California Fire Code, California Code for Building Conservation, California Reference Standards Code, and all other applicable engineering LORS (including the applicable Kern County engineering LORS) in effect at the time initial design plans are submitted to the CBO for review and approval (the CBSC in effect is the edition that has been adopted by the California Building Standards Commission and published at least 180 days previously). The project owner shall ensure that all the provisions of the above applicable codes are enforced during the construction, addition, alteration, moving, demolition, repair, or maintenance of the completed facility. All transmission facilities (lines, switchyards, switching stations and substations) are covered in the conditions of certification in the **Transmission System Engineering** section of this document.

In the event that the initial engineering designs are submitted to the CBO when the successor to the 2010 CBSC is in effect, the 2010 CBSC provisions shall be replaced with the applicable successor provisions. Where, in any specific case, different sections of the code specify different materials, methods of construction or other requirements, the most restrictive shall govern. Where there is a conflict between a general requirement and a specific requirement, the specific requirement shall govern.

The project owner shall ensure that all contracts with contractors, subcontractors, and suppliers clearly specify that all work performed and materials supplied comply with the codes listed above.

Verification: Within 30 days following receipt of the certificate of occupancy for any increment of construction, the project owner shall submit to the CPM a statement of verification, signed by the responsible design engineer, attesting that all designs, construction, installation, and inspection requirements of the applicable LORS and the Energy Commission's decision have been met in the area of facility design for that increment of construction. The project owner shall provide the CPM a copy of the certificate of occupancy within 30 days of receipt from the CBO.

Once the certificate of occupancy has been issued for any portion(s) of the completed facility, the project owner shall inform the CPM at least 30 days prior to any construction, addition, alteration, moving, demolition, repair, or maintenance to be performed on that portion(s) of the completed facility, if it requires CBO approval for compliance with the above codes. The CPM will then determine if the CBO needs to approve the work.

GEN-2 Before submitting the initial engineering designs for CBO review, the project owner shall furnish the CPM and the CBO with a schedule of facility design submittals, and master drawings and master specifications list. The master drawings and master specifications list shall contain a list of proposed submittal packages of designs, calculations, and specifications for major structures, systems, and equipment. Major structures, systems, and equipment are structures and their associated components or equipment that are necessary for power production, costly or time consuming to repair or replace, are used for the storage, containment, or handling of hazardous or toxic materials, or could become potential health and safety hazards if not constructed according to applicable engineering LORS. The schedule shall contain the date of each submittal to the CBO. To facilitate audits by Energy Commission staff, the project owner shall provide specific packages to the CPM upon request.

Verification: At least 60 days (or a project owner- and CBO-approved alternative time frame) prior to the start of rough grading, the project owner shall submit to the CBO and to the CPM the schedule, and the master drawings and master specifications list of documents to be submitted to the CBO for review and approval. These documents shall be the pertinent design documents for the major structures, systems, and equipment defined above in Condition of Certification **GEN-2**. Major structures and equipment shall be added to or deleted from the list only with CPM approval. The project owner shall provide schedule updates in the monthly compliance report.

GEN-3 The project owner shall make payments to the CBO for design review, plan checks, and construction inspections, based upon a reasonable fee schedule to be negotiated between the project owner and the CBO. These fees may be consistent with the fees listed in the 2010 CBC, adjusted for inflation and other appropriate adjustments; may be based on the value of the facilities reviewed; may be based on hourly rates; or may be otherwise agreed upon by the project owner and the CBO.

Verification: The project owner shall make the required payments to the CBO in accordance with the agreement between the project owner and the CBO. The project owner shall send a copy of the CBO's receipt of payment to the CPM in the next monthly compliance report indicating that applicable fees have been paid.

GEN-4 Prior to the start of rough grading, the project owner shall assign a California-registered architect, or a structural or civil engineer, as the resident engineer (RE) in charge of the project. All transmission facilities (lines, switchyards, switching stations, and substations) are addressed in the conditions of certification in the **Transmission System Engineering** section of this document.

The RE may delegate responsibility for portions of the project to other registered engineers. Registered mechanical and electrical engineers may be delegated responsibility for mechanical and electrical portions of the project, respectively. A project may be divided into parts, provided that each part is clearly defined as a distinct unit. Separate assignments of general responsibility may be made for each designated part.

The RE shall:

1. Monitor progress of construction work requiring CBO design review and inspection to ensure compliance with LORS;
2. Ensure that construction of all facilities subject to CBO design review and inspection conforms in every material respect to applicable LORS, these conditions of certification, approved plans, and specifications;
3. Prepare documents to initiate changes in approved drawings and specifications when either directed by the project owner or as required by the conditions of the project;
4. Be responsible for providing project inspectors and testing agencies with complete and up-to-date sets of stamped drawings, plans, specifications, and any other required documents;
5. Be responsible for the timely submittal of construction progress reports to the CBO from the project inspectors, the contractor, and other engineers who have been delegated responsibility for portions of the project; and

6. Be responsible for notifying the CBO of corrective action or the disposition of items noted on laboratory reports or other tests when they do not conform to approved plans and specifications.

The resident engineer (or his delegate) must be located at the project site, or be available at the project site within a reasonable period of time, during any hours in which construction takes place.

The RE shall have the authority to halt construction and to require changes or remedial work if the work does not meet requirements.

If the RE or the delegated engineers are reassigned or replaced, the project owner shall submit the name, qualifications and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer.

<u>Verification:</u> At least 30 days (or project owner- and CBO-approved alternative time frame) prior to the start of rough grading, the project owner shall submit to the CBO, for review and approval, the resume and registration number of the RE and any other delegated engineers assigned to the project. The project owner shall notify the CPM of the CBO's approvals of the RE and other delegated engineer(s) within five days of the approval.

If the RE or the delegated engineer(s) is subsequently reassigned or replaced, the project owner has five days to submit the resume and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer within five days of the approval.

GEN-5 Prior to the start of rough grading, the project owner shall assign at least one of each of the following California registered engineers to the project: a civil engineer; a soils, geotechnical, or civil engineer experienced and knowledgeable in the practice of soils engineering; and an engineering geologist. Prior to the start of construction, the project owner shall assign at least one of each of the following California registered engineers to the project: a design engineer who is either a structural engineer or a civil engineer fully competent and proficient in the design of power plant structures and equipment supports; a mechanical engineer; and an electrical engineer. (California Business and Professions Code section 6704 et seq., and sections 6730, 6731 and 6736 require state registration to practice as a civil engineer or structural engineer in California). All transmission facilities (lines, switchyards, switching stations, and substations) are handled in the conditions of certification in the **Transmission System Engineering** section of this document.

The tasks performed by the civil, mechanical, electrical, or design engineers may be divided between two or more engineers, as long as each engineer is responsible for a particular segment of the project (for example, proposed earthwork, civil structures, power plant structures, equipment support). No segment of the project shall have more than one responsible engineer. The transmission line may be the responsibility of a separate California registered electrical engineer.

The project owner shall submit, to the CBO for review and approval, the names, qualifications, and registration numbers of all responsible engineers assigned to the project.

If any one of the designated responsible engineers is subsequently reassigned or replaced, the project owner shall submit the name, qualifications and registration number of the newly assigned responsible engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer.

A. The civil engineer shall:
   1. Review the foundation investigations, geotechnical, or soils reports prepared by the soils engineer, the geotechnical engineer, or by a civil engineer experienced and knowledgeable in the practice of soils engineering;
   2. Design (or be responsible for the design of), stamp, and sign all plans, calculations, and specifications for proposed site work, civil works, and related facilities requiring design review and inspection by the CBO. At a minimum, these include: grading, site preparation, excavation, compaction, construction of secondary containment, foundations, erosion and sedimentation control structures, drainage facilities, underground utilities, culverts, site access roads and sanitary sewer systems; and
   3. Provide consultation to the RE during the construction phase of the project and recommend changes in the design of the civil works facilities and changes to the construction procedures.

B. The soils engineer, geotechnical engineer, or civil engineer experienced and knowledgeable in the practice of soils engineering, shall:
   1. Review all the engineering geology reports;
   2. Prepare the foundation investigations, geotechnical, or soils reports containing field exploration reports, laboratory tests, and engineering analysis detailing the nature and extent of the soils that could be susceptible to liquefaction, rapid settlement or collapse when saturated under load;
   3. Be present, as required, during site grading and earthwork to provide consultation and monitor compliance with requirements set forth in the 2010 CBC (depending on the site conditions, this may be the responsibility of either the soils engineer, the engineering geologist, or both); and
   4. Recommend field changes to the civil engineer and RE.

This engineer shall be authorized to halt earthwork and to require changes if site conditions are unsafe or do not conform to the predicted conditions used as the basis for design of earthwork or foundations.

C. The engineering geologist shall:

1. Review all the engineering geology reports and prepare a final soils grading report; and
2. Be present, as required, during site grading and earthwork to provide consultation and monitor compliance with the requirements set forth in the 2010 CBC (depending on the site conditions, this may be the responsibility of either the soils engineer, the engineering geologist, or both).

D. The design engineer shall:

1. Be directly responsible for the design of the proposed structures and equipment supports;
2. Provide consultation to the RE during design and construction of the project;
3. Monitor construction progress to ensure compliance with engineering LORS;
4. Evaluate and recommend necessary changes in design; and
5. Prepare and sign all major building plans, specifications, and calculations.

E. The mechanical engineer shall be responsible for, and sign and stamp a statement with, each mechanical submittal to the CBO, stating that the proposed final design plans, specifications, and calculations conform to all of the mechanical engineering design requirements set forth in the Energy Commission's decision.

F. The electrical engineer shall:

1. Be responsible for the electrical design of the project; and
2. Sign and stamp electrical design drawings, plans, specifications, and calculations.

<u>Verification:</u> At least 30 days (or project owner- and CBO-approved alternative time frame) prior to the start of rough grading, the project owner shall submit to the CBO for review and approval, resumes and registration numbers of the responsible civil engineer, soils (geotechnical) engineer and engineering geologist assigned to the project.

At least 30 days (or project owner- and CBO-approved alternative time frame) prior to the start of construction, the project owner shall submit to the CBO for review and approval, resumes and registration numbers of the responsible design engineer, mechanical engineer, and electrical engineer assigned to the project.

The project owner shall notify the CPM of the CBO's approvals of the responsible engineers within five days of the approval.

If the designated responsible engineer is subsequently reassigned or replaced, the project owner has five days in which to submit the resume and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer within five days of the approval.

GEN-6 Prior to the start of an activity requiring special inspection, including prefabricated assemblies, the project owner shall assign to the project, qualified and certified special inspector(s) who shall be responsible for the special inspections required by the 2010 CBC. All transmission facilities (lines, switchyards, switching stations, and substations) are handled in conditions of certification in the **Transmission System Engineering** section of this document.

A certified weld inspector, certified by the American Welding Society (AWS), and/or American Society of Mechanical Engineers (ASME) as applicable, shall inspect welding performed on-site requiring special inspection (including structural, piping, tanks and pressure vessels).

The special inspector shall:

1. Be a qualified person who shall demonstrate competence, to the satisfaction of the CBO, for inspection of the particular type of construction requiring special or continuous inspection;
2. Inspect the work assigned for conformance with the approved design drawings and specifications;
3. Furnish inspection reports to the CBO and RE. All discrepancies shall be brought to the immediate attention of the RE for correction, then, if uncorrected, to the CBO and the CPM for corrective action; and
4. Submit a final signed report to the RE, CBO, and CPM, stating whether the work requiring special inspection was, to the best of the inspector's knowledge, in conformance with the approved plans, specifications, and other provisions of the applicable edition of the CBC.

<u>Verification:</u> At least 15 days (or project owner- and CBO-approved alternative time frame) prior to the start of an activity requiring special inspection, the project owner shall submit to the CBO for review and approval, with a copy to the CPM, the name(s) and qualifications of the certified weld inspector(s), or other certified special inspector(s) assigned to the project to perform one or more of the duties set forth above. The project owner shall also submit to the CPM a copy of the CBO's approval of the qualifications of all special inspectors in the next monthly compliance report.

If the special inspector is subsequently reassigned or replaced, the project owner has five days in which to submit the name and qualifications of the newly assigned special inspector to the CBO for approval. The project owner shall notify the CPM of the CBO's approval of the newly assigned inspector within five days of the approval.

GEN-7 If any discrepancy in design and/or construction is discovered in any engineering work that has undergone CBO design review and approval, the project owner shall document the discrepancy and recommend required corrective actions. The discrepancy documentation shall be submitted to the CBO for review and approval. The discrepancy documentation shall reference this condition of certification and, if appropriate, applicable sections of the CBC and/or other LORS.

Verification: The project owner shall transmit a copy of the CBO's approval of any corrective action taken to resolve a discrepancy to the CPM in the next monthly compliance report. If any corrective action is disapproved, the project owner shall advise the CPM, within five days, of the reason for disapproval and the revised corrective action to obtain CBO's approval.

GEN-8 The project owner shall obtain the CBO's final approval of all completed work that has undergone CBO design review and approval. The project owner shall request the CBO to inspect the completed structure and review the submitted documents. The project owner shall notify the CPM after obtaining the CBO's final approval. The project owner shall retain one set of approved engineering plans, specifications, and calculations (including all approved changes) at the project site or at another accessible location during the operating life of the project. Electronic copies of the approved plans, specifications, calculations, and marked-up as-builts shall be provided to the CBO for retention by the CPM.

Verification: Within 15 days of the completion of any work, the project owner shall submit to the CBO, with a copy to the CPM, in the next monthly compliance report, (a) a written notice that the completed work is ready for final inspection, and (b) a signed statement that the work conforms to the final approved plans. After storing the final approved engineering plans, specifications, and calculations described above, the project owner shall submit to the CPM a letter stating both that the above documents have been stored and the storage location of those documents.

Within 90 days of the completion of construction, the project owner shall provide to the CBO three sets of electronic copies of the above documents at the project owner's expense. These are to be provided in the form of "read only" (Adobe .pdf 6.0 or newer version) files, with restricted (password-protected) printing privileges, on archive quality compact discs.

CIVIL-1 The project owner shall submit to the CBO for review and approval the following:

1. Design of the proposed drainage structures and the grading plan;
2. An erosion and sedimentation control plan;
3. A construction storm water pollution prevention plan (SWPPP);
4. Related calculations and specifications, signed and stamped by the responsible civil engineer; and

5. Soils, geotechnical, or foundation investigations reports required by the 2010 CBC.

Verification: At least 15 days (or project owner- and CBO-approved alternative time frame) prior to the start of site grading the project owner shall submit the documents described above to the CBO for design review and approval. In the next monthly compliance report following the CBO's approval, the project owner shall submit a written statement certifying that the documents have been approved by the CBO.

CIVIL-2 The resident engineer shall, if appropriate, stop all earthwork and construction in the affected areas when the responsible soils engineer, geotechnical engineer, or the civil engineer experienced and knowledgeable in the practice of soils engineering identifies unforeseen adverse soil or geologic conditions. The project owner shall submit modified plans, specifications, and calculations to the CBO based on these new conditions. The project owner shall obtain approval from the CBO before resuming earthwork and construction in the affected area.

Verification: The project owner shall notify the CPM within 24 hours, when earthwork and construction is stopped as a result of unforeseen adverse geologic/soil conditions. Within 24 hours of the CBO's approval to resume earthwork and construction in the affected areas, the project owner shall provide to the CPM a copy of the CBO's approval.

CIVIL-3 The project owner shall perform inspections in accordance with the 2010 CBC. All plant site-grading operations, for which a grading permit is required, shall be subject to inspection by the CBO.

If, in the course of inspection, it is discovered that the work is not being performed in accordance with the approved plans, the discrepancies shall be reported immediately to the resident engineer, the CBO, and the CPM. The project owner shall prepare a written report, with copies to the CBO and the CPM, detailing all discrepancies, non-compliance items, and the proposed corrective action.

Verification: Within five days of the discovery of any discrepancies, the resident engineer shall transmit to the CBO and the CPM a non-conformance report (NCR), and the proposed corrective action for review and approval. Within five days of resolution of the NCR, the project owner shall submit the details of the corrective action to the CBO and the CPM. A list of NCRs, for the reporting month, shall also be included in the following monthly compliance report.

CIVIL-4 After completion of finished grading and erosion and sedimentation control and drainage work, the project owner shall obtain the CBO's approval of the final grading plans (including final changes) for the erosion and sedimentation control work. The civil engineer shall state that the work within his/her area of responsibility was done in accordance with the final approved plans.

Verification: Within 30 days (or project owner- and CBO-approved alternative time frame) of the completion of the erosion and sediment control mitigation and drainage work, the project owner shall submit to the CBO, for review and approval, the final grading plans (including final changes) and the responsible civil engineer's signed statement that the installation of the facilities and all erosion control measures were completed in accordance with the final approved combined grading plans, and that the facilities are adequate for their intended purposes, along with a copy of the transmittal letter to the CPM. The project owner shall submit a copy of the CBO's approval to the CPM in the next monthly compliance report.

STRUC-1 Prior to the start of any increment of construction, the project owner shall submit plans, calculations and other supporting documentation to the CBO for design review and acceptance for all project structures and equipment identified in the CBO-approved master drawing and master specifications lists. The design plans and calculations shall include the lateral force procedures and details as well as vertical calculations.

Construction of any structure or component shall not begin until the CBO has approved the lateral force procedures to be employed in designing that structure or component.

The project owner shall:

1. Obtain approval from the CBO of lateral force procedures proposed for project structures;
2. Obtain approval from the CBO for the final design plans, specifications, calculations, soils reports, and applicable quality control procedures. If there are conflicting requirements, the more stringent shall govern (for example, highest loads, or lowest allowable stresses shall govern). All plans, calculations, and specifications for foundations that support structures shall be filed concurrently with the structure plans, calculations, and specifications;
3. Submit to the CBO the required number of copies of the structural plans, specifications, calculations, and other required documents of the designated major structures prior to the start of on-site fabrication and installation of each structure, equipment support, or foundation;
4. Ensure that the final plans, calculations, and specifications clearly reflect the inclusion of approved criteria, assumptions, and methods used to develop the design. The final designs, plans, calculations, and specifications shall be signed and stamped by the responsible design engineer; and
5. Submit to the CBO the responsible design engineer's signed statement that the final design plans conform to applicable LORS.

Verification: At least 60 days (or project owner- and CBO-approved alternative time frame) prior to the start of any increment of construction of any structure or component listed in the CBO-approved master drawing and master specifications list, the project owner shall submit to the CBO the above final design plans, specifications and calculations, with a copy of the transmittal letter to the CPM.

The project owner shall submit to the CPM, in the next monthly compliance report, a copy of a statement from the CBO that the proposed structural plans, specifications, and calculations have been approved and comply with the requirements set forth in applicable engineering LORS.

STRUC-2 The project owner shall submit to the CBO the required number of sets of the following documents related to work that has undergone CBO design review and approval:

1. Concrete cylinder strength test reports (including date of testing, date sample taken, design concrete strength, tested cylinder strength, age of test, type and size of sample, location and quantity of concrete placement from which sample was taken, and mix design designation and parameters);
2. Concrete pour sign-off sheets;
3. Bolt torque inspection reports (including location of test, date, bolt size, and recorded torques);
4. Field weld inspection reports (including type of weld, location of weld, inspection of non-destructive testing (NDT) procedure and results, welder qualifications, certifications, qualified procedure description or number (ref: AWS); and
5. Reports covering other structural activities requiring special inspections shall be in accordance with the 2010 CBC.

Verification: If a discrepancy is discovered in any of the above data, the project owner shall, within five days, prepare and submit an NCR describing the nature of the discrepancies and the proposed corrective action to the CBO, with a copy of the transmittal letter to the CPM. The NCR shall reference the condition(s) of certification and the applicable CBC chapter and section. Within five days of resolution of the NCR, the project owner shall submit a copy of the corrective action to the CBO and the CPM.

The project owner shall transmit a copy of the CBO's approval or disapproval of the corrective action to the CPM within 15 days. If disapproved, the project owner shall advise the CPM, within five days, the reason for disapproval, and the revised corrective action to obtain CBO's approval.

STRUC-3 The project owner shall submit to the CBO design changes to the final plans required by the 2010 CBC, including the revised drawings, specifications, calculations, and a complete description of, and supporting rationale for, the proposed changes, and shall give to the CBO prior notice of the intended filing.

Verification: On a schedule suitable to the CBO, the project owner shall notify the CBO of the intended filing of design changes, and shall submit the required number of sets of revised drawings and the required number of copies of the other above-mentioned documents to the CBO, with a copy of the transmittal letter to the CPM. The project owner shall notify the CPM, via the monthly compliance report, when the CBO has approved the revised plans.

STRUC-4 Tanks and vessels containing quantities of toxic or hazardous materials exceeding amounts specified in the 2010 CBC shall, at a minimum, be designed to comply with the requirements of that chapter.

Verification: At least 30 days (or project owner- and CBO-approved alternate time frame) prior to the start of installation of the tanks or vessels containing the above specified quantities of toxic or hazardous materials, the project owner shall submit to the CBO for design review and approval final design plans, specifications, and calculations, including a copy of the signed and stamped engineer's certification.

The project owner shall send copies of the CBO approvals of plan checks to the CPM in the following monthly compliance report. The project owner shall also transmit a copy of the CBO's inspection approvals to the CPM in the monthly compliance report following completion of any inspection.

MECH-1 The project owner shall submit, for CBO design review and approval, the proposed final design, specifications and calculations for each plant major piping and plumbing system listed in the CBO-approved master drawing and master specifications list. The submittal shall also include the applicable QA/QC procedures. Upon completion of construction of any such major piping or plumbing system, the project owner shall request the CBO's inspection approval of that construction.

The responsible mechanical engineer shall stamp and sign all plans, drawings, and calculations for the major piping and plumbing systems, subject to CBO design review and approval, and submit a signed statement to the CBO when the proposed piping and plumbing systems have been designed, fabricated, and installed in accordance with all of the applicable laws, ordinances, regulations and industry standards, which may include, but are not limited to:

- American National Standards Institute (ANSI) B31.1 (Power Piping Code);
- ANSI B31.2 (Fuel Gas Piping Code);
- ANSI B31.3 (Chemical Plant and Petroleum Refinery Piping Code);
- ANSI B31.8 (Gas Transmission and Distribution Piping Code);
- NACE R.P. 0169-83;
- NACE R.P. 0187-87;
- NFPA 56;
- Title 24, California Code of Regulations, Part 5 (California Plumbing Code);
- Title 24, California Code of Regulations, Part 6 (California Energy Code, for building energy conservation systems and temperature control and ventilation systems);
- Title 24, California Code of Regulations, Part 2 (California Building Code); and

- Kern County codes.

  The CBO may deputize inspectors to carry out the functions of the code enforcement agency.

Verification: At least 30 days (or project owner- and CBO-approved alternative time frame) prior to the start of any increment of major piping or plumbing construction listed in the CBO-approved master drawing and master specifications list, the project owner shall submit to the CBO for design review and approval the final plans, specifications, and calculations, including a copy of the signed and stamped statement from the responsible mechanical engineer certifying compliance with applicable LORS, and shall send the CPM a copy of the transmittal letter in the next monthly compliance report.

The project owner shall transmit to the CPM, in the monthly compliance report following completion of any inspection, a copy of the transmittal letter conveying the CBO's inspection approvals.

MECH-2 For all pressure vessels installed in the plant, the project owner shall submit to the CBO and California Occupational Safety and Health Administration (Cal-OSHA), prior to operation, the code certification papers and other documents required by applicable LORS. Upon completion of the installation of any pressure vessel, the project owner shall request the appropriate CBO and/or Cal-OSHA inspection of that installation.

The project owner shall:

1. Ensure that all boilers and fired and unfired pressure vessels are designed, fabricated, and installed in accordance with the appropriate section of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, or other applicable code. Vendor certification, with identification of applicable code, shall be submitted for prefabricated vessels and tanks; and
2. Have the responsible design engineer submit a statement to the CBO that the proposed final design plans, specifications, and calculations conform to all of the requirements set forth in the appropriate ASME Boiler and Pressure Vessel Code or other applicable codes.

Verification: At least 30 days (or project owner- and CBO-approved alternative time frame) prior to the start of on-site fabrication or installation of any pressure vessel, the project owner shall submit to the CBO for design review and approval, the above listed documents, including a copy of the signed and stamped engineer's certification, with a copy of the transmittal letter to the CPM.

The project owner shall transmit to the CPM, in the monthly compliance report following completion of any inspection, a copy of the transmittal letter conveying the CBO's and/or Cal-OSHA inspection approvals.

MECH-3 The project owner shall submit to the CBO for design review and approval the design plans, specifications, calculations, and quality control procedures for any heating, ventilating, air conditioning (HVAC) or refrigeration system.

Packaged HVAC systems, where used, shall be identified with the appropriate manufacturer's data sheets.

The project owner shall design and install all HVAC and refrigeration systems within buildings and related structures in accordance with the CBC and other applicable codes. Upon completion of any increment of construction, the project owner shall request the CBO's inspection and approval of that construction. The final plans, specifications and calculations shall include approved criteria, assumptions, and methods used to develop the design. In addition, the responsible mechanical engineer shall sign and stamp all plans, drawings and calculations and submit a signed statement to the CBO that the proposed final design plans, specifications and calculations conform with the applicable LORS.

Verification: At least 30 days (or project owner- and CBO-approved alternative time frame) prior to the start of construction of any HVAC or refrigeration system, the project owner shall submit to the CBO the required HVAC and refrigeration calculations, plans, and specifications, including a copy of the signed and stamped statement from the responsible mechanical engineer certifying compliance with the CBC and other applicable codes, with a copy of the transmittal letter to the CPM.

ELEC-1 Prior to the start of any increment of electrical construction for all electrical equipment and systems 110 Volts or higher (see a representative list, below) the project owner shall submit, for CBO design review and approval, the proposed final design, specifications, and calculations. Upon approval, the above listed plans, together with design changes and design change notices, shall remain on the site or at another accessible location for the operating life of the project. The project owner shall request that the CBO inspect the installation to ensure compliance with the requirements of applicable LORS. All transmission facilities (lines, switchyards, switching stations, and substations) are handled in conditions of certification in the **Transmission System Engineering** section of this document.

A. Final plant design plans shall include:

1. one-line diagram for the 13.8 kV, 4.16 kV and 480 V systems;
2. system grounding drawings;
3. lightning protection system; and
4. hazard area classification plan.

B. Final plant calculations must establish:

1. short-circuit ratings of plant equipment;
2. ampacity of feeder cables;
3. voltage drop in feeder cables;
4. system grounding requirements;

5. coordination study calculations for fuses, circuit breakers and protective relay settings for the 13.8 kV, 4.16 kV and 480 V systems;
6. system grounding requirements;
7. lighting energy calculations; and
8. 110 volt system design calculations and submittals showing feeder sizing, transformer and panel load confirmation, fixture schedules and layout plans.

C. The following activities shall be reported to the CPM in the monthly compliance report:

1. Receipt or delay of major electrical equipment;
2. Testing or energization of major electrical equipment; and
3. A signed statement by the registered electrical engineer certifying that the proposed final design plans and specifications conform to requirements set forth in the Energy Commission decision.

Verification: At least 30 days (or project owner- and CBO-approved alternative time frame) prior to the start of each increment of electrical construction, the project owner shall submit to the CBO for design review and approval the above listed documents. The project owner shall include in this submittal a copy of the signed and stamped statement from the responsible electrical engineer attesting compliance with the applicable LORS, and shall send the CPM a copy of the transmittal letter in the next monthly compliance report.

REFERENCES

HECA 2012 – Hydrogen California LLC, 08-AFC-8A. Amended Application for Certification, Volumes 1, 2, and 3 dated May 02, 2012. Submitted to CEC/Docket Unit on May 02, 2012.

GEOLOGY AND PALEONTOLOGY

Casey Weaver, C.E.G.

SUMMARY OF CONCLUSIONS

The proposed Hydrogen Energy California (HECA) project is located in an active geologic area of the southern Great Valley geomorphic province in western Kern County, California. Because of its geologic setting, the site could be subject to moderate to high levels of earthquake-related ground shaking. Significant thicknesses of expansive clay soils are also present at the surface. The effects of strong ground shaking and expansive soils must be mitigated, to the extent practical, through structural designs required by the California Building Code (CBC 2010) and the project geotechnical report. CBC 2010 requires that structures be designed to resist seismic stresses from ground acceleration and, to a lesser extent, liquefaction potential. The design-level geotechnical investigation required for the project by the CBC, proposed Condition of Certification **GEO- 1** in this section and Conditions of Certification **GEN-1**, **GEN-5** and **CIVIL-1**, presented in the **Facility Design** section of this document, address standard engineering design recommendations for mitigation of seismic shaking and adverse site soil conditions.

There are no known viable geologic or mineralogical resources at the site, with the exception of the oil and gas fields of the Naval Petroleum Reserve. Paleontological resources have been documented regionally within Quaternary alluvium and Tertiary Tulare Formation, similar to deposits that underlie the project site. Numerous new fossil localities were discovered by the applicant during cursory field explorations at the proposed plant site. Potential impacts would be mitigated through worker training and monitoring by qualified paleontologists, as required by Conditions of Certification, **PAL-1** through **PAL-7**.

The proposed Occidental of Elk Hills, Inc., (OEHI) component of HECA is located in the Elk Hills Oil Field (EHOF). The EHOF is located near the southwestern edge of the San Joaquin Valley, approximately 25 miles southwest of the city of Bakersfield in Kern County, California. The EHOF is located on the topographic expression of the northwest trending linear Elk Hills Anticline. The Elk Hills Anticline is a large compound fold structure approximately 17 miles long and over 7 miles wide. Because of its geologic setting, the site could be subject to moderate to high levels of earthquake-related ground shaking. The effects of strong ground shaking must be mitigated, to the extent practical, through structural designs required by the California Building Code (CBC 2010) and the project geotechnical report. CBC 2010 requires that structures be designed to resist seismic stresses from ground acceleration and, to a lesser extent, liquefaction potential. The design-level geotechnical investigation required for the project by the CBC, and recommended mitigation measures **OEHI GEO- 1** in this section and recommended mitigation measures **GEN-1**, **GEN-5** and **CIVIL-1**, presented in the **Facility Design** section of this document, address standard engineering design recommendations for mitigation of seismic shaking and adverse site soil conditions.

Regarding viable geologic or mineralogical resources at the site, the site is underlain by the oil and natural gas fields of the Naval Petroleum Reserve. Active oil and gas production is ongoing at the project site.

The applicant assessed domestic mines within the Western United States capable of providing the quantity and quality of required solid feedstocks. Coal sourced from New Mexico, Utah, and Colorado was among the analyzed alternatives. Based on these alternatives the project currently plans to use Western sub-bituminous coal from New Mexico.

The applicant has not selected a limestone supplier yet, but it is anticipated that fluxant would be shipped from a distribution center in Riverside, California.

Paleontological resources have been documented regionally within Quaternary alluvium and Tertiary Tulare Formation, similar to deposits that underlie the project site. Potential impacts could be mitigated through worker training and monitoring by qualified paleontologists, as presented in the recommended mitigation measures **OEHI PAL-1** through **OEHI PAL-7**.

Based on the information summarized above, Energy Commission staff believes that the potential adverse cumulative impacts to project facilities from geologic hazards during its design life, if any, would be less than significant. Similarly, staff believes the potential adverse cumulative impacts to potential geologic, mineralogic, and paleontologic resources from the construction, operation, and closure of the proposed project, if any, would be less than significant. It is staff's opinion that the proposed HECA can be designed and constructed in accordance with all applicable laws, ordinances, regulations, and standards (LORS), and in a manner that both protects environmental quality and assures public safety.

INTRODUCTION

Hydrogen Energy California, LLC, (HECA) is proposing an integrated gasification combined cycle (IGCC) polygeneration project (HECA or Project). The Project would gasify a fuel blend of 75 percent coal and 25 percent petroleum coke (petcoke) to produce synthesis gas (syngas). Syngas produced via gasification would be purified to hydrogen-rich fuel, and the project proposes to generate between 405 and 431 MW gross or an average of 416MW gross electrical power and between 151 to 266 MW net after accounting for onsite auxiliary power loads in a combined-cycle power block, low-carbon, nitrogen-based products in an integrated manufacturing complex, and carbon dioxide (CO_2) for use in enhanced oil recovery (EOR). CO_2 from HECA would be transported by pipeline for use in EOR in the adjacent Elk Hills Oil Field (EHOF), which is owned and operated by Occidental of Elk Hills, Inc. (OEHI). The EOR process results in sequestration (storage) of the CO_2. This introduction provides brief descriptions of both HECA and the OEHI component.

Terms used throughout this section are defined as follows:

- **Project or HECA.** The HECA IGCC electrical generation facility, low-carbon nitrogen based products manufacturing complex, and associated equipment and processes, including its linear facilities.

- **Project Site or HECA Project Site.** The 453-acre parcel of land on which the HECA IGCC electrical generation facility, low-carbon nitrogen-based products manufacturing complex, and associated equipment and processes (excluding off-site portions of linear facilities), would be located.
- **OEHI Component.** The use of CO_2 for EOR at the EHOF and resulting sequestration, including the CO_2 pipeline, EOR processing facility, and associated equipment.
- **OEHI Component Site.** The portion of land within the EHOF on which the OEHI Component would be located and where the CO_2 produced by HECA would be used for EOR and resulting sequestration**.**
- **Controlled Area.** The 653 acres of land adjacent to the Project Site over which HECA would control access and future land uses.

The various project elements of the combined project are discussed below:

HECA Project Site
The HECA project includes a 453-acre parcel of land on which the HECA IGCC electrical generation facility, low-carbon nitrogen-based products manufacturing complex, and associated equipment and processes.

HECA Project Linear Facilities
The HECA project includes the following linear facilities, which extend off the HECA project site:

- **Electrical transmission line.** An approximately 2-mile-long electrical transmission line would interconnect the Project to a future Pacific Gas and Electric Company (PG&E) switching station east of the Project Site.
- **Natural gas supply pipeline.** An approximately 13-mile-long natural gas interconnection would be made with PG&E natural gas pipelines located north of the Project Site.
- **Water supply pipelines and wells.** An approximately 15-mile-long process water supply line and up to five new groundwater wells would be installed by the Buena Vista Water Storage District (BVWSD) to supply brackish groundwater from northwest of the Project Site. An approximately 1-mile-long water supply line from the West Kern Water District (WKWD) east of the Project Site would provide potable water.
- **Coal transportation.** HECA is considering two alternatives for transporting coal to the Project Site:
  - **Alternative 1, rail transportation.** An approximately 5-mile-long new industrial railroad spur that would connect the Project Site to the existing San Joaquin Valley Railroad (SJVRR) Buttonwillow railroad line, north of the Project Site. This railroad spur would also be used to transport some HECA products to market.
  - **Alternative 2, truck transportation.** An approximately 27-mile-long truck transport route via existing roads from an existing coal transloading facility northeast of the Project Site.

OEHI Component

OEHI would be installing the CO_2 pipeline from the Project Site to the EHOF, as well as installing the EOR Processing Facility, including any associated wells and pipelines needed in the EHOF for CO_2 EOR and sequestration. The following is a brief description of the OEHI component:

- — **CO_2 EOR Processing Facility.** The CO_2 EOR Processing Facility and 13 satellites are expected to occupy approximately 136 acres within the EHOF. The facility would use 720 producing and injection wells: 570 existing wells and 150 new well installations. Approximately 652 miles of new pipeline would also be installed in the EHOF.
- — **CO_2 pipeline.** An approximately 3-mile-long 12" diameter CO_2 pipeline would transfer the CO_2 from the HECA Project Site south to the OEHI CO_2 EOR Processing Facility.

The OEHI component does not fall under the jurisdiction of the Energy Commission. However it is considered part of the whole of the HECA project. Therefore, its effect on the environment is also analyzed in this document.

Occidental of Elk Hills, Inc. (OEHI) is proposing to extend the life of the enhanced oil recovery (EOR) operations by utilizing carbon dioxide (CO_2) to facilitate oil production from its Elk Hills Oil Field (EHOF) operations. This is known as the OEHI CO_2 EOR project. The carbon dioxide used by OEHI would be sourced from HECA. HECA would be located approximately four miles north of the EHOF and would generate CO_2 from an integrated gasification combined cycle (IGCC) power plant. HECA would utilize technology capable of capturing over 90 percent of the CO_2 produced during HECA facility operations. This CO_2 would be compressed and delivered via pipeline to OEHI's EOR Processing Facility. The OEHI CO_2 EOR component is expected to receive an annual average rate of 107 million standard cubic feet per day (mmscfd) of CO_2 (approximately 2.6 million tons per year). The planned injection process would be reviewed as a part of the OEHI permitting process with Department of Conservation, Division of Oil, Gas and Geothermal Resources (DOGGR). During all phases of this project, OEHI must comply with Underground Injection Control (UIC) Class II regulations enforced by DOGGR.

CO_2 from HECA would be transported via pipeline to the EOR Processing Facility, at which point the CO_2 would be distributed to CO_2 injection wells placed in a geometric pattern designed to optimize the recovery of oil from the reservoir.

For each injection well there may be three or more nearby production wells where produced fluids are pumped to the surface and then transported by pipeline in a closed loop system to a centralized collection and processing facility. Typically, these wells are arranged in a consistent geometrical pattern with an injection well in the center and production wells on the perimeter. For example, in a five spot pattern, there would be four production wells on the four corners of a square geometric pattern, with a single injection well in the center of the pattern. The pattern of injection and production wells may change over time, and is typically based on predictive computer simulations that model reservoir performance based on reservoir characterization and historical operations.

At the surface, the recovered fluids would be transferred to a separator at the EOR Processing Facility where the oil, water, and natural gas would be separated. The natural gas would contain CO_2 as the injected gas begins to break through at the production wells. Separated natural gas would enter a pipeline for transport to the existing gas processing facility in Section 35R of the EHOF where it is combined and processed with other produced gas from the field for sale to customers. The CO_2 would be separated from the produced natural gas and CO_2 would then be recompressed for reinjection along with CO_2 purchased from HECA to further optimize the CO_2 EOR process.

In the section provided below, Energy Commission staff discusses the potential impacts of HECA development on geologic, mineralogic, and paleontologic resources as well as impacts on the proposed HECA site from potential geologic hazards. Staff's objective is to identify resources that could be significantly adversely affected, evaluate the potential of the project construction and operation to significantly impact the resources and provide mitigation measures as necessary to ensure that there would be no significant adverse impacts to geological and paleontological resources during the project construction, operation, and closure and to ensure that operation of the plant would not expose occupants to high-probability geologic hazards. A brief geological and paleontological overview is provided. The section concludes with staff's proposed conditions of certification - *i.e.*, monitoring and mitigation measures that, if implemented, would reduce any project impacts to geologic, mineralogic, and paleontologic resources or threat from geologic hazards to less than significant levels.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Applicable laws, ordinances, regulations, and standards (LORS) are listed in the application for certification (AFC) (HEI 2008c). The following briefly describes the current LORS for both geologic hazards and resources and mineralogic and paleontologic resources.

Geology and Paleontology Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	The proposed project is not located on federal land. There are no federal LORS for geologic hazards and resources for this site.
State	
California Building Code (2010)	The California Building Code (CBC 2010) includes a series of standards that are used in project investigation, design, and construction (including seismicity, grading and erosion control). The CBC has adopted provisions in the International Building Code (IBC, 2009).

Applicable Law	Description
Alquist-Priolo Earthquake Fault Zoning Act, Public Resources Code (PRC), section 2621–2630	Mitigates against surface fault rupture of known active faults beneath occupied structures. Requires disclosure to potential buyers of existing real estate and a 50-foot setback for new occupied buildings. No portions of the site and proposed ancillary facilities are located within designated Alquist-Priolo Earthquake Fault Zones (EFZ).
The Seismic Hazards Mapping Act, PRC Section 2690–2699	Areas are identified that are subject to the effects of strong ground shaking, such as liquefaction, landslides, tsunamis, and seiches.
Applicable Standard (General)	**Description**
PRC, Chapter 1.7, sections 5097.5 and 30244	Regulates removal of paleontological resources from state lands, defines unauthorized removal of fossil resources as a misdemeanor, and requires mitigation of disturbed sites.
Warren-Alquist Act, PRC, sections 25527 and 25550.5(i)	The Warren-Alquist Act requires the Energy Commission to "give the greatest consideration to the need for protecting areas of critical environmental concern, including, but not limited to, unique and irreplaceable scientific, scenic, and educational wildlife habitats; unique historical, archaeological, and cultural sites…" With respect to paleontologic resources, the Energy Commission relies on guidelines from the Society for Vertebrate Paleontology.
Society for Vertebrate Paleontology (SVP), 1995	The "Measures for Assessment and Mitigation of Adverse Impacts to Non-Renewable Paleontological Resources: Standard Procedures" is a set of procedures and standards for assessing and mitigating impacts to vertebrate paleontological resources. The measures were adopted in October 1995 by the SVP, a national organization of professional scientists.
Bureau of Land Management (BLM) Instructional Memorandum 2008-009	Provides up-to-date methodologies for assessing paleontological sensitivity and management guidelines for paleontological resources on lands managed by the Bureau of Land Management. Staff also uses this methodology for non BLM lands as it provides a more detailed categorization of paleontological sensitivity than what is provided by SVP.
Local	
Kern County General Plan	The Kern County General Plan contains policies, goals, and implementation measures that address physical and environmental constraints, seismic hazards and landslides and, in areas of known paleontological resources, addresses the preservation of these resources where feasible.

To simplify the understanding of this Geology and Paleontology analysis, this section is broken into a discussion of HECA followed by a discussion of the OEHI Component

HECA SETTING

HECA would be constructed on 453 acres of privately owned land located approximately 7 miles west of the western border of the city of Bakersfield and 1.5 miles northwest of the unincorporated community of Tupman in west-central Kern County, California (**Geology and Paleontology Figure 1**). The proposed project site is currently used for irrigated agricultural production.

HECA would be a base load power generating facility that proposes to generate between 405 and 431 MW gross or an average of 416MW gross electrical power and between 151 to 266 MW net after accounting for onsite auxiliary power loads. Ancillary facilities would include a 13-mile natural gas pipeline, a 2-mile above-ground electrical transmission connection to the existing PG&E electrical grid west of the site, a 15-mile brackish water process supply pipeline, a 1-mile-long potable water supply pipeline, and a 3-mile-long carbon dioxide pipeline. Other onsite improvements would include a process water treatment plant, a petroleum coke (petcoke)/coal gasification facility, control and administrative buildings, a zero liquid discharge system for treatment of process water, and various smaller outbuildings and facilities. Carbon dioxide produced by petcoke and/or coal gasification would be compressed and pumped to the nearby Elk Hills petroleum production field for enhancing oil recovery and ultimate sequestration (HEI 2008c).

REGIONAL SETTING

The proposed HECA site is located in the southern San Joaquin Valley, which is part of the Great Valley geomorphic province of California (**Geology and Paleontology Figure 2**). The Great Valley is approximately 400 miles long and 60 miles wide, bounded on the north by low-lying hills; on the northeast by the volcanic plateau of the Cascade Range; on the west by the Coast Ranges; on the east by the Sierra Nevada; and on the south by the Coast Ranges and the Tehachapi Mountains. The northern one-third of the Great valley is known as the Sacramento Valley, whereas the southern two-thirds is known as the San Joaquin Valley. The boundary between the two sub-basins is located at the confluence of the Sacramento and San Joaquin Rivers in the delta area near Suisun Bay and the city of Stockton (USGS 1986). The Great Valley is characterized by dissected uplands, and relatively undeformed low alluvial plains and fans, river flood plains and channels, and lake bottoms. In the late Cenozoic era much of the San Joaquin Valley was occupied by shallow brackish and freshwater lakes. Much of the valley fill alluvium is underlain by marine and non-marine sedimentary rocks and crystalline basement which have undergone anticlinal and synclinal folding and faulting related to regional tectonism. Major oil fields, pooled in antiformal structures associated with this regional tectonic activity, have been developed in the southern portion of the San Joaquin Valley.

PROJECT SITE DESCRIPTION

The proposed HECA site would consist of land that has been extensively disturbed by agricultural activities for at least the past 50 years. Elevations on the property range from roughly 282 to 291 feet above mean sea level (msl). Located at approximately 35.33 degrees north latitude by 119.39 degrees west longitude, the majority of the proposed project site is in Section 10, Township 34 South, Range 24 East of the Mount Diablo Baseline and Meridian in western Kern County, near the city of Bakersfield. The 453-acre site is approximately 2.25 miles west and one mile south of the intersection of Interstate 5 and Bellevue Road.

The proposed project site lies on the northeastern flank of the Elk Hills anticline, a structural fold which is part of a series of fold and thrust complexes that mark the southern boundary of the Great Valley geomorphic province **(Geology and Paleontology Figure 2)**. Surface soils are composed of Quaternary (Holocene) age alluvial gravel and sand deposits of the Kern River Valley (Dibblee 2005a; URS 2009a) (**Geology and Paleontology Figure 3)**. Alluvium, shed from the Elk Hills southwest of the HECA site, is likely interbedded with fluvial sands and gravels associated with the Kern River and its tributaries. The alluvial fan deposits are underlain by Pliocene to Pleistocene age non-marine clastic sediments of the Tulare Formation, which extend to depths in excess of 1,000 feet below the surface (Page 1983; Dibblee 2005a). In the Elk Hills where the Tulare Formation is exposed, both upper and lower members are present. The entire HECA site and a majority of the project linears lie in areas mapped as Quaternary alluvial fan deposits. Only the southern portions of the carbon dioxide pipelines extend into areas of the northern Elk Hills mapped as Tulare Formation. Both upper and lower members are crossed, as well as a one-meter thick marker bed known as the Lower limestone, which is a white to light grey, marly carbonate deposited in fresh water (Dibblee 2005a).

The proposed HECA plant site and project linears are not crossed by any known active faults and do not lie within a designated Alquist-Priolo Earthquake Fault Zone (CGS 2008). A number of major, active faults lie within 70 miles of the site. These faults are discussed in detail under the **Geological Hazards** section later in this section of staff's assessment.

The preliminary geotechnical report for the proposed site (HEI 2008a) indicates that 1.5 to 6 feet of uncontrolled silty sand fill was encountered in borings in the northwest, northeast, and southeast corners of the property. Undisturbed native surface soils are composed of fine-grained sandy lean and fat clays and sandy silts that extend to depths of 8 to 19 feet. The clay soils contain medium to high plasticity fines with moderate expansion indices. The fine-grained sediments were not identified as Quaternary alluvium or Tulare Formation in the project geotechnical report, but the materials were probably deposited in distal alluvial fan, lacustrine, and/or fluvial environments that are consistent with either unit. Dibblee (2005a) indicates that Quaternary alluvium is Holocene in age, but depth to underlying Pleistocene sediments is undetermined. Silty sand and poorly graded sand designated as Tulare Formation underlies fine-grained soils, and extends to the maximum depth of drilling at 101.5 feet (URS 2009a). The upper portions are medium dense, and become dense to very dense with depth.

The depth to ground water measured in local wells ranged from 19.3 feet below ground surface (bgs) to 35 feet bgs (URS 2009a). However, during the preliminary site geotechnical investigation, ground water was not encountered to the maximum depth of drilling at 101.5 feet bgs (URS 2009a). Water levels beneath the site likely vary seasonally and with pumping frequency of nearby irrigation wells.

Existing grade at the proposed power plant site slopes approximately 1% to the northeast (USGS 1954). Site drainage is probably by a combination of infiltration and overland sheet flow. A more complete discussion of on-site drainage is included in the **Soils and Surface Water** section of this staff assessment.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

This section considers two types of impacts. The first is the potential impacts the proposed facility could have on existing geologic, mineralogic, and paleontologic resources in the area. The second is the potential geologic hazards that could adversely impact the proper functioning of the proposed facility and create life/safety concerns.

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

As discussed in the Introduction section of this document, this assessment analyzes the project's impacts pursuant to both the National Environmental Policy Act (NEPA) and the California Environmental Quality Act (CEQA). The two statutes are similar in their requirements concerning analysis of a project's impacts. Therefore, unless otherwise noted, staff's use of, and reference to, CEQA criteria and guidelines also encompasses and satisfies NEPA requirements for this environmental document.

The CEQA guidelines, Appendix G, provide a checklist of questions that lead agencies typically address when assessing impacts related to geologic and mineralogic resources, and effects of geologic hazards.

- Section (V) (c) includes guidelines that determine if a project will either directly or indirectly destroy a unique paleontological resource or site, or a unique geological feature.
- Sections (VI) (a), (b), (c), (d), and (e) focus on whether or not the project would expose persons or structures to geologic hazards.
- Sections (XI) (a) and (b) concern the project's effects on mineral resources.

To assess potential impacts on unique geologic features and effects on mineral resources, staff has reviewed geologic and mineral resource maps for the surrounding area, as well as site-specific information provided by the applicant, to determine if geologic and mineralogic resources exist in the area.

To assess potential impacts on paleontological resources, staff reviewed existing paleontologic information and requested records searches from the Natural History Museum of Los Angeles County (LACM) for the site area. Site-specific information generated by the applicant for the proposed site and ancillary facilities was also reviewed (HEI 2008c, Appendix Q). All research was conducted in accordance with accepted assessment protocol (SVP 1995) to determine whether any known paleontologic resources exist in the general area. If present or likely to be present, conditions of certification that outline required procedures to mitigate impacts to potential resources are proposed as part of the requirements for project approval.

DIRECT/INDIRECT IMPACTS AND MITIGATION

An assessment of the potential impacts to geologic, mineralogic, and paleontologic resources, and from geologic hazards is provided below. The assessment of impacts is followed by a summary of potential impacts that may occur during construction and operation of the project and provides recommended conditions of certification that would ensure potential impacts are mitigated to a level that is less than significant. The recommended conditions of certification would allow the Energy Commission's compliance project manager (CPM) and the applicant to adopt a compliance monitoring scheme ensuring ongoing compliance with LORS applicable to geologic hazards and the protection of geologic, mineralogic, and paleontologic resources.

GEOLOGIC AND MINERALOGIC RESOURCES

The proposed HECA site is not located within an established Mineral Resource Zone (MRZ) and no economically viable mineral deposits are known to be present (CDMG 1990; CDMG 1998; CDMG 1999). The site would be in close proximity to several producing oil and gas fields of the regional Naval Petroleum Reserve, including the Elk Hills, North Coles Levee and South Coles Levee oil fields (Dibblee 2005a). The California Division of Oil, Gas, and Geothermal Resources (DOGGR) identifies a single well within the proposed project area that reportedly did not encounter significant oil or gas deposits. Although discovery of a petroleum resource beneath the HECA plant site is unlikely, directional drilling techniques could allow for exploitation of a resource from outside of the project boundaries. Therefore, the potential for impacting future petroleum production from beneath the site is considered to be low. Petroleum and gas fields underlie portions of the proposed project linears, but their presence is not likely to affect current or future recovery of petroleum reserves.

PALEONTOLOGIC RESOURCES

Staff reviewed correspondence from the LACM (McLeod 2009), and the confidential Paleontological Resources Technical Report (HEI 2008c) for information regarding known fossil localities and stratigraphic unit sensitivity within the proposed project area. The proposed HECA plant site is underlain to depths of 8 to 19 feet by fine-grained sediments that belong to Quaternary alluvial, fluvial and/or lacustrine deposits. Quaternary alluvium is known regionally to contain significant fossil resources, primarily terrestrial vertebrates, and is considered to be highly sensitive (HEI 2008c). Sensitivity increases with depth, according to McLeod (2009), although a depth at which higher sensitivity older allumium would be encountered was not specified. Remains of an extinct species of horse have been recovered along the Bakersfield Canal, and fossil wood is common. Freshwater invertebrate shells and ichnofossils (trace fossils) were identified in Quaternary alluvium at several localities within one mile of the proposed site and project linears during the field survey conducted for the Paleontological Resources Technical Report attached to the AFC (HEI 2008c, Appendix Q). The low energy environment of deposition for the fine-grained soils underlying the proposed site increases the potential for preservation of significant fossil remains.

The potential for a geologic unit on a site to yield scientifically significant, nonrenewable paleontological resources is referred to as its paleontological sensitivity (SVP 1995). Paleontological sensitivity is a qualitative assessment made by a professional paleontologist taking into account the paleontological potential of the stratigraphic units present, the local geology and geomorphology, and any other local factors that may suggest a probability of encountering fossils. According to the Society of Vertebrate Paleontology standard guidelines, sensitivity comprises (1) the potential for a geological unit to yield abundant or significant vertebrate fossils or for yielding a few significant fossils, large or small, vertebrate, invertebrate, or paleobotanical remains, and (2) the importance of recovered evidence for new and significant taxonomic, phylogenetic, paleoecological, or stratigraphic data (SVP 1995). The Bureau of Land Management has developed a potential fossil yield classification system that offers a more detailed system of evaluating the likelihood that a given geological unit may yield fossils (BLM and Chirstensen 2007). This system is described in detail, and also summarized in **Geology and Paleontology Table 2**.

Geology and Paleontology Table 2
SVP Paleontological Sensitivity Ratings (Sensitivity) and Equivalent Potential Fossil Yield Classifications (PFYC) Consistent with BLM Guidelines

Sensitivity (PFYC)	Definition
High and Very High (PFYC 4, 5)	Assigned to geological formations known to contain paleontological resources that include rare, well-preserved, and/or fossil materials important to on-going paleoclimatic, paleobiological and/or evolutionary studies. They have the potential to produce, or have produced vertebrate remains that are the particular research focus of many paleontologists, and can represent important educational resources as well.
Moderate and Unknown (PFYC 3a, 3b)	Stratigraphic units that have yielded fossils that are moderately well-preserved, are common elsewhere, and/or that are stratigraphically long-ranging would be assigned a moderate rating. This evaluation can also be applied to strata that have an unproven but strong potential to yield fossil remains based on its stratigraphy and/or geomorphologic setting.
Low (PFYC 2)	Sediment that is relatively recent, or that represents a high-energy subaerial depositional environment where fossils are unlikely to be preserved. A low abundance of invertebrate fossil remains, or reworked marine shell from other units, can occur but the paleontological sensitivity would remain low due to their lack of potential to serve significant scientific or educational purposes.
Very Low and Zero (PFYC 1)	Stratigraphic units with very low potential include pyroclastic flows and sediments heavily altered by pedogenesis. Most igneous rocks have zero paleontological potential. Other stratigraphic units deposited subaerially in a high energy environment (such as alluvium) may also be assigned a marginal or zero sensitivity rating. Manmade fill is also considered to possess zero (no) paleontological potential.

Pliocene to Pleistocene age Tulare Formation, which underlies the fine-grained sediments has a high sensitivity rating and high potential to contain significant fossil resources. Previously recorded localities from the unit include remains of a wide variety of vertebrate species, as well as freshwater invertebrates and fossil wood. A locality south of one of the carbon dioxide pipeline alternatives yielded fossil remains of rabbit and camel (McLeod 2009). Examination of exposures of the Tulare Formation during the field survey for the Paleontological Resources Technical Report revealed previously unknown occurrences of vertebrate bones, invertebrate shells and fossilized wood within one mile of the site (HEI 2008c, Appendix Q).

Recent, uncontrolled fill is present locally on the proposed site to depths of 1.5 to 6 feet. The material, where encountered, is considered to have no potential for producing meaningful fossils because any fossil remains discovered will be out of their natural geologic context. Similarly, a large portion of the proposed site has been disturbed during agricultural operations, so the upper 1 to 2 feet of the surface is also unlikely to contain significant paleontological resources.

Overall, staff considers the probability that paleontological resources would be encountered during site construction activities to be high. The potential for exposure of paleontological resources would increase with depth and volume of proposed construction excavations. This assessment is based on SVP criteria and the confidential paleontological report appended to the AFC (HEI 2008c). Proposed Conditions of Certification **PAL-1** to **PAL-7** are designed to mitigate paleontological resource impacts, as discussed above, to less than significant levels. These conditions essentially require a worker education program in conjunction with the monitoring of earthwork activities by a qualified professional paleontological resources specialist (PRS).

The proposed conditions of certification allow the Energy Commission's compliance project manager (CPM) and the applicant to adopt a compliance monitoring scheme ensuring compliance with LORS applicable to geologic hazards and the protection of paleontologic resources.

GEOLOGICAL HAZARDS

The AFC (HEI 2008c) provides documentation of potential geologic hazards at the proposed site, including site-specific subsurface information generated by a preliminary geotechnical investigation (HEI 2008c, Appendix P). Review of the AFC, coupled with staff's independent research, indicates that the potential for geologic hazards to impact the proposed plant site during its practical design life would be low if recommendations for mitigation of seismic shaking and expansive soils are adopted and followed. Geologic hazards related to seismic shaking and adverse soil conditions are addressed in a project geotechnical report per CBC (2010) requirements (HEI 2008c, Appendix P).

Staff's independent research included the review of available geologic maps, reports, and related data of the proposed HECA site. Staff's analysis of this information is provided below.

Faulting and Seismicity

Energy Commission staff reviewed numerous CGS, USGS, and other publications, (CGS 2002a and b; CGS 2007; CDMG 1994; CDMG 2003; Fiore et al. 2007; Nicholson 1990; SCEDC 2008; Smith 1992; USGS 2006; USGS 2008), informational websites, and analytical and database software (Blake 2000a and b) in order to gather data on the location, recency, and type of faulting in the project area. Type A and B faults within 70 miles (112 kilometers) of the site under consideration are listed in **Geology and Paleontology Table 3**. Type A faults have slip-rates of >5 mm per year and are capable of producing an earthquake of magnitude 7.0 or greater. Type B faults have slip-rates of 2 to 5 mm per year and are capable of producing an earthquake of magnitude 6.5 to 7.0. The fault type, potential magnitude, and distance from the proposed site are summarized in **Geology and Paleontology Table 3**. Type C and otherwise undifferentiated faults that are more than 20 miles from the proposed site are not discussed here because they are not likely to produce an earthquake of sufficient magnitude that could affect the project.

Geology and Paleontology Table 3
Active Faults in the Proposed Project Area

Fault Name	Distance From Site (miles)	Maximum Earthquake Magnitude (Mw)	Estimated Peak Site Acceleration (g)	Movement and Strike	Slip Rate mm/yr	Fault Type
San Juan	34.9	7.1	0.107	Right-Lateral Strike Slip (Northwest)	1.0	B
Big Pine	41.3	6.9	0.085	Left-Lateral Strike Slip (North)	0.8	B
Garlock (West)	43.9	7.3	0.100	Left-Lateral Strike Slip (North)	6.0	B
San Gabriel	51.5	7.2	0.084	Right-Lateral Strike Slip (Northwest)	1.0	B
San Luis Range (South Margin)	53.0	7.2	0.100	Reverse (North)	0.2	B
North Channel Slope	53.7	7.4	0.110	Reverse (West)	2.0	B
Great Valley 14	54.7	6.4	0.064	Reverse (North) Blind Thrust	1.5	B
Santa Ynez (East)	56.0	7.1	0.074	Left-Lateral Strike Slip (North)	2.0	B
M.Ridge – Arroyo Parida - Santa Ana	56.5	7.2	0.095	Reverse (West)	0.4	B
Santa Ynez (West)	57.40	7.1	0.073	Left-Lateral Strike Slip (North)	2.0	B
San Cayetano	58.4	7.0	0.083	Reverse (West)	6.0	B
San Andreas - Parkfield	59.2	6.5	0.052	Right-Lateral Strike Slip (Northwest)	34.0	A
Red Mountain	61.6	7.0	0.080	Reverse (West)	2.0	B
Los Alamos – West Baseline	61.8	6.9	0.075	Reverse (West)	0.7	B
Los Osos	62.1	7.0	0.079	Reverse (Southwest)	0.5	B
San Andreas – Whole	21.1	8.0	0.253	Right-Lateral Strike Slip (Northwest)	34.0	A
San Andreas – Carrizo, Ft. Tejon Rupture	21.1	7.8	0.228	Right-Lateral Strike Slip (Northwest)	34.0	A
White Wolf	23.5	7.3	0.196	Reverse, Left-Lateral, Oblique (West)	2.0	B
San Andreas – Cholame	27.2	7.3	0.144	Right-Lateral Strike Slip (Northwest)	34.0	A
Pleito Thrust	27.3	7.0	0.150	Reverse (West)	2.0	B

Twenty Type A and B faults and fault segments were identified within 62 miles (100 kilometers) of the proposed site (**Geology and Paleontology Figure 4)**. All three of the Type A faults are segments of the San Andreas Fault System. The closest of these is the Carrizo segment located 21 miles to the west and southwest. The San Andreas Fault is the dominant active tectonic feature of the Coast Ranges and represents the boundary of the North American and Pacific plates. Right-lateral strike-slip motion occurs along the structural zone at an average rate of 51.1 ± 2.5 millimeters per year. The Carrizo segment is capable of producing a moment magnitude earthquake of 7.8 (7.8M). Surface rupture occurred along a 225 mile stretch of the San Andreas fault, which included the Carrizo segment, Cholame segment to the northwest, and Mojave segment to the southeast, during the Magnitude 7.9 Fort Tejon Earthquake in 1857 (SCEDC 2008). The southern end of the Cholame segment is located approximately 27 miles northwest of the proposed site, and has been assigned a maximum moment magnitude of 7.3.

Faulting and uplift that resulted in the formation of the Elk Hills anticline began in the Miocene and continued through present time (Fiore et al. 2007; Nicholson 1990). Although historic surface rupture has not been observed along faults in the Elk Hills, Quaternary age, movement is well documented. Two major groups of Quaternary faults are mapped in the Elk Hills area (CDMG 1994; Dibblee 2005a; Fiore et al. 2007; Nicholson 1990). At least four northeast-striking faults are present in the eastern Elk Hills, the nearest of which is located approximately 500 feet southeast of the south end of the proposed carbon dioxide pipeline options. Eleven faults in the western Elk Hills are oriented east to northeast and northwest, and are located at least 6 miles west of the proposed HECA plant site (CDMG 1994; Dibblee 2005b).

Preliminary estimates of ground motion based on probabilistic seismic hazard analyses have been calculated for the project site using the USGS Earthquake Hazards application called the U.S. Seismic “DesignMaps” Web Application (**Geology and Paleontology Table 4**). This application produces seismic hazard curves, uniform hazard response spectra, and seismic design values. The values provided by this application are based upon data from the 2008 USGS National Seismic Hazard Mapping Project. These design parameters are for use with the 2012 International Building Code, the 2010 ASCE-7 Standard, the 2009 NEHRP Provisions, and their respective predecessors.

These parameters are project-specific and, based on HECA’s location, were calculated using latitude and longitude inputs of 35.339 degrees north and 119.393 degrees west, respectively. Other inputs for this application are the site “type” which is based on the underlying geologic materials and the “Structure Risk Category”. The assumed site class for HECA is “D”, which is applicable to stiff soil. These parameters can be updated as appropriate following the results presented in a project-specific geotechnical investigation report performed for the site. The assumed “Structure Risk Category” is “III”, which is based on its inherent risk to people and the need for the structure to function following a damaging event. Risk categories range from I (non essential) to IV (critical). Examples of risk category I include agriculture facilities, minor storage facilities, etc., while examples of category IV include fire stations, hospitals, nuclear power facilities, etc.

The ground acceleration values presented are typical for the area. Other developments in the adjacent area would also be designed to accommodate strong seismic shaking. The potential for and mitigation of the effects of strong seismic shaking during an earthquake should be addressed in a project-specific geotechnical report, per CBC 2010 requirements, and proposed **FACILITY DESIGN GEN-1**, **GEN-5** and **CIVIL-1**. Compliance with these conditions of certification would ensure the project is built to current seismic standards and potential impacts would be mitigated to less than significant levels in accordance with current standards of engineering practice.

Geology and Paleontology Table 4
Planning Level 2010 CBC Seismic Design Parameters Maximum Considered Earthquake, ASCE 7 Standard

Parameter	Value
Assumed Site Class	D
Structure Risk Category	III - Substantial
SS – Mapped Spectral Acceleration, Short (0.2 Second) Period	1.116 g
S1 – Mapped Spectral Acceleration, Long (1.0 Second) Period	0.448 g
Fa – Site Coefficient, Short (0.2 Second) Period	1.054
Fv – Site Coefficient, Long (1.0 Second) Period	1.552
SDS – Design Spectral Response Acceleration, Short (0.2 Second) Period	0.784 g
SD1 – Design Spectral Response Acceleration, Long (1.0 Second) Period	0.463 g
SMS – Spectral Response Acceleration, Short (0.2 Second) Period	1.176 g
SM1 – Spectral Response Acceleration, Long (1.0 Second) Period	0.695 g

ASCE = American Society of Civil Engineers
Values from USGS 2010b

Carbon dioxide produced during operation of the proposed HECA facility would be captured, piped southward to the actively producing Elk Hills oil and gas fields, and injected into porous rocks several thousand feet underground. These proposed operations would sequester the carbon dioxide underground, preventing its release into the atmosphere, and enhance oil recovery (Terralog 2008). The proposed volume of carbon dioxide injected would be less than the quantities of water, steam and gas currently injected to increase oil production in the Elk Hills. Fluid injection is known to have increased levels of small-scale seismicity at other locations in the United States, although none has been documented as a result of water, steam and gas injection in the Elk Hills oil and gas fields. Any additional seismic event resulting from proposed carbon dioxide injection is not expected to exceed a magnitude 4 earthquake (Terralog 2008). The maximum anticipated peak acceleration the proposed HECA site would experience is on the order of 0.01 g, which is more than an order of magnitude less intense than site accelerations associated with maximum credible earthquakes on faults listed in **Geology and Paleontology Table 3**. Since the proposed HECA plant would be designed to withstand much higher levels of ground shaking associated with earthquakes on active faults within 30 miles of the site, the potential for minor levels of increased seismicity associated with carbon dioxide injection poses no additional geologic hazard to the plant.

Local residences could be subject to an increase in frequency of seismic shaking related to fluid injection. The intensity of induced seismicity at local residences is likely to be very low and not sufficiently strong to cause damage. Therefore impacts to local residences due to induced seismicity are considered to be less than significant.

The potential for strong ground shaking would be addressed in proposed Facility Design Condition of Certification **GEN-1**. Proper design in accordance with this condition, as well as with requirements presented in a site-specific, design-level geotechnical report, should adequately mitigate seismic hazards to the current standards of practice.

Liquefaction

Liquefaction is a phenomenon whereby loose, saturated, granular soils lose their inherent shear strength because of excess pore water pressure build-up, such as that generated during repeated cyclic loading from an earthquake. A low relative density of the granular materials, shallow groundwater table, long duration, and high acceleration of seismic shaking are some of the factors favorable to cause liquefaction.

The presence of predominantly cohesive or fine-grained materials and/or absence of saturated conditions can preclude liquefaction. Liquefaction hazards are usually manifested in the form of buoyancy forces during liquefaction, increase in lateral earth pressures due to liquefaction, horizontal and vertical movements resulting from lateral spreading, and post-earthquake settlement of the liquefied materials.

Four of the parameters used to assess the potential for liquefaction are soil density, soil texture, depth to ground water, and the peak horizontal ground acceleration estimated for the site. Historic depths to ground water at the proposed project site range from approximately 19 feet (CDWR 2004) to 35 feet below the existing ground surface, although ground water was not encountered in hollow-stem auger borings advanced to a maximum depth of 101.5 feet. SPT testing conducted during the site geotechnical investigation indicates that soils below approximately 15 feet are generally too dense to be subject to liquefaction (HEI 2008c). However, ground water levels should be confirmed, and the liquefaction potential on the proposed HECA site should be addressed in a project-specific geotechnical report, per CBC 2010 requirements and proposed **FACILITY DESIGN GEN-1**, **GEN-5** and **CIVIL-1**.

Lateral Spreading

Lateral spreading of the ground surface can occur within liquefiable beds during seismic events. Lateral spreading generally requires an abrupt change in slope—that is, a nearby steep hillside or deeply eroded stream bank, etc.—but can also occur on gentle slopes. Other factors such as distance from the epicenter, magnitude of the seismic event, and thickness and depth of liquefiable layers also affect the amount of lateral spreading. The HECA site is underlain by predominantly unsaturated, cohesive, fine-grained materials that are not typically associated with liquefaction and there is no nearby steep hillside that would accommodate lateral spreading. Staff recommends that the liquefaction potential of underlying beds beneath the proposed HECA site be addressed in a project-specific geotechnical report, per CBC 2010 requirements and proposed **FACILITY DESIGN GEN-1, GEN-5** and **CIVIL-1**.

Dynamic Compaction

Dynamic compaction of soils results when relatively unconsolidated granular materials experience vibration associated with seismic events. The vibration causes a decrease in soil volume, as the soil grains tend to rearrange into a more dense state (an increase in soil density). The decrease in volume can result in settlement of overlying structural improvements. The site specific geotechnical investigation indicates the alluvial deposits in the proposed site subsurface are generally too dense to allow significant dynamic compaction (URS 2009a). Staff recommends that the potential for, and mitigation of, the effects of dynamic compaction of proposed site native and fill soils during an earthquake be addressed in a project-specific geotechnical report, per CBC 2010 requirements and proposed **FACILITY DESIGN GEN-1**, **GEN-5** and **CIVIL-1**. Common mitigation methods would include deep foundations (driven piles; drilled shafts) for severe conditions, geogrid reinforced fill pads for moderate severity and over-excavation and replacement for areas of minimal hazard.

Hydrocompaction

Hydrocompaction (also known as hydro-collapse) is generally limited to young soils that were deposited rapidly in a saturated state, most commonly by a flashflood. The soils dry quickly, leaving an unconsolidated, low density deposit with a high percentage of voids. Foundations built on these types of compressible materials can settle excessively, particularly when landscaping irrigation dissolves the weak cementation that is preventing the immediate collapse of the soil structure. Hydrocompaction is the process of the loss of soil volume upon the application of water.

Hydrocompaction has been documented in several areas in the southern San Joaquin Valley southwest and west of Bakersfield; however, the proposed HECA project site would not be located within any of these designated areas (Kern County 2000; USGS 1984). The potential for significant consolidation due to hydrocompaction is considered remote. The proposed site area has been irrigated and cultivated extensively, which would likely have induced settlement in soils that had a potential for hydrocompaction. The proposed site specific geotechnical investigation also indicates the subsurface alluvial deposits which underlie the site would generally be too dense to experience significant hydrocompaction (URS 2009a). Staff recommends that the potential for and mitigation of the effects of hydrocompaction of site soils be addressed in a project-specific geotechnical report, per CBC 2010 requirements and proposed **FACILITY DESIGN GEN-1**, **GEN-5** and **CIVIL-1**. Typical mitigation measures would include over-excavation/replacement, mat foundations or deep foundations, depending on severity and foundation loads.

Subsidence

Subsidence of surficial and near surface soil units can result from loading of loose or soft soils by foundations, or by the extraction of fluids from the subsurface. Load-induced consolidation has been addressed by the project geotechnical investigation (HEI 2008c, Appendix P), as required by Facility Design Conditions of Certification **GEN-5** and **CIVIL-1.**

Regional ground subsidence is typically caused by petroleum or ground water withdrawal that increases the effective unit weight of the soil profile, which in turn increases the effective stress on the deeper soils. This results in consolidation or settlement of the underlying soils. Subsidence due to ground water withdrawal has occurred throughout much of the San Joaquin Valley in the decades prior to the 1970's (USGS 1984; USGS 2000). Ireland and others show the site as lying outside areas with documented subsidence, in excess of one foot, due to ground water withdrawal (USGS 1984). Petroleum and gas fields are also located in the Elk Hills adjacent to the proposed project site area and throughout the southern portion of the Great Valley Geomorphic Province (CDC, 1998). Despite the proximity of oil fields relative to the proposed site, subsidence in the area was not indicated in the Geologic Hazards and Resources section of the AFC, or in the supporting preliminary geotechnical report (HEI

2008c, Appendix P) The potential impacts related to groundwater withdrawal for project supply are addressed in the **Water Supply** section of this analysis. Staff recommends that the potential for and mitigation of the effects of subsidence of site soils be addressed in a project-specific geotechnical report, per CBC 2010 requirements and proposed **FACILITY DESIGN GEN-1**, **GEN-5** and **CIVIL-1**. Typical mitigation measures would include over-excavation/replacement, mat foundations or deep foundations, depending on severity and foundation loads.

Expansive Soils

Soil expansion occurs when clay-rich soils with an affinity for water exist in-place at a moisture content below their plastic limit. The addition of moisture from irrigation, precipitation, capillary tension, water line breaks, etc. causes the clay soils to absorb water molecules into their structure, which in turn causes an increase in the overall volume of the soil. This increase in volume can correspond to excessive movement (heave) of overlying structural improvements.

Expansion potential of soils is usually measured by plasticity index and expansive index tests. The most hazardous soils have high clay contents, and the clays have a high shrink-swell potential and a high plasticity index. Near surface soils in the proposed project vicinity consist generally of sandy lean and fat clays, with measured plasticity indices of 29 and 41, and expansion indices of 73 and 83 (HEI 2008c, Appendix P). The soils classify as moderately expansive, which could pose a hazard to facility foundations if mitigation measures are not implemented (URS 2009a).

Staff recommends that the potential for, and mitigation of, the effects of expansive soils on the proposed site be addressed in a project-specific geotechnical report, per CBC 2010 requirements and proposed **FACILITY DESIGN GEN-1**, **GEN-5** and **CIVIL-1**. Mitigation would normally be accomplished by over-excavation and replacement of the expansive soils. For deep-seated conditions, deep foundations are commonly used. Lime-treatment (chemical modification) is often used to mitigate expansive clays in pavement areas.

Landslides

Landslides occur when masses of rock, earth, or debris move down a slope, including rock falls, deep failure of slopes, and shallow debris flows. Landslides are influenced by human activity (mining and construction of buildings, railroads, and highways) and natural factors (geology, precipitation, and topography). Frequently, they accompany other natural hazards. Although landslides sometimes occur during earthquake activity, earthquakes are rarely their primary cause.

The most common cause of a landslide is an increase in the down slope gravitational stress applied to slope materials (oversteepening). This may be produced either by natural processes or human activities. Undercutting of a valley wall by stream erosion is a common way in which slopes may be naturally oversteepened. Other ways include excessive rainfall or irrigation on a cliff or slope.

The site is relatively flat and located substantial distances from steep terrain. Therefore, the site is not subject to landslide hazards.

Flooding

The proposed site and linear facilities would be located in a shaded Zone X defined as "Areas of 0.2 percent annual chance flood, areas of one percent annual chance flood with average depth of less than one foot, or with drainage area of less than one (1) square mile; areas protected by levee from one percent annual chance flood" (FEMA 2008). Further analysis of site drainage and stormwater flows is discussed in the **Soil and Surface Water** section of this analysis.

Tsunamis and Seiches

Tsunamis are large-scale seismic-sea waves caused by offshore earthquakes, submarine landslides, landslides falling into water bodies and/or volcanic activity. Seiches are waves generated within enclosed water bodies such as bays, lakes or reservoirs caused by seismic shaking, rapid tectonic uplift, basin bottom displacement and/or land sliding. The proposed power plant site is located approximately 200 miles inland from the coast. There are no water bodies located at an elevation above the project site within the project vicinity. Therefore, the site is not subject to either tsunami of seiche hazards.

The design-level geotechnical investigation required for the proposed project by the CBC 2010 and proposed **FACILITY DESIGN GEN-1**, **GEN-5** and **CIVIL-1** should provide standard engineering design recommendations for mitigation of seismic shaking, ground subsidence, expansive clay soils, liquefaction and excessive settlement due to compressible soils or dynamic compaction, as appropriate.

Construction Impacts and Mitigation

The design-level geotechnical investigation, required for the proposed project by the CBC (2010) and proposed Conditions of Certification **GEN-1**, **GEN-5** and **CIVIL-1** of the **Facility Design** section of this document, provide standard engineering design recommendations for mitigation of earthquake ground shaking, excessive settlement and expansive soils.

As noted above, no viable geologic or mineralogic resources are known to exist in the vicinity of the proposed construction site or project linears, with the exception of the Elk Hills and associated oil and gas fields. Current and future oil and gas production from these deposits would not be expected to be adversely impacted by proposed construction of the HECA plant site and project linears.

Quaternary alluvium and Pliocene to Pleistocene Tulare Formation deposits beneath the proposed site have a high sensitivity rating for paleontologic impacts. Based on the soils profile, SVP assessment criteria, and the shallow depth of potentially fossiliferous geologic units, staff considers the probability of encountering paleontological resources during construction of the proposed HECA project to be high. Quaternary alluvium near the surface is less sensitive relative to deeper and older alluvium (McLeod 2009), however, all Quaternary sediments at the project site should be considered to have a high sensitivity rating until determined otherwise by a qualified professional paleontologist. Since the upper portion of the surface has been disturbed during agricultural operations, the upper 1 to 2 feet of ground would not be likely to yield fossil remains in their natural context. Any excavation into undisturbed native ground at the surface or below disturbed material at the proposed plant site and along project linears, would be considered to have a high potential to encounter significant paleontological resources.

Mass grading operations within proposed structure footprints, that could be required for removal of expansive clays, would have the potential to disturb paleontological resources. Fossil remains could also be encountered in deep trenches excavated for utilities, and for construction of drilled shaft foundations that may be used to support heavily loaded structures. Any fossil brought to the surface by drilling operations would be badly disturbed and out of context.

Proposed Conditions of Certification **PAL-1** to **PAL-7** are designed to mitigate any paleontological resource impacts, as discussed above, to a less than significant level. Essentially, these conditions would require a worker education program in conjunction with monitoring of earthwork activities by qualified professional paleontologists (PRS). Earthwork is halted any time potential fossils are recognized by either the paleontologist or the worker. The science of paleontology is advanced by the discovery, study and curation of new fossils. These fossils can be significant if they represent a new species, verify a known species in a new location, provide museum quality specimens, or if they include structures of similar specimens that had not previously been found preserved, among other criteria. Most fossil discoveries are the result of excavations, either purposeful in known or suspected fossil localities or as the result of excavations made during earthwork for civil improvements or mineral extraction. Proper monitoring of excavations at the proposed HECA facility, in accordance with an approved Paleontological Monitoring and Mitigation Plan (proposed **PAL-3**), could result in fossil discoveries that would enhance our understanding of the prehistoric climate, geology, and geographic setting of the region for the benefit of current and future generations. When properly implemented, the conditions of certification yield a net gain to the science of paleontology, since fossils that would not otherwise have been discovered can be collected, identified, studied, and properly curated.

A PRS is retained, for the project by the applicant, to produce a monitoring and mitigation plan, conduct the worker training, and provide the monitoring, per **PAL-3** through **PAL-6**. This plan is based on anticipated conditions, typically deduced from the available regional-level geologic mapping, museum records, and a brief site reconnaissance. Geologic conditions on the scale of a single project site can differ greatly from what was anticipated. During the monitoring, the PRS may petition the Energy Commission for a change in the monitoring protocol. Most commonly, this is a request for lesser monitoring after sufficient monitoring has been performed to ascertain that there is little chance of finding significant fossils (**PAL-5**). In other cases, the PRS may propose increased monitoring due to unexpected fossil discoveries or in response to repeated out-of-compliance incidents by the earthwork contractor. At the proposed HECA site, a PRS may evaluate Quaternary alluvium exposed in new excavations, and determine a minimum depth above which the potential for encountering paleontological resources is low. The PRS may then recommend decreased monitoring in excavations above this depth.

Based upon the literature and archives search, field surveys, and compliance documentation for the proposed project, the applicant proposes monitoring and mitigation measures for construction of the proposed power plant. Energy Commission staff agrees with the applicant that the project can be designed and constructed to minimize the effects of geologic hazards at the site, during project design life, and that impacts to vertebrate, invertebrate and trace fossils encountered during construction can be mitigated to levels of less than significant.

Operation Impacts and Mitigation

The operation of HECA would not present additional risk to geological resources (none identified) or paleontological resources. Once ground disturbing activity is complete, plant operation has no real potential to further affect paleontological resources. Therefore, routine plant operation would not increase potential cumulative effects on paleontological resources. The longer the plant operates, however, the more likely it is to be affected by geological hazards, primarily earthquake-related ground shaking. For example, USGS data indicates that there is a 20 percent probability that a bedrock ground acceleration of 0.206g would be exceeded at the site in any 50-year interval (USGS 2006). This equates to a recurrence interval of about 250 years. The CBC (2010) requires that the structures be designed for a 2,500 recurrence interval event (two percent probability in 50 years) which shows a much higher bedrock ground acceleration of 0.46g. The longer the project operates, the higher the probability of both an earthquake and high ground acceleration. This situation is the same for all developments anywhere and not unique to this project at this site. The design requirements of the CBC are intended to protect occupants from building collapse during the design-level earthquake, one with only two percent probability of being exceeded in any 50-year interval. The code does not require that the structures be salvageable after such an event. Construction and operation of the plant does not increase the potential of geological hazards at the site, but the potential for earthquake-generated ground shaking at the site unavoidably increases with every year of operation.

OEHI SETTING

The Elk Hills Oil Field (EHOF) is located along the southwest edge of the San Joaquin Valley, approximately 26 miles (42 Kilometers [km]) southwest of Bakersfield in western Kern County, California. The entire EHOF is approximately 48,000 acres.

The EHOF was originally developed as part of the federal Naval Petroleum Reserves. This area is situated immediately south of, and contiguous with, the Lokern Area of Critical Environmental Concern (ACEC) a part of which (3,111 acres) is controlled by the Bureau of Land Management (BLM). Portions of this surrounding area (2,050 acres), are managed as conservation areas by the Center for Natural Lands Management (CNLM) and OEHI (formerly Plains Exploration and Production Company and Nuevo Energy Company) Habitat Management Lands (200 acres). The remainder is owned by Chevron Corporation and others. The City of Buttonwillow is located directly to the north. McKittrick Valley and portions of Buena Vista Valley with Highway 33 running NW-SE are to the west. The cities of McKittrick and Derby Acres are located along Highway 33. Approximately ten miles to the west and across the Temblor Range is the Carrizo Plain National Monument (199,030 acres).

To the south of the EHOF is the Buena Vista Valley, the majority of which is within another Naval Petroleum Reserve oil field. The City of Taft is located approximately seven-miles to the south. Mostly undeveloped areas are located along Highway 119 to the southeast of EHOF. Lands to the immediate east include Coles Levee Ecological Preserve (CLEP; 6,059 acres), Kern Water Bank Authority (19,900 acres), Tule Elk Reserve State Park and the Kern River. The California Aqueduct and the West Side Canal converge and flow along the north and eastern boundary of EHOF, as does the Kern River. The Buena Vista Lake Bed is located immediately southeast of Highway 119. Bakersfield is approximately 26 miles to the northeast. The EHOF is circumscribed by Highway 5 to the north and east, Highways 119 and 33 to the south, Highway 33 to the west and Highway 58 to the north. Elk Hills Road runs north and south and bisects the Project area.

REGIONAL SETTING

The EHOF is located in the Great Valley geomorphic province. The Great Valley Province is characterized by a large northwest trending valley bounded by the Sierra Nevada province to the east and south, the Klamath Mountains province to the north, the Cascade Range province to the northeast, and the Coast Range province to the west. The Great Valley Province is filled with thick sediments eroded from the surrounding mountain ranges.

The Great Valley province is underlain by a thick (up to 80,000 feet thick) sequence of sedimentary units (the Great Valley Sequence) which are Jurassic age or younger. The valley is an asymmetrical synclinal trough with a more gently dipping eastern limb.

The project site is located on the western side of the San Joaquin Valley. The San Joaquin Valley is filled with thick Mesozoic and Tertiary marine and non-marine sediments covered by a relatively thin veneer of Quaternary alluvial sediments (Bailey 1966). Kettleman Hills, Elk Hills, and Buena Vista Hills provide the only significant topographic relief in the San Joaquin Valley portion of the Great Valley province (Stantec 2012).

Prior to the early Eocene epoch the bulk of the province was covered by seas. As the seas withdrew, increasing terrestrial sediments were deposited from the erosion of the Sierra Nevada to the east. During the Eocene there was uplift on the margins of the province causing the seas to gradually recede. During this time the Stockton Arch (the division between the northern and southern parts of the province) was also rising. Subsidence of the valley during late Eocene time caused the seas to again inundate the province. As the valley continued to fill with sediments, the seas occupied smaller areas. By the end of the Pliocene the seas had finally withdrawn for the last time from the southwestern portion of the province, the last area to be submerged. The last large lake to occupy the Great Valley Province was Lake Corcoran, about 600,000 years ago (URS, 2008). Lake Corcoran covered much of the western part of the San Joaquin Valley. The resulting Corcoran Clay (composed of fine clays, volcanic ash, and diatomite) covers more than 5,000 square miles and forms an extensive aquaclude creating a major confined aquifer (Stantec 2012).

The EHOF is located near the south-western edge of the San Joaquin Valley, approximately 25 miles southwest of the city of Bakersfield in Kern County, California.

The EHOF is approximately 17 miles long (generally east to west) and over 7 miles wide (generally north to south). The highest elevation in the Elk Hills is 1,551 feet above mean sea level, which is between 1,000 to 1,200 feet above the floor of the San Joaquin Valley. The Tertiary (Tulare Formation) and Quaternary-aged deposits underlying the Elk Hills and nearby areas are up to 24,000 feet thick (U.S. Department of Energy [DOE], 1997).

The Tulare Formation lies at the surface of Elk Hills and consists of gravel, sand, and silt derived from erosion of the Monterey Formation exposed in the Temblor Range to the west. (Stantec 2012). Lithologically, the Tulare Formation consists of argillaceous sand and silt deposits with lenses of coarse sand and gravel. Conglomerate units do occur, but are rare overall.

OEHI SITE DESCRIPTION

The original project description provided by ManageTech (2010) identified a projected total of 550 injection and production wells. Upon additional evaluation, OEHI has increased the number of projected wells to 720 (309 injection wells and 411 production wells). OEHI has designed the Project to utilize existing wells to the maximum extent feasible. It is estimated that 570 of the 720 wells necessary for the proposed Project would utilize pre-existing well locations. The remaining 150 wells would be new installations.

Utilizing existing wells and pads would substantially reduce the amount of Project disturbances and reduce the potential air quality, biologica,l and cultural impacts that could result from Project implementation. The disturbance footprint for each new well to be installed as part of the proposed Project was calculated based on the use of the Ensign 533 and 535 drilling rigs. The Ensign 533 and 535 drill rigs have an estimated 130 feet wide by 280 feet long (sump and drill rig/pad) disturbance footprint. This equates to an approximately 36,400 square-foot or approximately 0.84 acres of disturbance per new well.

The original project description estimated approximately 550 miles of ancillary piping for operation of the CO_2 EOR component (which equated to approximately 1 mile of pipeline per well). Further analyses of well and piping requirements performed by OEHI indicate that between approximately 552-652 miles of pipeline may be necessary. The higher estimate of 652 miles was developed in consideration of surface encumbrances (e.g., topographic constraints, goal of utilizing existing pipeline ROWs to the maximum extent feasible, and avoidance of environmentally and culturally sensitive areas of concern).

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

This section considers two types of impacts. The first is the potential impacts the proposed facility could have on existing geologic, mineralogic, and paleontologic resources in the area. The second is the potential geologic hazards that could adversely impact the proper functioning of the proposed facility and create life/safety concerns.

DIRECT/INDIRECT IMPACTS AND MITIGATION

An assessment of the potential impacts to geologic, mineralogic, and paleontologic resources, and from geologic hazards is provided below. The assessment of impacts is followed by a summary of potential impacts that may occur during construction and operation of the project and provides recommended conditions of certification that would ensure potential impacts are mitigated to a level that is less than significant. The recommended mitigation measures would allow the lead agency's compliance project manager and the applicant to adopt a compliance monitoring scheme ensuring ongoing compliance with LORS applicable to geologic hazards and the protection of geologic, mineralogic, and paleontologic resources.

GEOLOGIC AND MINERALOGIC RESOURCES

The mineral resources addressed in this section pertain to those resources that are classified under the Surface Mining and Reclamation Act of 1975 (SMARA). The SMARA requires the California State Mining and Geology Board (SMGB) to adopt state policy for the reclamation of mined lands and the conservation of mineral resources. The SMARA provides a comprehensive surface mining and reclamation policy with the regulation of surface mining operations to assure that adverse environmental impacts are minimized. The SMARA also encourages the production, conservation, and protection of the state's mineral resources. The SMARA was amended in 1980 to provide for the classification of non-urban areas subject to land-use threats incompatible with mining. The classification of land within California takes place according to a priority list that was established by the SMGB in 1982, or when the SMGB is petitioned to classify a specific area. Currently, the State Geologist's SMARA classification activities are carried out under a single program for urban and nonurban areas of the state. Mineral lands are mapped using the California Mineral Land Classification System. Priority is given to areas where future mineral resource extraction could be precluded by incompatible land use or to mineral resources likely to be mined during the 50-year period following their classification. Detailed mineral land classification and designation reports provided by the SMGB are on file at the county.

Pursuant to SMARA, the California Geological Survey within the State of California, Department of Conservation designates Mineral Resource Zones (MRZ) in portions of the state that are considered to have potentially significant mineral deposits. "Mineral resources" are those economical mineral concentrations in such form and amount that the economic extraction of a commodity from the concentrations is currently potentially feasible. A "reserve" is that part of the resource base that could be economically extracted or produced within the foreseeable future. For any given mineral resource, an area may be classified as follows:

- MRZ-1: Areas where the available geologic information indicates that no significant mineral deposits are present, or where it is judged that no significant likelihood exists for their presence.
- MRZ-2a: Areas where the available geologic information indicates that significant mineral deposits are present.
- MRZ-2b: Areas where the available geologic information indicates that there is likelihood for the presence of significant mineral deposits.

- MRZ-3a: Areas where the available geologic information indicates that mineral deposits exist, the significance of which cannot be evaluated from existing data.
- MRZ-3b: Areas where the available geologic information indicates that mineral deposits are likely to exist, the significance of which cannot be determined from available data.
- MRZ-4: Areas where available geologic information is inadequate for assignment into any other MRZ, or where there is not enough information available to determine the presence or absence of mineral deposits.

The MRZ classifications are applied based on available geologic information and upon geologic appraisal of the mineral resource potential of the land, including geologic mapping and other information on surface exposures, drilling records, and mine data; and on socioeconomic factors such as market conditions and urban development patterns. Within the Bakersfield production/ consumption region (including the EHOF), only MRZ-1 through MRZ-3 are used.

The major resources of sand and gravel within the county are in the stream deposits along the eastern side of the San Joaquin Valley and in the Sierra Nevada foothills, and in alluvial fan deposits along the north flank of the San Emidio and Tehachapi Mountains. Most of the recent alluvium in the San Joaquin Valley floor is composed of sand used as a source of road base material.

The Buttonwillow Compaction Products Mine is located northwest of the Project Site and is designated MRZ-2 for base and fill material. The proposed Project Site is state-designated as MRZ-3 on the 2009 production/consumption region for portland cement concrete grade aggregate (sand and gravel) resources; therefore, it is located within an area containing mineral deposits the significance of which cannot be evaluated from available data. The proposed Project Site is located within a currently active oil field and does not contain sand and gravel resources that are currently being extracted. In addition, there was no evidence of past or current sand and gravel extraction occurring within the proposed Project Site.

Gold has been the most important metallic mineral mined in Kern County, in terms of the total dollar value. It has been recovered by both placer and lode mining mainly in the Sierra Nevada and desert regions. Principal placer deposits are in the Rand District, El Paso Mountains and along the Kern River. About 1,500 gold claims have been registered in Kern County with approximately 280 of those claims activated as either lode or placer mines. The total amount of gold that was extracted from the Kern County sites is not available, as records were not kept during the more active lode mining activities prior to 1900.There is no evidence of gold or other precious metal mineral resources located within the proposed OEHI site.

Kern County produces more oil than any other county in California, and is one of the nation's leading petroleum-producing counties. Oil is found in 15 of the 58 counties in California. Mineral and petroleum resources are essential to the county's economy. As new recovery technologies are introduced, petroleum extraction should continue to be of economic importance to the county. As long as new urbanization is restricted in areas having important mineral and petroleum resources, the future production of these resources remains promising.

The oil industry dates backs to the nineteenth century. The first developed oil field in the county was at the McKittrick Field in 1898. Development was facilitated by existence of the Southern Pacific Railroad from Bakersfield to McKittrick Field. The Kern River Oil Field was established in 1899 and by 1903, 796 wells produced almost 17 million barrels of oil from the Kern River Field. In 1911, the EHOF was discovered, and in 2008 the EHOF was ranked fifth in recovery of California's Giant oil fields. In the mid-1930's, several valley oil fields were found in large anticlines in Miocene oil sands beneath the valley floor. These discoveries were made following the advent of the reflection seismograph. Discoveries included the Ten Section, Greeley, Rio Bravo North, Coles Levee, South Coles Levee, and Strand oil fields.

Kern County is located within District #4 of the State Department of Conservation, Division of Oil, Gas, and Geothermal Resources. With the exception of about one percent, which comes from Tulare, Kings and San Luis Obispo Counties, all resources produced in District #4 listed in state publications are from Kern County. The proposed Project Site is located within the EHOF, an active operating oil field.

As discussed above, the OEHI component is limited to utilizing CO_2 enhanced oil recovery within an existing oil and gas field. It does not include any component that would contribute to a substantial cumulative impact to mineral resources. Therefore, implementation of the proposed project would result in a less than significant cumulative mineral resources impact.

PALEONTOLOGIC RESOURCES

The OEHI site is known to contain paleontological resources. In 2009, PaleoResource Consultants conducted a field survey as part of an assessment of the potential adverse impacts on scientifically significant resources. During the field survey for prospective fossil localities, many previously unrecorded sites were found on the western half of the EHOF. Fossils at these localities included vertebrate fossil bone fragments, invertebrate shells, and fossilized wood. Numerous paleosols (fossil soils) containing ichnofossils (root and burrow casts and molds) were also discovered.

The paleontological sensitivity of a stratigraphic unit reflects: (1) its potential paleontological productivity, and (2) the scientific significance of the fossils it has produced." URS (2009) continues, "The potential paleontological productivity of a stratigraphic unit exposed in a project area is based on the abundance/densities of fossil specimens and/or previously recorded fossil sites in exposures of the unit in and near a project site. The underlying assumption of this assessment method is that exposures of a stratigraphic unit in a project site are most likely to yield fossil remains both in quantity and density similar to those previously recorded from that stratigraphic unit in and near the project site." URS (2009) further states, "All identifiable land mammal fossils are considered scientifically important because of their potential use in providing relative age determinations and paleo-environmental reconstructions for the sediments in which they occur. Moreover, vertebrate remains are comparatively rare in the fossil record. Although fossil plants are usually considered of lesser importance because they are less helpful in age determination, they are actually more sensitive indications of their environment (Miller et al. 1971) and as sedentary organisms, are more valuable than mobile animals for paleo-environmental reconstructions. For marine sediments, invertebrate and marine algal fossils, including microfossils, are scientifically important for the same reasons that land mammal and/or land plant fossils are valuable in terrestrial deposits. The value or importance of different fossil groups varies depending on the age and depositional environment of the stratigraphic unit that contains the fossils".

Tulare Formation

There are a number of previously recorded fossil sites in the Tulare Formation in the Elk Hills as well as neighboring areas. Several fossil localities described by Woodring et al (1932) are present in the Elk Hills, and include specimens of camel, horse, rabbit, wood rat, cotton rat, silicified wood, and freshwater invertebrates. According to URS (2009), "Based upon these fossil localities, Woodring et al (1932) stated, 'the Elk Hills offer a promising field for collecting vertebrate fossils, which would fill a gap in the succession of vertebrate faunas on the Pacific Coast.' Maher et al (1975) indicated that 'scattered fish remains,' mollusk fragments, reworked foraminifers, ostracodes, pelecypods, and small gastropods have been identified from wells in the Elk Hills".

As previously mentioned, PaleoResource Consultants discovered several previously unreported fossil localities within the Tulare Formation. Tulare formation fossils identified by PaleoResource Consultants included; vertebrate fossil bones, bone fragments, invertebrate shells, and fossilized wood. Numerous paleosols (fossil soils) containing ichnofossils (root and burrow casts and molds) were also identified (PaleoResource, 2008).

Quaternary Alluvium

Research by the applicant's consultant determined that no fossil localities have been reported from Quaternary alluvium in the vicinity of the EHOF (URS 2009). However, they stated that significant vertebrate fossils have been reported from Holocene and Pleistocene sediments in several areas within Kern County.The occurrence of large and small mammals are well documented from these and older subsurface deposits and with further observation of earth-moving activities and prospecting for fossils, more specimens could be unearthed. Since fossil vertebrates have been previously reported from Quaternary alluvium within Kern County, the onsite Quaternary alluvium is also judged to have a high sensitivity.

Summary

According to PaleoResource Consultants,(PaleoResource 2008), due to the numerous previously unidentified fossil localities in and around the vicinity of the Elk Hills, "there is a high probability of scientifically significant paleontological resources being unearthed during future ground disturbing activities".

Overall, staff considers the probability that paleontological resources would be encountered during site construction activities to be high. The potential for exposure of paleontological resources would increase with depth and volume of proposed construction excavations. This assessment is based on SVP criteria and the confidential paleontological report appended to the AFC (HEI 2008c). Recommended mitigation measures **OEHI PAL-1** to **OEHI PAL-7** are designed to mitigate paleontological resource impacts, as discussed above, to less than significant levels. These conditions essentially require a worker education program in conjunction with the monitoring of earthwork activities by a qualified professional paleontological resources specialist (PRS).

The recommended mitigation measures allow the lead agency's compliance project manager (CPM) and the applicant to adopt a compliance monitoring scheme ensuring compliance with LORS applicable to geologic hazards and the protection of geologic, mineralogic, and paleontologic resources.

All applicable recommended mitigation measures (**OEHI GEO-1**, **GEN-1**, **GEN-5**, **CIVIL-1**, and **OEHI PAL-1** to **OEHI PAL-7**) allow the lead agency's CPM and the applicant to adopt monitoring schemes to ensure compliance with all LORS applicable to geologic hazards and the protection of geologic, mineralogic, and paleontologic resources.

GEOLOGICAL HAZARDS

The AFC (HEI 2008c) provides documentation of potential geologic hazards at the proposed site, including site-specific subsurface information generated by a preliminary geotechnical investigation (HEI 2008c, Appendix P). Review of the AFC, coupled with staff's independent research, indicates that the potential for geologic hazards to impact the proposed plant site during its practical design life would be low if recommendations for mitigation of seismic shaking and expansive soils are adopted and followed. Geologic hazards related to seismic shaking and adverse soil conditions are addressed in a project geotechnical report per CBC 2010 requirements (HEI 2008c, Appendix P).

Staff's independent research included the review of available geologic maps, reports, and related data of the proposed OEHI site. Geological information was available from the California Geological Survey (CGS), California Division of Mines and Geology (CDMG,), the U.S. Geological Survey (USGS), the American Geophysical Union, the Geological Society of America, and other organizations. Staff's analysis of this information is provided below.

Faulting and Seismicity

Energy Commission staff reviewed numerous CGS, USGS, and other publications, (CGS 2002a and b; CGS 2007; CDMG 1994; CDMG 2003; Fiore et al. 2007; Nicholson 1990; SCEDC 2008; Smith 1992; USGS 2006; USGS 2008), informational websites, and analytical and database software (Blake 2000a and b) in order to gather data on the location, recency, and type of faulting in the project area. Numerous faults are located within the project vicinity. The fault with the highest probability of affecting the site is the San Andreas fault located approximately 25 miles southwest of the site.

Preliminary estimates of ground motion based on probabilistic seismic hazard analyses have been calculated for the project site using the USGS Earthquake Hazards application called the U.S. Seismic "DesignMaps" Web Application (**Geology and Paleontology OEHI Table 3**). This application produces seismic hazard curves, uniform hazard response spectra, and seismic design values. The values provided by this application are based upon data from the 2008 USGS National Seismic Hazard Mapping Project. These design parameters are for use with the 2012 International

Building Code, the 2010 ASCE-7 Standard, the 2009 NEHRP Provisions, and their respective predecessors.

These parameters are project-specific and, based on OEHI's's location, were calculated using latitude and longitude inputs of 35.276 degrees north and 119.382 degrees west, respectively. Other inputs for this application are the site "type" which is based on the underlying geologic materials and the "Structure Risk Category". The assumed site class for OEHI is "D", which is applicable to stiff soil. These parameters can be updated as appropriate following the results presented in a project-specific geotechnical investigation report performed for the site. The assumed "Structure Risk Category" is "III", which is based on its inherent risk to people and the need for the structure to function following a damaging event. Risk categories range from I (non essential) to IV (critical). Examples of risk category I include agriculture facilities, minor storage facilities, etc., while examples of category IV include fire stations, hospitals, nuclear power facilities, etc.

The ground acceleration values presented are typical for the area. Other developments in the adjacent area would also be designed to accommodate strong seismic shaking. The potential for and mitigation of the effects of strong seismic shaking during an earthquake should be addressed in a project-specific geotechnical report, per CBC 2010 requirements, and proposed **Facility Design** recommended mitigation measures **GEN-1**, **GEN-5** and **CIVIL-1**. Compliance with these recommended mitigation measures would ensure the OEHI component is built to current seismic standards and potential impacts would be mitigated to less than significant levels in accordance with current standards of engineering practice.

Geology and Paleontology OEHI Table 3
Planning Level 2010 CBC Seismic Design Parameters Maximum Considered Earthquake, ASCE 7 Standard

Parameter	Value
Assumed Site Class	D
Structure Risk Category	III - Substantial
SS – Mapped Spectral Acceleration, Short (0.2 Second) Period	1.202 g
S1 – Mapped Spectral Acceleration, Long (1.0 Second) Period	0.485 g
Fa – Site Coefficient, Short (0.2 Second) Period	1.019
Fv – Site Coefficient, Long (1.0 Second) Period	1.515
SDS – Design Spectral Response Acceleration, Short (0.2 Second) Period	0.817 g
SD1 – Design Spectral Response Acceleration, Long (1.0 Second) Period	0.490 g
SMS – Spectral Response Acceleration, Short (0.2 Second) Period	1.225g
SM1 – Spectral Response Acceleration, Long (1.0 Second) Period	0.735 g

ASCE = American Society of Civil Engineers
Values from USGS 2010b

Carbon dioxide produced during operation of the proposed OEHI plant would be captured, piped southward to the actively producing Elk Hills oil and gas fields, and injected into porous rocks several thousand feet underground. These proposed operations would sequester the carbon dioxide underground, preventing its release into the atmosphere, and enhance oil recovery (Terralog 2008). The proposed volume of carbon dioxide injection would be less than the quantities of water, steam and gas currently injected to increase oil production in the Elk Hills. Fluid injection is known to have increased levels of small-scale seismicity at other locations in the United States, although none has been documented as a result of water, steam and gas injection in the Elk Hills oil and gas fields. Any additional seismic event resulting from proposed carbon dioxide injection is not expected to exceed a magnitude 4 earthquake (Terralog 2008). The maximum anticipated peak acceleration the proposed OEHI site would experience is on the order of 0.01 g, which is more than an order of magnitude less intense than site accelerations associated with maximum considered earthquake listed on **Geology and Paleontology OEHI Table 3**. Since the proposed OEHI plant would be designed to withstand much higher levels of ground shaking associated with earthquakes on active faults within 30 miles of the site, the potential for minor levels of increased seismicity associated with carbon dioxide injection poses no additional geologic hazard.

The potential for strong ground shaking would be addressed in proposed Facility Design recommended mitigation measure **GEN-1**. Proper design in accordance with this condition, as well as with requirements presented in a site-specific, design-level geotechnical report, should adequately mitigate seismic hazards to the current standards of practice.

Liquefaction

Liquefaction is not a significant concern within the OEHI site as it is underlain by hard mudstone and discontinuous beds or lenses of boulders, cobbles, gravels and coarse sands. Liquefaction is also not considered problematic where the depth to groundwater is greater than 50 feet. Studies done at the nearby Elk Hills Power Plant indicated the depth to groundwater at that location is in excess of 1,000 feet (CEC 2000).

Based on the above, the groundwater depth in the vicinity of the OEHI site exceeds 100 feet and may be as deep as 1,000 feet. The geology, soil types, and the average groundwater level present in the OEHI site indicate that the potential for liquefaction is very low. However, ground water levels should be confirmed, and the liquefaction potential on the proposed OEHI site should be addressed in a project-specific geotechnical report, per CBC 2010 requirements and proposed **Facility Design** recommended mitigation measures **GEN-1**, **GEN-5** and **CIVIL-1**.

Lateral Spreading

The OEHI site is underlain by predominantly unsaturated, coarse-grained materials that are not typically associated with liquefaction. However, ground water levels should be confirmed and the liquefaction potential of underlying beds beneath the proposed OEHI site should be addressed in a project-specific geotechnical report, per CBC 2010 requirements and proposed **Facility Design** recommended mitigation measures **GEN-1, GEN-5** and **CIVIL-1**.

Dynamic Compaction

The site is underlain by coarse alluvium and consolidated sedimentary deposits. These materials are not susceptible to significant dynamic compaction. The potential for, and mitigation of, the effects of dynamic compaction of proposed site native and fill soils during an earthquake should be addressed in a project-specific geotechnical report, per CBC 2010 requirements and proposed **Facility Design** recommended mitigation measures **GEN-1**, **GEN-5** and **CIVIL-1**. Common mitigation methods would include deep foundations (driven piles; drilled shafts) for severe conditions, geogrid reinforced fill pads for moderate severity and over-excavation and replacement for areas of minimal hazard.

Hydrocompaction

Hydrocompaction has been documented in several areas in the southern San Joaquin Valley southwest and west of Bakersfield; however, the proposed OEHI project site would not be located within any of these designated areas (Kern County 2000; USGS 1984). The potential for significant consolidation due to hydrocompaction is considered remote. The potential for and mitigation of the effects of hydrocompaction of site soils should be addressed in a project-specific geotechnical report, per CBC 2010 requirements and proposed **Facility Design** recommended mitigation measures **GEN-1**, **GEN-5** and **CIVIL-1**.

Subsidence

The project site is located outside of areas with documented subsidence in excess of one foot due to ground water withdrawal (USGS 1984). The OEHI site is located within the Elk Hills Oil Field (EHOF). By the end of 2006, approximately 1.3 billion drums of oil had been extracted from the EHOF (Stantec 2012). Despite the proximity of active oil extraction surrounding the proposed site, subsidence in the area was not indicated in the Geologic Hazards and Resources section of the AFC, in the supporting preliminary geotechnical report (HEI 2008c, Appendix P) or in the Supplemental Environmental Information (Stantec 2012).

The project would not increase ground water withdrawal and, consequently, would not cause subsidence due to ground water pumping. The potential for, and mitigation of, the effects of subsidence of site soils should be addressed in a project-specific geotechnical report, per CBC 2010 requirements and proposed **Facility Design** recommended mitigation measures **GEN-1**, **GEN-5** and **CIVIL-1**. Typical mitigation measures would include over-excavation/replacement, mat foundations or deep foundations, depending on severity and foundation loads.

Expansive Soils

Expansion potential of soils is usually measured by plasticity index and expansive index tests. The most hazardous soils have high clay contents, and the clays have a high shrink-swell potential and a high plasticity index**.** Because the Project Site is predominantly composed of sandy loam with very little to no fine-grained soil, there is a low probability of impact due to shrink-swell soil behavior.

The potential for and mitigation of the effects of expansive soils on the proposed site should be addressed in a project-specific geotechnical report, per CBC 2010 requirements and **Facility Design** recommended mitigation measures **GEN-1**, **GEN-5** and **CIVIL-1**.

Landslides

The OEHI site has several areas of moderate to relatively steep slopes. By disturbing the land and removing vegetation, construction activities can destabilize soils and slopes and increase the potential for landslides. In addition, roads can concentrate water in the adjacent land, thereby decreasing the stability of soils in these areas. The OEHI site is not located within a State of California Seismic Hazard Zone for landslides, which would require an evaluation of the potential for seismically induced landslides. The dense, relatively hard soils in the portion of the Project Site where operating equipment and pipelines would be placed generally supports a very low potential for land sliding or other forms of natural slope instability.

The potential for and mitigation of the effects of landslides on the proposed site should be addressed in a project-specific geotechnical report, per CBC 2010 requirements and **Facility Design** recommended mitigation measures **GEN-1**, **GEN-5** and **CIVIL-1**.

Flooding

The OEHI site is characterized as mountainous terrain with slopes averaging 30 percent or greater within the EHOF. The topography slopes from southwest to northeast towards the California Aqueduct. The elevation of the project area ranges from 1,500 to 300 feet above mean sea level (at the Aqueduct).

The FEMA Insurance Rate Maps (FIRMs) for the proposed Project Site are included in Community Panel Numbers 060075 C2200E, C2225E, C2625E, and C2650E for Kern County Unincorporated Areas. The proposed Project does not fall in a FEMA designated flood zone.

The project area is located within an unnamed basin where several ephemeral washes flow across alluvial sediments and terminate at various points north of the EHOF. Per the Occidental of Elk Hills Construction General Permit Compliance Plan (Compliance Plan), this area has no common water conveyance connections that can be defined between various channels. Two constructed structures that cross over/under the California aqueduct are located north of Section 23 and at the northern extent of the basin near Highway 58 west of the Lokern Road junction. These washes terminate in fields east of the aqueduct and do not flow into jurisdictional waters. Furthermore, the Compliance Plan finds that the ephemeral washes are non-jurisdictional according to the analysis method provided by the U.S. EPA and the U.S. Army Corps of Engineers.

The potential for and mitigation of the effects of flooding on the proposed site should be addressed in a project-specific geotechnical report, per CBC 2010 requirements and **Facility Design** recommended mitigation measures **GEN-1**, **GEN-5** and **CIVIL-1**.

Tsunamis and Seiches

The OEHI site is located approximately 200 miles inland from the coast. There are no water bodies located at an elevation above the project site within the project vicinity. Therefore, the site is not subject to either tsunami of seiche hazards.

The design-level geotechnical investigation required for the proposed project by the CBC 2010 and **Facility Design** recommended mitigation measures **GEN-1**, **GEN-5** and

CIVIL-1 should provide standard engineering design recommendations for mitigation of seismic shaking, liquefaction, lateral spreading, hydrocompaction, expansive soils and excessive settlement due to compressible soils or dynamic compaction, as appropriate.

Construction Impacts and Mitigation

The design-level geotechnical investigation, required for the proposed project by the CBC 2010 and recommended mitigation measures **GEN-1**, **GEN-5** and **CIVIL-1** of the **Facility Design** section of this document provide standard engineering design recommendations for mitigation of earthquake ground shaking, excessive settlement and expansive soils.

As noted above, no viable geologic or mineralogic resources are known to exist in the vicinity of the proposed construction site or project linears, with the exception of the Elk Hills and associated oil and gas fields. Current and future oil and gas production from these deposits would not be expected to be adversely impacted by proposed construction of the OEHI facility and project linears.

Quaternary alluvium and Pliocene to Pleistocene Tulare Formation deposits beneath the proposed site have a high sensitivity rating for paleontologic impacts. Based on the soils profile, SVP assessment criteria, and the shallow depth of potentially fossiliferous geologic units, staff considers the probability of encountering paleontological resources during construction of the proposed OEHI component to be high. Quaternary alluvium near the surface is less sensitive relative to deeper and older alluvium (McLeod 2009). However, all Quaternary sediments at the OEHI site should be considered to have a high sensitivity rating until determined otherwise by a qualified professional paleontologist. Any excavation into undisturbed native ground at the surface or below disturbed material at the proposed OEHI site and along project linears, would be considered to have a high potential to encounter significant paleontological resources.

Grading operations within proposed structure footprints, that could be required for foundation construction, would have the potential to disturb paleontological resources. Fossil remains could also be encountered in deep trenches excavated for utilities.

Recommended mitigation measures **OEHI PAL-1** to **OEHI PAL-7** are designed to mitigate any paleontological resource impacts, as discussed above, to a less than significant level. Essentially, these conditions would require a worker education program in conjunction with monitoring of earthwork activities by qualified professional paleontologists (PRS). Earthwork is halted any time potential fossils are recognized by either the paleontologist or the worker. The science of paleontology is advanced by the discovery, study and curation of new fossils. These fossils can be significant if they represent a new species, verify a known species in a new location, provide museum quality specimens, and/or if they include structures of similar specimens that had not previously been found preserved, among other criteria. Most fossil discoveries are the result of excavations, either purposeful in known or suspected fossil localities or as the result of excavations made during earthwork for civil improvements or mineral extraction. Proper monitoring of excavations at the proposed OEHI facility, in accordance with an approved Paleontological Monitoring and Mitigation Plan (proposed **OEHI PAL-3**), could result in fossil discoveries that would enhance our understanding of the prehistoric climate, geology, and geographic setting of the region for the benefit of current and future generations. When properly implemented, the mitigation measures would yield a net gain to the science of paleontology since fossils that would not otherwise have been discovered can be collected, identified, studied, and properly curated.

A PRS is retained for the project by OEHI, LLC, to produce a monitoring and mitigation plan, conduct the worker training, and provide the monitoring, per **OEHI PAL-3** through **OEHI PAL-6**. This plan is based on anticipated conditions, typically deduced from the available regional-level geologic mapping, museum records, and a brief site reconnaissance. Geologic conditions on the scale of a single project site can differ greatly from what was anticipated. During the monitoring, the PRS may petition the lead agency for a change in the monitoring protocol. Most commonly, this is a request for lesser monitoring after sufficient monitoring has been performed to ascertain that there is little chance of finding significant fossils (**OEHI PAL-5**). In other cases, the PRS may propose increased monitoring due to unexpected fossil discoveries or in response to repeated out-of-compliance incidents by the earthwork contractor. At the proposed OEHI facility, a PRS may evaluate Quaternary alluvium exposed in new excavations, and determine a minimum depth above which the potential for encountering paleontological resources is low. The PRS may then recommend decreased monitoring in excavations above this depth.

Based upon the literature and archives search, field surveys, and compliance documentation for the proposed project, OEHI, LLC proposes monitoring and mitigation measures for construction of the proposed OEHI. Energy Commission staff agrees that the project can be designed and constructed to minimize the effects of geologic hazards at the site, during project design life, and that impacts to vertebrate, invertebrate and trace fossils encountered during construction can be mitigated to levels of insignificance.

Operation Impacts and Mitigation

Operation of the OEHI facility should not have any adverse impact on geologic, mineralogic, or paleontologic resources. Once the facility is constructed and operating, there would be no further disturbances that could affect these resources.
Potential geologic hazards, including strong ground shaking, ground subsidence, liquefaction, settlement, hydrocompaction, or dynamic compaction can be effectively mitigated through facility design such that these potential hazards should not affect future operation of the facilities. Compliance with recommended mitigation measures **GEN-1, GEN-5 AND CIVIL-1** in the **Facility Design** section would ensure the project is constructed to current seismic building standards and potential impacts would be mitigated in accordance with current standards of engineering practice.

CUMULATIVE IMPACTS AND MITIGATION

The geographic area considered for cumulative impacts on geology and paleontology is the south portion of the San Joaquin Valley, the southern end of the Great Valley geomorphic province in central California (Norris and Webb 1990). The potential cumulative impacts are limited to those involving paleontological resources since no geological or mineralogical resources have been identified within the boundaries of the proposed project. There are no geological hazards with potential cumulative effects. No adverse cumulative impacts would be anticipated with respect to current and future oil and gas recovery from the Naval Petroleum Reserve.

The potential impacts to paleontological resources due to construction activities at the HECA site would be mitigated by proposed Conditions of Certification **PAL-1** to **PAL-7**. Construction of the project would require localized excavation and trenching. Because the project area lies predominantly within geological units with high paleontological sensitivity, the required excavation could, potentially, damage paleontological resources. Any damage could be cumulative to damage from other projects within the same geological formations. Implementation and enforcement of a properly designed Paleontological Resource Monitoring and Mitigation Plan (PRMMP; proposed **PAL-3**) at the HECA site should result in a net gain to the science of paleontology by allowing fossils that would not otherwise have been found, to be recovered, identified, studied, and preserved. Cumulative impacts from HECA, in consideration with other nearby similar projects, should therefore be either neutral (no fossils encountered) or positive (fossils encountered, preserved, and identified).

The potential impacts to paleontological resources due to construction activities on the OEHI Component would be mitigated by recommended mitigation measures **OEHI PAL-1** to **OEHI PAL-7**. Construction of the project would require localized excavation and trenching. Because the project area lies predominantly within geological units with high paleontological sensitivity, the required excavation could, potentially, damage paleontological resources. Any damage could be cumulative to damage from other projects within the same geological formations. Implementation and enforcement of a properly designed Paleontological Resource Monitoring and Mitigation Plan (PRMMP) at the OEHI site should result in a net gain to the science of paleontology by allowing fossils that would not otherwise have been found, to be recovered, identified, studied, and preserved. Cumulative impacts from OEHI, in consideration with other nearby similar projects, should therefore be either neutral (no fossils encountered) or positive (fossils encountered, preserved, and identified).

Staff believes that the potential for significant adverse cumulative impacts to the proposed project from geologic hazards, during the project’s design life, would be low, and that the potential for isolated and cumulative impacts to geologic, mineralogic, and paleontologic resources would be very low.

The proposed conditions of certification allow the CPM and the applicant to adopt a compliance monitoring scheme ensuring compliance with applicable LORS for geologic hazards and geologic, mineralogic, and paleontologic resources as they pertain to HECA.

The recommended mitigation measures allow the regulatory agencies and OEHI, LLC to adopt a compliance monitoring scheme ensuring compliance with applicable LORS for geologic hazards and geologic, mineralogic, and paleontologic resources as they pertain to the OEHI Component.

FACILITY CLOSURE

Facility closure activities would not be expected to impact geologic, paleontologic, or mineralogic resources since no such resources are known to exist at the project location. In addition, the decommissioning and closure of the project should not negatively affect geologic, mineralogic, or paleontologic resources since the majority of the ground disturbed during plant decommissioning and closure would have been already disturbed, and mitigated as required, during construction and operation of the proposed project.

DEPARTMENT OF ENERGY'S (DOE) FINDINGS REGARDING DIRECT AND INDIRECT IMPACTS OF THE NO-ACTION ALTERNATIVE

Under the No-Action Alternative, DOE would not provide financial assistance to the applicant for the HECA Project. The applicant could still elect to construct and operate its project in the absence of financial assistance from DOE, but DOE believes this is unlikely. For the purposes of analysis in the PSA/DEIS, DOE assumes the project would not be constructed under the No-Action Alternative. Accordingly, the No-Action Alternative would have no impacts associated with this resource area.

CONCLUSIONS

The proposed project would comply with applicable LORS, provided that the proposed conditions of certification are followed. The design and construction of the proposed project would have no adverse, isolated, or cumulative impacts with respect to geologic, mineralogic, and paleontologic resources. Staff proposes to ensure compliance with applicable LORS through the adoption of the proposed conditions of certification listed below.

OUTSTANDING INFORMATION REQUIRED FOR COMPLETION OF THE FSA/FEIS

Limestone would be mined and transported to the site to be used as a fluxant to reduce sulfur emissions. Currently it is unknown where the limestone is being mined, the entity that permitted the mine's operation, the capacity of the mine's resource and the estimated consumption of limestone during the project's design life.

Staff requests that this information be provided as its evaluation is necessary to complete the analysis for the completion of the FSA/FEIS.

RECOMMENDED MITIGATION MEASURES

The Energy Commission has no jurisdiction over compliance with LORS or mitigation of impacts resulting from construction and operation of the OEHI Component. Therefore, the following mitigation measures are recommendations that governing regulatory agencies (Kern County Building Department, State of California) could consider when permitting the OEHI Component.

General mitigation measures with respect to engineering geology are proposed under recommended mitigation measures **GEN-1, GEN-5**, and **CIVIL-1** in the **Facility Design** section. Proposed Geological Conditions of Certification follow.

OEHI GEO-1 The Soils Engineering Report required by Section 1803 of the 2010 CBC should specifically include laboratory test data, associated geotechnical engineering analyses, and a thorough discussion of hydrocompaction or dynamic compaction; and the presence of expansive clay soils. The report should also include recommendations for ground improvement and/or foundation systems necessary to mitigate these potential geologic hazards, if present.

The recommended mitigation measures to protect paleontological resources are listed below. It is staff's opinion that the likelihood of encountering paleontologic resources is high at the OEHI Component. Staff considers reduction in monitoring intensity could be realized at the recommendation of the project paleontologic resource specialist (PRS), following examination of sufficient, representative deep excavations that produce no significant fossil remains.

OEHI PAL-1 The project owner shall provide the lead agency's compliance project manager (CPM) with the resume and qualifications of its PRS for review and approval. If the approved PRS is replaced prior to completion of project mitigation and submittal of the Paleontological Resources Report, the project owner shall obtain the lead agency's CPM approval of the replacement PRS. The project owner shall keep resumes on file for qualified paleontological resource monitors (PRMs). If a PRM is replaced, the resume of the replacement PRM shall also be provided to the lead agency's CPM.

The PRS resume shall include the names and phone numbers of references. The resume shall also demonstrate to the satisfaction of the lead agency's CPM the appropriate education and experience to accomplish the required paleontological resource tasks.

As determined by the lead agency's CPM, the PRS shall meet the minimum qualifications for a vertebrate paleontologist as described in the SVP guidelines of 1995. The experience of the PRS shall include the following:

1. Institutional affiliations, appropriate credentials, and college degree;
2. Ability to recognize and collect fossils in the field;
3. Local geological and biostratigraphic expertise;
4. Proficiency in identifying vertebrate and invertebrate fossils; and
5. At least three years of paleontological resource mitigation and field experience in California and at least one year of experience leading paleontological resource mitigation and field activities.

The project owner shall ensure that the PRS obtains qualified paleontological resource monitors to monitor as he or she deems necessary on the project. Paleontologic resource monitors shall have the equivalent of the following qualifications:

- BS or BA degree in geology or paleontology and one year of experience monitoring in California; or
- AS or AA in geology, paleontology, or biology and four years' experience monitoring in California; or
- Enrollment in upper division classes pursuing a degree in the fields of geology or paleontology and two years of monitoring experience in California.

OEHI PAL-2 The project owner shall provide to the PRS and the lead agency's CPM, for approval, maps and drawings showing the footprint of the power plant, construction lay-down areas, and all related facilities. Maps shall identify all areas of the project where ground disturbance is anticipated. If the PRS requests enlargements or strip maps for linear facility routes, the project owner shall provide copies to the PRS and the lead agency's CPM. The site grading plan and plan and profile drawings for the utility lines would be acceptable for this purpose. The plan drawings should show the location, depth, and extent of all ground disturbances and be at a scale between 1 inch = 40 feet and 1 inch = 100 feet. If the footprint of the project or its linear facilities changes, the project owner shall provide maps and drawings reflecting those changes to the PRS and the lead agency's CPM.

If construction of the project proceeds in phases, maps and drawings may be submitted prior to the start of each phase. A letter identifying the proposed schedule of each project phase shall be provided to the PRS and lead agency's CPM. Before work commences on affected phases, the project owner shall notify the PRS and the lead agency's CPM of any construction phase scheduling changes.

At a minimum, the project owner shall ensure that the PRS or PRM consults weekly with the project superintendent or construction field manager to confirm area(s) to be worked the following week and until ground disturbance is completed.

OEHI PAL-3 The project owner shall ensure that the PRS prepares, and the project owner submits to the lead agency's CPM for review and approval, a Paleontological Resources Monitoring and Mitigation Plan (PRMMP) to identify general and specific measures to minimize potential impacts to significant paleontological resources. Approval of the PRMMP by the lead agency's CPM shall occur prior to any ground disturbance. The PRMMP shall function as the formal guide for monitoring, collecting, and sampling activities and may be modified with lead agency's CPM approval. This document shall be used as the basis of discussion when on-site decisions or changes are proposed. Copies of the PRMMP shall reside with the PRS, each monitor, the project owner's on-site manager, and the lead agency's CPM.

The PRMMP shall be developed in accordance with the guidelines of the SVP (1995) and shall include, but not be limited, to the following:

1. Assurance that the performance and sequence of project-related tasks, such as any literature searches, pre-construction surveys, worker environmental training, fieldwork, flagging or staking, construction monitoring, mapping and data recovery, fossil preparation and collection, identification and inventory, preparation of final reports, and transmittal of materials for curation will be performed according to PRMMP procedures;
2. Identification of the person(s) expected to assist with each of the tasks identified within the PRMMP and the conditions of certification;
3. A thorough discussion of the anticipated geologic units expected to be encountered, the location and depth of the units relative to the project when known, and the known sensitivity of those units based on the occurrence of fossils either in that unit or in correlative units;
4. An explanation of why, how, and how much sampling is expected to take place and in what units. Include descriptions of different sampling procedures that shall be used for fine-grained and coarse-grained units;
5. A discussion of the locations of where the monitoring of project construction activities is deemed necessary, and a proposed plan for monitoring and sampling;
6. A discussion of procedures to be followed in the event of a significant fossil discovery, halting construction, resuming construction, and how notifications will be performed;
7. A discussion of equipment and supplies necessary for collection of fossil materials and any specialized equipment needed to prepare, remove, load, transport, and analyze large-sized fossils or extensive fossil deposits;
8. Procedures for inventory, preparation, and delivery for curation into a retrievable storage collection in a public repository or museum, which meet the Society of Vertebrate Paleontology's standards and requirements for the curation of paleontological resources;
9. Identification of the institution that has agreed to receive data and fossil materials collected, requirements or specifications for materials delivered for curation and how they will be met, and the name and phone number of the contact person at the institution; and
10. A copy of the paleontological recommended mitigation measures.

OEHI PAL-4 Prior to ground disturbance and for the duration of construction activities involving ground disturbance, the project owner and the PRS shall prepare and conduct weekly CPM-approved training for the following workers: project managers, construction supervisors, foremen and general workers involved with or who operate ground-disturbing equipment or tools. Workers shall not excavate in sensitive units prior to receiving CPM-approved worker training. Worker training shall consist of an initial in-person PRS training program, or may utilize a CPM-approved video or other presentation format, during the project kick off for those mentioned above. Following initial training, a CPM-approved video or other approved training presentation/materials, or in-person training may be used for new employees. The training program may be combined with other training programs prepared for cultural and biological resources, hazardous materials, or other areas of interest or concern. No ground disturbance shall occur prior to the lead agency's CPM approval of the Worker Environmental Awareness Program (WEAP), unless specifically approved by the lead agency's CPM.

The WEAP shall address the possibility of encountering paleontological resources in the field, the sensitivity and importance of these resources, and legal obligations to preserve and protect those resources.

The training shall include:

1. A discussion of applicable laws and penalties under the law;
2. Good quality photographs or physical examples of vertebrate fossils for project sites containing units of high paleontologic sensitivity;
3. Information that the PRS or PRM has the authority to halt or redirect construction in the event of a discovery or unanticipated impact to a paleontological resource;
4. Instruction that employees are to halt or redirect work in the vicinity of a find and to contact their supervisor and the PRS or PRM;
5. An informational brochure that identifies reporting procedures in the event of a discovery;
6. A WEAP certification of completion form signed by each worker indicating that he/she has received the training; and
7. A sticker that shall be placed on hard hats indicating that environmental training has been completed.

OEHI PAL-5 The project owner shall ensure that the PRS and PRM(s) monitor consistent with the PRMMP all construction-related grading, excavation, trenching, and augering in areas where potential fossil-bearing materials have been identified, both at the site and along any constructed linear facilities associated with the project. In the event that the PRS determines full-time monitoring is not necessary in locations that were identified as potentially fossil bearing in the PRMMP, the project owner shall notify and seek the concurrence of the lead agency's CPM.

The project owner shall ensure that the PRS and PRM(s) have the authority to halt or redirect construction if paleontological resources are encountered. The project owner shall ensure that there is no interference with monitoring activities unless directed by the PRS. Monitoring activities shall be conducted as follows:

1. Any change of monitoring from the accepted schedule in the PRMMP shall be proposed in a letter or email from the PRS and the project owner to the lead agency's CPM prior to the change in monitoring and will be included in the monthly compliance report. The letter or email shall include the

justification for the change in monitoring and be submitted to the lead agency's CPM for review and approval.

2. The project owner shall ensure that the PRM(s) keep a daily monitoring log of paleontological resource activities. The PRS may informally discuss paleontological resource monitoring and mitigation activities with the lead agency's CPM at any time.
3. The project owner shall ensure that the PRS notifies the lead agency's CPM within 24 hours of the occurrence of any incidents of non-compliance with any paleontological resources conditions of certification. The PRS shall recommend corrective action to resolve the issues or achieve compliance with the conditions of certification.
4. For any significant paleontological resources encountered, either the project owner or the PRS shall notify the lead agency's CPM within 24 hours, or Monday morning in the case of a weekend event, where construction has been halted because of a paleontological find.

The project owner shall ensure that the PRS prepares a summary of monitoring and other paleontological activities placed in the monthly compliance reports. The summary will include the name(s) of PRS or PRM(s) active during the month; general descriptions of training and monitored construction activities; and general locations of excavations, grading, and other activities. A section of the report shall include the geologic units or subunits encountered, descriptions of samplings within each unit, and a list of identified fossils. A final section of the report will address any issues or concerns about the project relating to paleontologic monitoring, including any incidents of non-compliance or any changes to the monitoring plan that have been approved by the lead agency's CPM. If no monitoring took place during the month, the report shall include an explanation in the summary as to why monitoring was not conducted.

OEHI PAL-6 The project owner, through the designated PRS, shall ensure that all components of the PRMMP are adequately performed including collection of fossil materials, preparation of fossil materials for analysis, analysis of fossils, identification and inventory of fossils, the preparation of fossils for curation, and the delivery for curation of all significant paleontological resource materials encountered and collected during project construction. The project owner shall be responsible for paying any curation fees charged by the museum for fossils collected and curated as a result of paleontological mitigation.

OEHI PAL-7 The project owner shall ensure preparation of a Paleontological Resources Report (PRR) by the designated PRS. The PRR shall be prepared following completion of the ground-disturbing activities at each well pad and at any construction site. The PRR shall include an analysis of the collected fossil materials and related information and submit it to the lead agency's CPM for review and approval.

The report shall include, but is not limited to, a description and inventory of recovered fossil materials; a map showing the location of paleontological resources encountered; determinations of sensitivity and significance; and a statement by the PRS that project impacts to paleontological resources have been mitigated below the level of significance.

PROPOSED CONDITIONS OF CERTIFICATION

The Energy Commission does have jurisdiction over compliance with LORS and mitigation of impacts resulting from construction and operation of HECA. Therefore, staff proposes the following Conditions of Certification.

General conditions of certification with respect to engineering geology are proposed under Conditions of Certification **GEN-1, GEN-5**, and **CIVIL-1** in the **Facility Design** section. Proposed Geological Conditions of Certification follow.

GEO-1 The Soils Engineering Report required by Section 1803 of the 2010 CBC should specifically include laboratory test data, associated geotechnical engineering analyses, and a thorough discussion of hydrocompaction or dynamic compaction; and the presence of expansive clay soils. The report should also include recommendations for ground improvement and/or foundation systems necessary to mitigate these potential geologic hazards, if present.

Verification: The project owner shall include in the application for a grading permit a copy of the Soils Engineering Report which addresses the potential for liquefaction; settlement due to compressible soils, ground water withdrawal, hydrocompaction, or dynamic compaction; and the possible presence of expansive clay soils, and a summary of how the results of the analyses were incorporated into the project foundation and grading plan design for review and comment by the Chief Building Official (CBO). A copy of the Soils Engineering Report, application for grading permit and any comments by the CBO shall be provided to the CPM at least 30 days prior to grading.

Proposed paleontological conditions of certification are listed below. It is staff's opinion that the likelihood of encountering paleontologic resources is high at the plant site and along project linears. Staff will consider reducing monitoring intensity, at the recommendation of the project paleontologic resource specialist (PRS), following examination of sufficient, representative deep excavations that produce no significant fossil remains.

PAL-1 The project owner shall provide the CPM with the resume and qualifications of its PRS for review and approval. If the approved PRS is replaced prior to completion of project mitigation and submittal of the Paleontological Resources Report, the project owner shall obtain CPM approval of the replacement PRS. The project owner shall keep resumes on file for qualified paleontological resource monitors (PRMs). If a PRM is replaced, the resume of the replacement PRM shall also be provided to the CPM.

The PRS resume shall include the names and phone numbers of references. The resume shall also demonstrate to the satisfaction of the CPM the appropriate education and experience to accomplish the required paleontological resource tasks.

As determined by the CPM, the PRS shall meet the minimum qualifications for a vertebrate paleontologist as described in the SVP guidelines of 1995. The experience of the PRS shall include the following:

1. Institutional affiliations, appropriate credentials, and college degree;
2. Ability to recognize and collect fossils in the field;
3. Local geological and biostratigraphic expertise;
4. Proficiency in identifying vertebrate and invertebrate fossils; and
5. At least three years of paleontological resource mitigation and field experience in California and at least one year of experience leading paleontological resource mitigation and field activities.

The project owner shall ensure that the PRS obtains qualified paleontological resource monitors to monitor as he or she deems necessary on the project. Paleontologic resource monitors shall have the equivalent of the following qualifications:

- BS or BA degree in geology or paleontology and one year of experience monitoring in California; or
- AS or AA in geology, paleontology, or biology and four years' experience monitoring in California; or
- Enrollment in upper division classes pursuing a degree in the fields of geology or paleontology and two years of monitoring experience in California.

Verification: (1) At least 60 days prior to the start of ground disturbance, the project owner shall submit a resume and statement of availability of its designated PRS for on-site work.

(2) At least 20 days prior to ground disturbance, the PRS or project owner shall provide a letter with resumes naming anticipated monitors for the project, stating that the identified monitors meet the minimum qualifications for paleontological resource monitoring required by the condition. If additional monitors are obtained during the project, the PRS shall provide additional letters and resumes to the CPM. The letter shall be provided to the CPM no later than one week prior to the monitor's beginning on-site duties.

(3) Prior to the termination or release of a PRS, the project owner shall submit the resume of the proposed new PRS to the CPM for review and approval.

PAL-2 The project owner shall provide to the PRS and the CPM, for approval, maps and drawings showing the footprint of the power plant, construction lay-down areas, and all related facilities. Maps shall identify all areas of the project where ground disturbance is anticipated. If the PRS requests enlargements or strip maps for linear facility routes, the project owner shall provide copies to the PRS and CPM. The site grading plan and plan and profile drawings for the utility lines would be acceptable for this purpose. The plan drawings should show the location, depth, and extent of all ground disturbances and be at a scale between 1 inch = 40 feet and 1 inch = 100 feet. If the footprint of the project or its linear facilities changes, the project owner shall provide maps and drawings reflecting those changes to the PRS and CPM.

If construction of the project proceeds in phases, maps and drawings may be submitted prior to the start of each phase. A letter identifying the proposed schedule of each project phase shall be provided to the PRS and CPM. Before work commences on affected phases, the project owner shall notify the PRS and CPM of any construction phase scheduling changes.

At a minimum, the project owner shall ensure that the PRS or PRM consults weekly with the project superintendent or construction field manager to confirm area(s) to be worked the following week and until ground disturbance is completed.

Verification: (1) At least 30 days prior to the start of ground disturbance, the project owner shall provide the maps and drawings to the PRS and CPM.

(2) If there are changes to the footprint of the project, revised maps and drawings shall be provided to the PRS and CPM at least 15 days prior to the start of ground disturbance.

(3) If there are changes to the scheduling of the construction phases, the project owner shall submit a letter to the CPM within 5 days of identifying the changes.

PAL-3 The project owner shall ensure that the PRS prepares, and the project owner submits to the CPM for review and approval, a Paleontological Resources Monitoring and Mitigation Plan (PRMMP) to identify general and specific measures to minimize potential impacts to significant paleontological resources. Approval of the PRMMP by the CPM shall occur prior to any ground disturbance. The PRMMP shall function as the formal guide for monitoring, collecting, and sampling activities and may be modified with CPM approval. This document shall be used as the basis of discussion when on-site decisions or changes are proposed. Copies of the PRMMP shall reside with the PRS, each monitor, the project owner’s on-site manager, and the CPM.

The PRMMP shall be developed in accordance with the guidelines of the SVP (1995) and shall include, but not be limited, to the following:

1. Assurance that the performance and sequence of project-related tasks, such as any literature searches, pre-construction surveys, worker environmental training, fieldwork, flagging or staking, construction monitoring, mapping and data recovery, fossil preparation and collection, identification and inventory,

preparation of final reports, and transmittal of materials for curation will be performed according to PRMMP procedures;

2. Identification of the person(s) expected to assist with each of the tasks identified within the PRMMP and the conditions of certification;
3. A thorough discussion of the anticipated geologic units expected to be encountered, the location and depth of the units relative to the project when known, and the known sensitivity of those units based on the occurrence of fossils either in that unit or in correlative units;
4. An explanation of why, how, and how much sampling is expected to take place and in what units. Include descriptions of different sampling procedures that shall be used for fine-grained and coarse-grained units;
5. A discussion of the locations of where the monitoring of project construction activities is deemed necessary, and a proposed plan for monitoring and sampling;
6. A discussion of procedures to be followed in the event of a significant fossil discovery, halting construction, resuming construction, and how notifications will be performed;
7. A discussion of equipment and supplies necessary for collection of fossil materials and any specialized equipment needed to prepare, remove, load, transport, and analyze large-sized fossils or extensive fossil deposits;
8. Procedures for inventory, preparation, and delivery for curation into a retrievable storage collection in a public repository or museum, which meet the Society of Vertebrate Paleontology's standards and requirements for the curation of paleontological resources;
9. Identification of the institution that has agreed to receive data and fossil materials collected, requirements or specifications for materials delivered for curation and how they will be met, and the name and phone number of the contact person at the institution; and
10. A copy of the paleontological conditions of certification.

Verification: At least 30 days prior to ground disturbance, the project owner shall provide a copy of the PRMMP to the CPM. The PRMMP shall include an affidavit of authorship by the PRS and acceptance of the PRMMP by the project owner evidenced by a signature.

PAL-4 Prior to ground disturbance and for the duration of construction activities involving ground disturbance, the project owner and the PRS shall prepare and conduct weekly CPM-approved training for the following workers: project managers, construction supervisors, foremen and general workers involved with or who operate ground-disturbing equipment or tools. Workers shall not excavate in sensitive units prior to receiving CPM-approved worker training. Worker training shall consist of an initial in-person PRS training program, or may utilize a CPM-approved video or other presentation format, during the project kick off for those mentioned above. Following initial training, a CPM-approved video or other approved training presentation/materials, or in-person training may be used for new employees. The training program may be combined with other training programs prepared for cultural and biological resources, hazardous materials, or other areas of interest or concern. No ground disturbance shall occur prior to CPM approval of the Worker Environmental Awareness Program (WEAP), unless specifically approved by the CPM.

The WEAP shall address the possibility of encountering paleontological resources in the field, the sensitivity and importance of these resources, and legal obligations to preserve and protect those resources.

The training shall include:

1. A discussion of applicable laws and penalties under the law;
2. Good quality photographs or physical examples of vertebrate fossils for project sites containing units of high paleontologic sensitivity;
3. Information that the PRS or PRM has the authority to halt or redirect construction in the event of a discovery or unanticipated impact to a paleontological resource;
4. Instruction that employees are to halt or redirect work in the vicinity of a find and to contact their supervisor and the PRS or PRM;
5. An informational brochure that identifies reporting procedures in the event of a discovery;
6. A WEAP certification of completion form signed by each worker indicating that he/she has received the training; and
7. A sticker that shall be placed on hard hats indicating that environmental training has been completed.

Verification: (1) At least 30 days prior to ground disturbance, the project owner shall submit the proposed WEAP, including the brochure, with the set of reporting procedures for workers to follow, to the CPM for review and approval.

(2) At least 30 days prior to ground disturbance, the project owner shall submit the training program presentation/materials to the CPM for approval if the project owner is planning to use a presentation format other than an in-person trainer for training.

(3) At least 30 days prior to ground disturbance, the project owner shall submit the script and final video to the CPM for approval if the project owner is planning to use a video for interim training.

(4) If the owner requests the use of an alternate paleontological trainer, the resume and qualifications of the trainer shall be submitted to the CPM for review and approval prior to installation of an alternate trainer. Alternate trainers shall not conduct training prior to CPM authorization.

(5) In the monthly compliance report (MCR), the project owner shall provide copies of the WEAP certification of completion forms with the names of those trained and the

trainer or type of training (in-person or other approved presentation format) offered that month. The MCR shall also include a running total of all persons who have completed the training to date.

PAL-5 The project owner shall ensure that the PRS and PRM(s) monitor consistent with the PRMMP all construction-related grading, excavation, trenching, and augering in areas where potential fossil-bearing materials have been identified, both at the site and along any constructed linear facilities associated with the project. In the event that the PRS determines full-time monitoring is not necessary in locations that were identified as potentially fossil bearing in the PRMMP, the project owner shall notify and seek the concurrence of the CPM.

The project owner shall ensure that the PRS and PRM(s) have the authority to halt or redirect construction if paleontological resources are encountered. The project owner shall ensure that there is no interference with monitoring activities unless directed by the PRS. Monitoring activities shall be conducted as follows:

1. Any change of monitoring from the accepted schedule in the PRMMP shall be proposed in a letter or email from the PRS and the project owner to the CPM prior to the change in monitoring and will be included in the monthly compliance report. The letter or email shall include the justification for the change in monitoring and be submitted to the CPM for review and approval.
2. The project owner shall ensure that the PRM(s) keep a daily monitoring log of paleontological resource activities. The PRS may informally discuss paleontological resource monitoring and mitigation activities with the CPM at any time.
3. The project owner shall ensure that the PRS notifies the CPM within 24 hours of the occurrence of any incidents of non-compliance with any paleontological resources conditions of certification. The PRS shall recommend corrective action to resolve the issues or achieve compliance with the conditions of certification.
4. For any significant paleontological resources encountered, either the project owner or the PRS shall notify the CPM within 24 hours, or Monday morning in the case of a weekend event, where construction has been halted because of a paleontological find.

The project owner shall ensure that the PRS prepares a summary of monitoring and other paleontological activities placed in the monthly compliance reports. The summary will include the name(s) of PRS or PRM(s) active during the month; general descriptions of training and monitored construction activities; and general locations of excavations, grading, and other activities. A section of the report shall include the geologic units or subunits encountered, descriptions of samplings within each unit, and a list of identified fossils. A final section of the report will address any issues or concerns about the project relating to paleontologic monitoring, including any incidents of non-compliance or any changes to the monitoring plan that have been approved by the CPM. If no monitoring took place during the month, the report shall include an explanation in the summary as to why monitoring was not conducted.

Staff will consider reducing monitoring intensity, at the recommendation of the project PRS, following examination of sufficient, representative deep excavations that produce no significant fossil remains.

Verification: The project owner shall ensure that the PRS submits the summary of monitoring and paleontological activities in the MCR. When feasible, the CPM shall be notified 10 days in advance of any proposed changes in monitoring different from the plan identified in the PRMMP. If there is any unforeseen change in monitoring, the notice shall be given as soon as possible prior to implementation of the change.

PAL-6 The project owner, through the designated PRS, shall ensure that all components of the PRMMP are adequately performed including collection of fossil materials, preparation of fossil materials for analysis, analysis of fossils, identification and inventory of fossils, the preparation of fossils for curation, and the delivery for curation of all significant paleontological resource materials encountered and collected during project construction. The project owner shall be responsible for paying any curation fees charged by the museum for fossils collected and curated as a result of paleontological mitigation.

Verification: The project owner shall maintain in his/her compliance file copies of signed contracts or agreements with the designated PRS and other qualified research specialists. The project owner shall maintain these files for a period of three years after project completion and approval of the CPM-approved paleontological resource report (see Condition of Certification **PAL-7**). A copy of the letter of transmittal submitting the fossils to the curating institution shall be provided to the CPM.

PAL-7 The project owner shall ensure preparation of a Paleontological Resources Report (PRR) by the designated PRS. The PRR shall be prepared following completion of the ground-disturbing activities. The PRR shall include an analysis of the collected fossil materials and related information and submit it to the CPM for review and approval.

The report shall include, but is not limited to, a description and inventory of recovered fossil materials; a map showing the location of paleontological resources encountered; determinations of sensitivity and significance; and a statement by the PRS that project impacts to paleontological resources have been mitigated below the level of significance.

Verification: Within 90 days after completion of ground-disturbing activities, including landscaping, the project owner shall submit the PRR under confidential cover to the CPM for review and approval.

Certification of Completion
Worker Environmental Awareness Program
Hydrogen Energy California Project (08-AFC-8)

This is to certify these individuals have completed a mandatory California Energy Commission-approved Worker Environmental Awareness Program (WEAP). The WEAP includes pertinent information on cultural, paleontological, and biological resources for all personnel (that is, construction supervisors, crews, and plant operators) working on site or at related facilities. By signing below, the participant indicates that he/she understands and shall abide by the guidelines set forth in the program materials. Include this completed form in the Monthly Compliance Report.

No.	Employee Name	Title/Company	Signature
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Cultural Trainer: ______________ Signature:___________________ Date: ___/___/____

PaleoTrainer: _______________ Signature:___________________ Date: ___/___/____

Biological Trainer: ______________Signature:________________ Date:___/___/__

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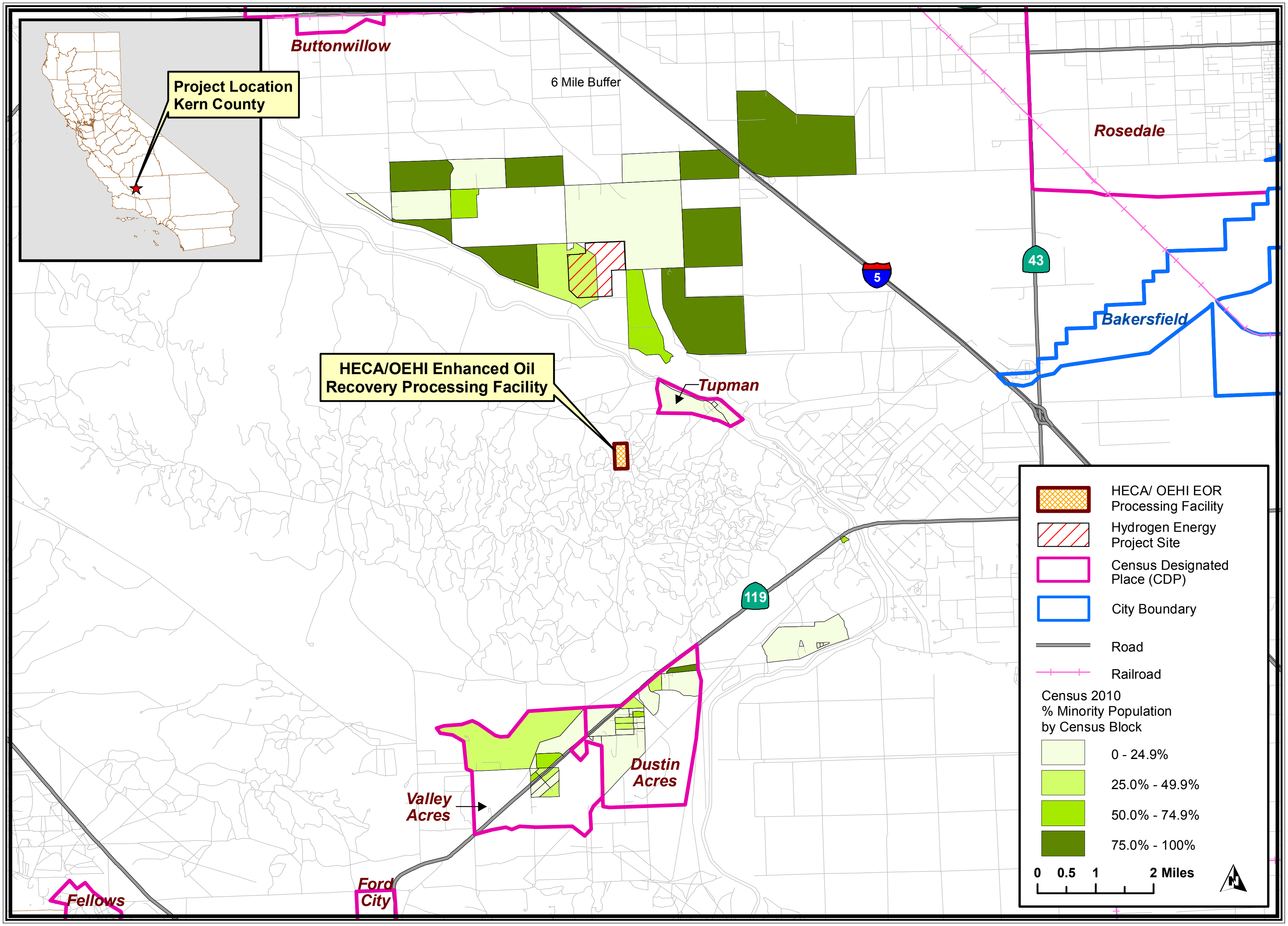
GEOLOGY AND PALEONTOLOGY - FIGURE 1

Hydrogen Energy California [08-AFC-08A] - HECA/OEHI Enhanced Oil Recovery Processing Facility



GEOLOGY AND PALEONTOLOGY

CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING DIVISION

SOURCE: California Energy Commission Statewide Power Plant Maps 2011 - Census 2010 PL 94-171 Data

GEOLOGY AND PALEONTOLOGY - FIGURE 2

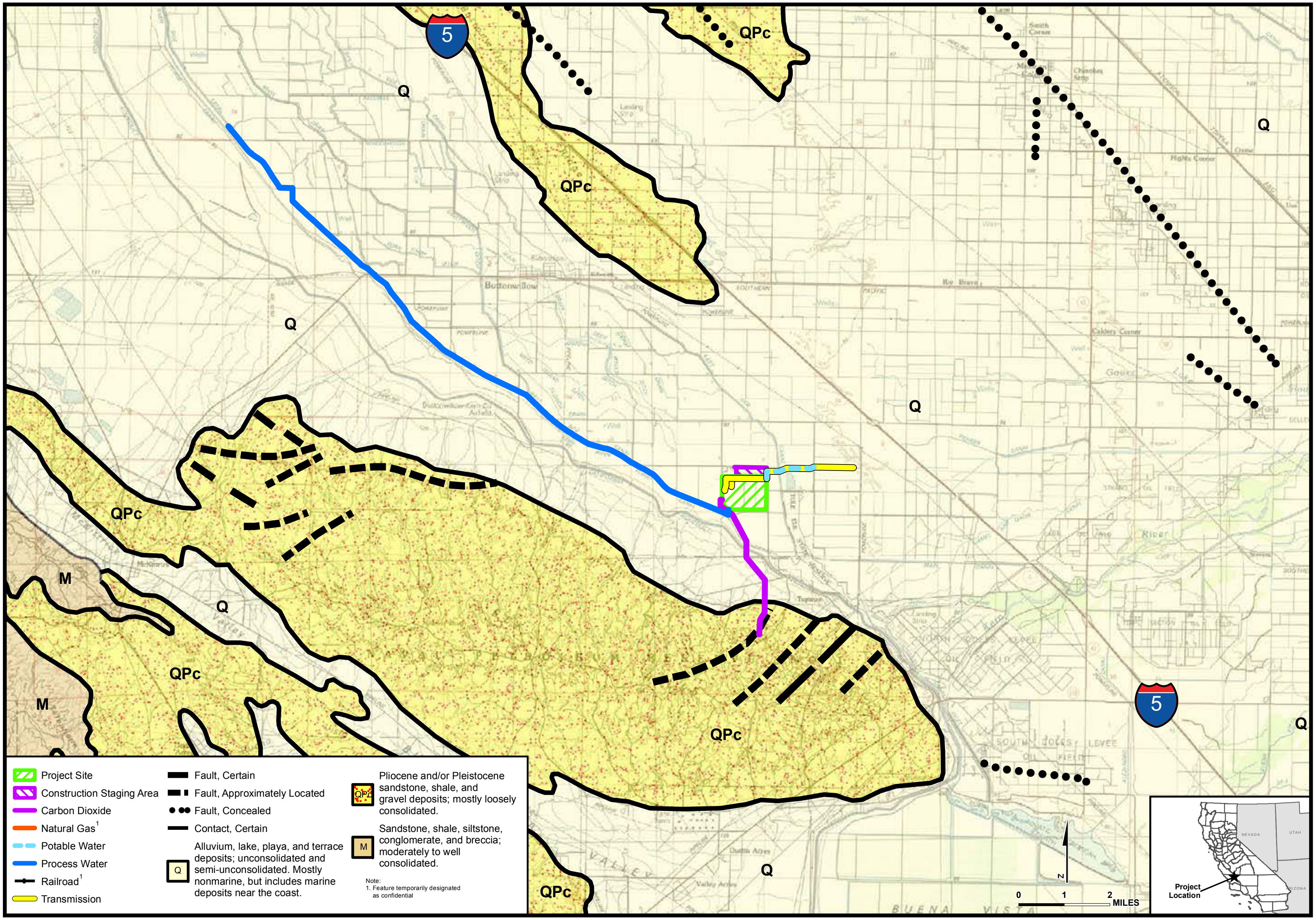
Hydrogen Energy California (HECA) - Geormorphic Provinces

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: URS - California Department of Conservation, California Geological Survey, 2002.

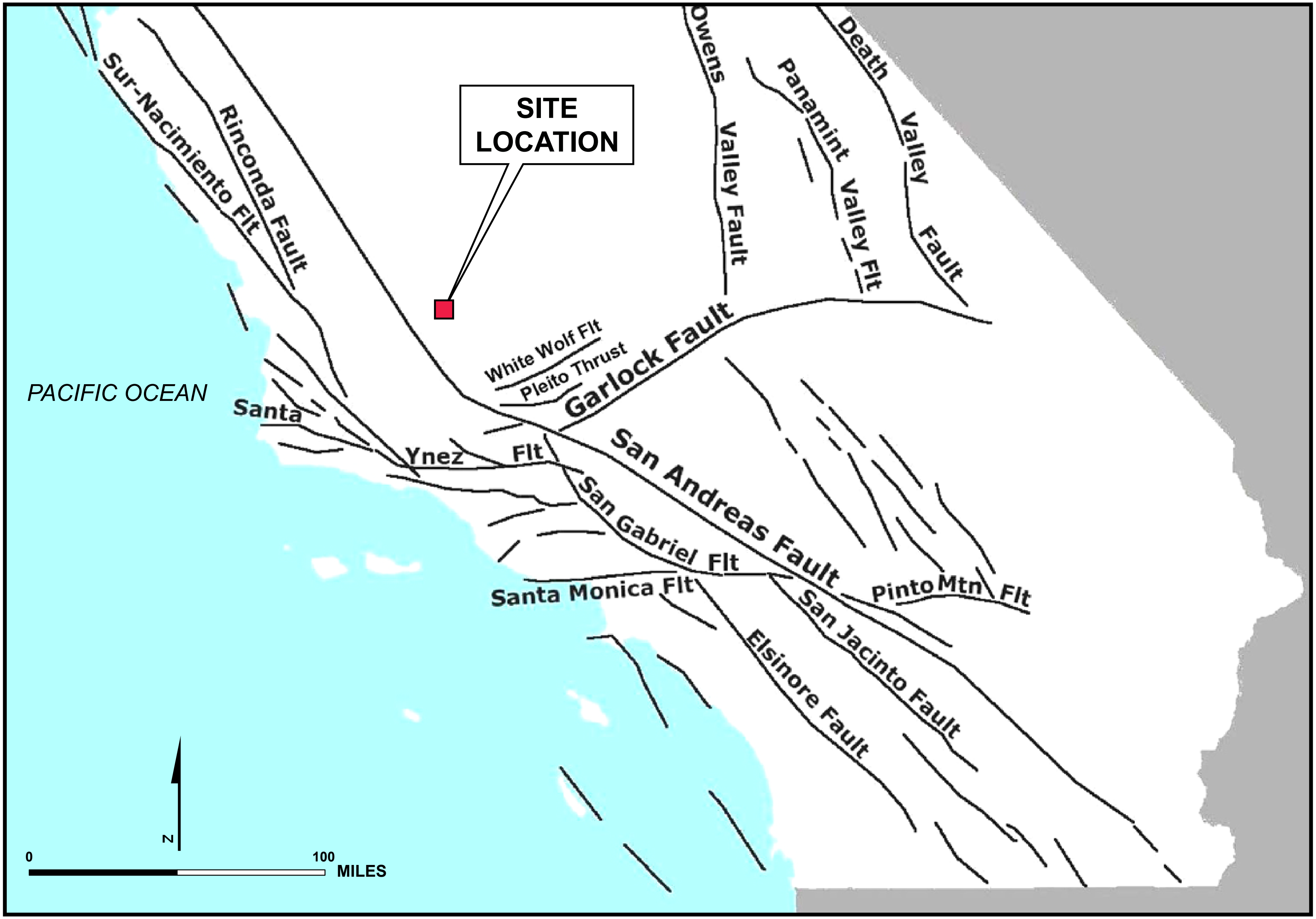
GEOLOGY AND PALEONTOLOGY - FIGURE 3

Hydrogen Energy California - Regional Project Location Map - Regional Geologic Map of Project



SOURCE: URS - AFC April 12, 2012, Figure 5.15-4

GEOLOGY AND PALEONTOLOGY - FIGURE 4
Hydrogen Energy California - Major Faults of Southern California



GEOLOGY AND PALEONTOLOGY

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION
SOURCE: URS - AFC April 12, 2012, Figure 5.15-3

POWER PLANT EFFICIENCY

Edward Brady

SUMMARY OF CONCLUSIONS

Please note that for the project's rated power capacity, staff uses 405 megawatt (MW) in this section of the Preliminary Staff Assessment/Draft Environmental Impact Statement (PSA/DEIS) despite the 431 MW capacity rating used elsewhere in the PSA. No information on the overall project heat rate and breakdown of auxiliary loads, based on the 431MW figure, is available to staff at this point in time. Staff will need to prepare the Final Staff Assessment/Final Environmental Impact Statement (FSA/FEIS) based on a corrected MW figure.

Based on the 405 MW figure, the combined cycle component of the project would generate a maximum net output of 158 MW using its primary fuel of hydrogen rich syngas produced from gasified coal and petroleum coke. The coal/coke/syngas produces a net fuel efficiency of 22.8 percent at lower heating value (LHV). In the back-up mode, the combined cycle plant would produce a net output of 300 MW using its secondary fuel of 100 percent natural gas with a net 50.3 percent efficiency at LHV at maximum full load and annual design ambient conditions[1].

While the project would internally consume substantial amounts of energy, it would still produce electricity in a reasonably efficient manner and still meet the project objectives of demonstrating the viability of carbon capture and sequestration, enhanced oil recovery, and the co-production of fertilizer products. It would not create significant adverse effects on energy supplies or resources. No energy efficiency standards apply to the project. Staff therefore concludes that the project would present no significant adverse impacts upon energy resources.

INTRODUCTION

The Energy Commission staff (staff) makes a recommendation as to whether energy use by Hydrogen Energy California (HECA) would result in significant adverse impacts on the environment, as defined in the California Environmental Quality Act (CEQA). If staff concludes that the HECA's consumption of energy would create a significant adverse impact, it must determine whether there are any feasible mitigation measures that could eliminate or minimize the impacts. In this analysis, staff addresses the issue of inefficient and unnecessary consumption of energy.

In order to support the staff's recommendations, this analysis:

- examines whether the facility would likely present any adverse impacts upon energy resources;
- examines whether these adverse impacts would be significant; and if so,

[1] At site temperature of 97°F with 20 percent humidity (HECA 2012a, AFC Table 2-2).

- examines whether feasible mitigation measures exist that would eliminate the adverse impacts, or reduce them to a level of less than significant.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

No Federal, State or local/county laws, ordinances, regulations or standards (LORS) apply to the efficiency of this project.

SETTING

The aggregation of the power block, fuel gasification, fertilizer production, and CO_2 transmission system is designated as an integrated gasification combined cycle (IGCC) project, designated HECA in this analysis.

Hydrogen Electric California LLC, the applicant, proposes to construct and operate HECA. As explained above, staff uses the original 405 MW capacity rating in this section of the PSA, instead of 431 MW used elsewhere in the PSA. This project would provide the flexibility to energize its own fuel conversion from a 75 percent sub-bituminous coal/25 percent petroleum coke (petcoke) feedstock mixture to low-carbon hydrogen-rich syngas; pressurize and transmit compressed carbon dioxide for petroleum extraction; deliver power to the manufacturing complex; and generate up to 158 MW (nominal net) for delivery to the electric power distribution system. The combined cycle power block would consist of a one-on-one power train with a single shaft Mitsubishi Heavy Industries (MHI) 501GAC combustion gas turbine generator (CTG), heat recovery steam generator (HRSG), and steam turbine generator (STG).

The project would incorporate a feedstock delivery/storage/handling system, gasifier unit, acid gas removal system, sulfur removal unit, ammonia synthesis unit, and carbon dioxide (CO_2) purification and compression facility. The fuel gasification system would capture carbon dioxide for delivery to the Elk Hills Oil Fields (EHOF) three miles away for use in the enhanced oil recovery (EOR) and carbon sequestration fields. The air separation unit (ASU) would be powered from the grid and would provide an on-site source of oxygen for use in the gasifier and nitrogen for ammonia generation. In turn, the ammonia would be used in the power block's low NO_X combustion emissions system and the ammonia manufacturing complex.

The integrated manufacturing complex would take nitrogen generated in the ASU using a method called pressure swing adsorption (PSA) to manufacture products such as nitric acid, ammonia nitrate and urea. In addition, the complex would purify the compressed carbon dioxide for urea pastillation (pelletization of the urea) along with sending compressed CO_2 to the EHOF (HECA 2012a, § 2.1.9). Urea is a convenient source of nitrogen for use as agricultural fertilizer. Two molecules of ammonia combine with one molecule of carbon dioxide to make urea and water [$2NH_3 + CO_2 \rightarrow (NH_2)_2CO + H_2O$]. The HECA design specifies that, at maximum power production, about 14.8% of the CO_2 released in the fuel gasification process would be used to make urea fertilizer, which would then be pelletized in a method called pastillation.

The linear utilities and transportation system would comprise the balance of off-site functions that support HECA. A combination of rail and truck transportation would be used to deliver the feedstock constituents to HECA and return the sulfur, solids products and ash generated from the fuel gasification system. Alternative 1 would include a 5-mile rail spur to the site from the San Joaquin Valley Railroad (SJVRR) Buttonwillow rail line. Alternative 2 would use truck transport from the coal terminus 27 miles away in Wasco to deliver coal. Petroleum coke would be transported by truck in both alternatives from refineries in Santa Maria and the Los Angeles area.

HECA would utilize natural gas as a back-up source of fuel to be used during gasifier shutdown and planned maintenances (HECA 2012a, § 2.9.2). The natural gas pipeline would be routed 13 miles and interconnected with an available PG&E pipeline (HECA 2012a, § 2.1.11.6). The project would use raw water provided by Buena Vista Water Storage District, which would deliver an average 4,600 gallons per minute (gpm) annually and a peak demand of 5,150 gpm (HECA 2012a, § 2.11.7, Figures 2-10 and 2-11). The project's water use efficiency is evaluated in the **Water Supply** section of this PSA.

Of the 10,800 short tons per day (stpd) of CO_2 released from the sour shift and acid gas removal processes, 9,200 stpd (85.2 percent) are transferred to the EOR for field sequestration. The balance of CO_2 (1,600 stpd or 14.8%) is purified and delivered to the manufacturing complex for chemically processing solid ammonia-based processes such as pastillation (HECA 2012a, Response to Data Request A25, Figure A-27.1). Approximately 40 MW of the total auxiliary (internal) power is assigned to CO_2 compression, i.e., 34 MW for CO_2 EOR compression and transmission, and 6 MW for manufacturing.

ASSESSMENT OF IMPACTS

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE OF IMPACTS TO ENERGY RESOURCES

CEQA Guidelines state that the environmental analysis "…shall describe feasible measures which could minimize significant adverse impacts, including where irrelevant, inefficient and unnecessary consumption of energy" (Cal. Code Regs., tit. 14, § 15126.4(a)(1)). Appendix F of the Guidelines further suggests consideration of such factors as the project's energy requirements and energy use efficiency; its effects on local and regional energy supplies and energy resources; its requirements for additional energy supply capacity; its compliance with existing energy standards; and any alternatives that could reduce wasteful, inefficient and unnecessary consumption of energy (Cal. Code Regs., tit. 14, § 15000 et seq., Appendix F).

The inefficient and unnecessary consumption of energy, in the form of non-renewable fuels such as natural gas, petcoke, coal, and oil, constitutes an adverse environmental impact. An adverse impact would be considered significant if it results in:

- adverse effects on local and regional energy supplies and energy resources;
- a requirement for additional energy supply capacity;

- noncompliance with existing energy standards; or
- the wasteful, inefficient and unnecessary consumption of fuel or energy.

PROJECT ENERGY REQUIREMENTS AND ENERGY USE EFFICIENCY

Any power plant large enough to fall under Energy Commission siting jurisdiction will consume large amounts of energy. Under average ambient conditions, HECA would process the 75 percent coal/25 percent petcoke feedstock into low-carbon/hydrogen-rich fuel at approximately 3,992 million Btu[2] per hour LHV and natural gas nominal rate of 2,034 million Btu per hour LHV (HECA 2012a, Table 2-10). The primary hydrogen fuel is limited only by the amount of feedstock products that will be delivered and stored at the project site. The secondary natural gas flow rate is a substantial rate of energy consumption, and holds the potential to impact energy supplies. But because it is a back-up fuel utilized to generate electrical power when the IGCC is down for planned maintenance, this demand on the natural gas supply would be intermittent, i.e. two one-week planned shutdowns under cold-start conditions would be 528 hours or about 6% annually.

Under typical ambient conditions, electricity would be generated using natural gas at a full load efficiency optimized for power production of approximately 50.3 percent LHV (HECA 2012a, Tables 2-4 through 2-11)[3].

ADVERSE EFFECTS ON ENERGY SUPPLIES AND RESOURCES AND ADDITIONAL ENERGY SUPPLY REQUIREMENTS

HECA would rely on the availability of petcoke and sub-bitumnous coal for the feedstock mixture of 75 percent coal and 25 percent petcoke. The base production rate assumes that the consumption of coal would be 4,580 stpd (short tons per day) or 1,600,000 short tons per year (stpy) (HECA 2012a, §2.1.11.2). Approximately 16,000 stpd or 6.0 million stpy of petcoke would provide the balance of the feedstock mixture. HECA expects to obtain western sub-bituminous coal from New Mexico. Fuel-grade petcoke would be available from existing refineries in Southern California and plant demand would consume about 7 percent of the existing petcoke production within California (HECA 20 12a, §§ 2.1.11.2, 2.1.11.3); this would not likely create a significant adverse impact on the other petcoke customers. (Petcoke customers primarily consist of customers in Far East and southern Asia.)

For the natural gas fuel, the applicant has described its source of supply of natural gas for the project (HECA 2012a, § 2.7.1.10, Table 2-10). Natural gas for the HECA project is used as a back-up fuel and would be supplied from an existing PG&E natural gas transmission pipeline. The PG&E natural gas system has access to gas from the Rocky Mountains, Canada and the southwest. This represents a resource of considerable capacity. It is therefore highly unlikely that the project would pose a significant adverse impact on natural gas supplies in California.

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[2] British thermal units.

[3] Tables 2-4 through 2-11 provide high heating values (HHV). Tabulation of lower heating values (LHV) is used an industry standard. Derived LHV's based on the above referenced tables and 2011 Biomass Energy Data Book: Appendix A.

There is abundant supply of coal in the country; the coal resources stretch from Montana to New Mexico in the west and from West Virginia to Pennsylvania in the east. The project would receive coal from New Mexico. The resource in New Mexico from which the project would draw coal from has a capacity of 21,922,000 stpy. The project's annual consumption of coal would be 1,600,000 stpy, approximately 7.3 percent of the available resource from New Mexico alone, and approximately 1.3 percent of the overall capacity in the entire western region, 120,853,000 stpy.[4] There is no real likelihood that HECA would require the development of additional resources of coal or create a significant adverse impact on the other consumers of coal in the region.

The project's CO_2 will be used in the EHOF to produce more oil than is possible without the CO_2.

COMPLIANCE WITH ENERGY STANDARDS

No standards apply to the efficiency of HECA or other non-cogeneration projects.

ALTERNATIVES TO REDUCE WASTEFUL, INEFFICIENT AND UNNECESSARY ENERGY CONSUMPTION

HECA could be deemed to create significant adverse impacts on energy resources if alternatives existed that would reduce the project's use of fuel. Evaluation of alternatives to the project that could reduce wasteful, inefficient or unnecessary energy consumption first requires examination of the project's energy consumption. Project fuel efficiency, and therefore its rate of energy consumption, is determined by the configuration of the power producing system and by the selection of equipment used to generate power.

Project Configuration

The project objective is to provide intermediate power generation services during periods of normal electrical demand. At the same time, power is provided on a continuous basis to provide energy using low carbon hydrogen fuel, to manufacture ammonia products and transmit, via pipeline, compressed CO_2 to EHOF for enhanced oil recovery (EOR) and carbon sequestration (HECA 2012a, AFC § 1.1). An integrated gasification combined cycle configuration is consistent with this objective. HECA would be configured as a single CTG coupled by a common shaft with a HRSG and STG; a one-on-one combined cycle train (HECA 2012a, AFC §§ 1.1, 2.3.1). As a combined cycle plant on primary hydrogen fuel derived from gasified coal/coke, the system would require a 4-6 day ramping cycle[5] from cold start that would include stabilization of the fuel gasification. As a matter of comparison, a combined cycle natural gas plant would require six to ten hours ramping time from cold-start to full power.

Equipment Selection

Modern gas turbines embody the most fuel-efficient electric generating technology available today. HECA would employ a Mitsubishi MPCP1 one-on-one combined cycle train with an MHI-501GAC CTG with a gross capacity of 405 MW.

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[4] U.S. Energy Information Administration, Annual Coal Report 2011, Table 1.

[5] Ramping is increasing and decreasing electrical output to meet fluctuating load requirements.

The MHI-501 CTG has a solid operational record and does not represent a design that uses high efficiency to justify a lower operating reliability. The combined cycle configuration with the MHI-501 Series G turbine was first developed in 1995 and the MHI-501 turbine frame has been commercially available since the early 1980's. These machines have proven to operate reliably. Also, the applicant proposes a one-year pilot operation before commercial use. Finally, a full scale 250 MW demonstration facility employing the Mitsubishi MHI-501G model was brought up to full power in Nakaso, Japan in 2007 and has been operational since. For these reasons, the reliance on a single CTG in a one-on-one configuration does not represent a measureable reduction in reliability.

The MHI-501GAC model is nominally rated at a combined cycle thermal efficiency of 59.2 percent LHV (GTW 2012). The HECA power block would produce a gross output of 405 MW. The auxiliary load of 247 MW (109 ASU power requirement + 138 of other loads) drops the net power output for availability on the grid to 158 MW. In the case of HECA, the "poly-generation" requirements of the fuel gasification, agricultural products manufacturing, and the onsite CO_2 compression and transmission draws the net output efficiency down to 13.5 percent LHV, with the ASU power requirement taken into account (HECA 2012a, Table 2-10; **Efficiency Table 1**).[6]

According to the applicant, HECA would operate at three optimal modes: 1) Optimal electric power generation using hydrogen fuel, 2) Optimal manufacturing complex operation using hydrogen fuel, and 3) Combined cycle operation using natural gas. **Efficiency Table 1** (entitled **Modes of Operation**) below provides a breakdown of these operating modes. The listed efficiencies are based on the feedstock input of a 75 percent blend of sub-bituminous coal and 25 percent petcoke.[7]

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[6] Descamps, C., Bouallou, C., Kanniche, M., "Efficiency of an Integrated Gasification Combined Cycle (IGCC) power plant including CO_2 removal", *Energy*, Vol. 33, Issue 6, June, 2008, pp. 874-881.

[7] Ibid., Eqn. (1), p. 877,

Efficiency Table 1
Modes of Operation

Description	Coal / Petroleum Coke IGCC						Natural Gas
	Maximum Power Production (Hydrogen Gas)			Maximum Manufacturing Complex Production (Hydrogen Gas)			Combined Cycle Power Production
Gross Power[8] Output (MW)	405			295			320
Auxiliary Loads	Power	Mfg	Total	Power	Mfg	Total	Total
Gasification Block[9]	20	10	30	15	15	30	
Power Block	12	--	12	12	--	12	
CO_2 Compression[10]	34	6	40	34	6	40	
Mfg. Complex	--	25	25	--	32	32	
Support Systems	21	10	31	15	16	31	
ASU[11]	73	36	109	50	53	103	
Total Aux. Loads (MW)	160	87	247	126	122	248	20
Net Power Output(MW)			158			47	300
Net Efficiency (LHV)			13.5%			---	50.3%

Note: Allocation of auxiliary loads based on the mass and energy flow rates provided in HECA 2012a, AFC Table 2-10, Figure A27-1 Simplified Block Flow Diagram and e-mail from KRushmore/URS to WWorl/CEC dated 4/25/13.

The measurement or level of thermodynamic efficiency is not mandated or prescribed by any mandatory standard. The only evaluative guideline is to compare HECA efficiencies with other systems of similar configuration. **Efficiency Table 2** (entitled **IGCC Cycle Comparisons**) provides a side-by-side comparison among HECA and other projects with carbon capture and sequestration and entrained flow gasifiers. When allocating auxiliary power requirements, HECA efficiency stands at 22.8 percent LHV[12] compared to the 36.4-38.5 percent range for the alternative IGCCs'. With comparable fuel heat rates, the efficiency difference can only be accounted for by the difference in the level of auxiliary power loads, where HECA comes in at an auxiliary/cross ration of 0.34, compared to 0.26-.27 to the system alternatives. In an effort to account for the

[8] HECA 2012a, Table 2-10 with modifications noted.

[9] Auxiliary load allocated to power block and industrial block based on mass flow rates specified in data request response Fig. A27-4 "Simplified Blcock Flow Diagram. For power block MW = (1289/3925) x 30 = 20. For manufacturing complex MW = (2636/3925) x 30 = 10 MW.

[10] Power requirement for CO_2 compression proportioned to mass flow from Fig. A27-4. For transfer to EOR, (9200/10800) x 40 = 34 MW. For use in pastillation, (1600/10800) x 40 = 6 MW.

[11] Air Separation Unit (ASU) power requirement not included in AFC Table 2-10. Value of 109 MW on-peak power requirement provided in e-mail response from Kathy Rushmore/URS dated 4/25/13. Allocated in same proportion as Gasefication Block.

[12] Higher Heating Value (HHV), called gross or total heating values, is the heat rate which includes the latent heat of evaporation. In the case of HECA, the feedstock constituents of coal and petcoke are furnished with 15.0 and 14.8 percent by weight moisture content respectively (HECA 2012a, AFC Tables 2-4 and 2-5). Lower Heating Value (LHV) excludes the latent heat of evaporation and by U. S. convention is the value that's used in a combustion-fuel engine. Because the gasification fuel is being furnished to the CTG with the moisture removed, the LHV is assumed where both heat values are not otherwise provided. HHV/LHV conversion ratio of 1.18 used.

difference, the net efficiency for HECA was calculated without the 109 MW ASU power load, yielding a 22.8 percent efficiency at LHV and a total auxiliary load ratio of 0.34. See **Efficiency Table 2**.

Efficiency Table 2
IGCC Cycle Comparison[13]
Net Plant Efficiency

Description	HECA	GE Radiant Case 2	CoP 2-Stage Case 4	Shell Dry Feed Case 6
Gross Output (MW) Auxiliary Load (MW) Net Output (MW) Efficiencies: η(net) LHV η(net) HHV Aux/Gross Ratio	**405.0** **138.0** **267.0** **22.8%** 19.3% **0.34**	**734.0** **190.8** **543.2** **38.5%** 32.6% **0.26**	**703.7** **190.1** **513.6** **36.4%** 30.9% **0.27**	**673.4** **176.5** **496.9** **36.9%** 31.3% **0.26**
ASU Load Requirement (MW)	**109**			
Net Output (MW) – Post ASU	**158**			
Fertilizer Manufacturing	Yes	No	No	No
CO_2 Capture and Sequestration	Yes	Yes	Yes	Yes

Air Separation Unit (ASU)

The ASU converts air into oxygen and nitrogen. The principle use of the oxygen is the conversion of coal and petroleum feedstocks into hydrogen-rich syngas. The nitrogen will be used for agricultural products manufacturing and as a NO_x moderator in the combined cycle. The power requirements for the ASU would be imported from the electric transmission grid as a discrete entity. In an effort to account for the difference between the net efficiency for HECA and the other projects listed in **Efficiency Table 2** (ranging from 36.4 to 38.5 percent), the net efficiency for HECA was calculated without the 109 MW ASU power load, yielding a 22.8 percent efficiency at LHV and a total auxiliary load ratio of 0.34. See **Efficiency Table 2**. When accounting for the ASU load in calculating the project's efficiency, the overall efficiency drops considerably below 22.8 percent, to approximately 13.5 percent.

[13] Comparison among IGCC systems with different gasifiers and carbon capture and sequestion: "Caost and Performanc Baseline for Fossil Energy Plants. Vol. I: Bituminous Coal and Natural Gas to Electricity. Revision 2, November 2010, National Energy Technology Labortory (NETL), Department of Energy, DOE/NETL-2010/1397.

Qualitative Considerations

In addition to providing a source of electricity, HECA would be designed to address additional project goals, whose efficiency measurement is ancillary factor to the commercial-scale demonstration of an IGCC facility. A compendium of some of these goals and their implementation methods are listed in the following **Efficiency Table 3**.

Efficiency Table 3
HECA Project Goals and Methods

GOAL	METHOD
• Diversify Fuel Source.	• 75 percent coal from New Mexico • 25 percent petcoke from California refineries
• Reduce carbon emissions to or beyond natural gas fuel levels.	• Chemical isolation of CO_2 for EOR and pastillation manufacturing.
• Utilize natural gas, which is a relatively clean, inexpensive and readily available fuel.	• Provide a reliable back-up fuel for unplanned outages • Improve plant availability during planned maintenance • Provide a reliable pilot fuel for start-up of the fuel gasification system
• Provide a useful product for local agricultural use.	• Manufacturing and processing of nitrogen-based products for crop fertilization

Although, the efficiency of HECA would be at a considerable disadvantage to the other projects listed in **Efficiency Table 2**, staff concurs with the applicant that the combined functions of processing the coal and petroleum coke feedstocks into a low-carbon/hydrogen-rich fuel gas, transmitting CO_2 for use in an EOR process, and utilizing the onsite generation of nitrogen for the production and manufacture of agricultural products should be taken into consideration when evaluating the project's efficiency impacts. Thus, although the project would demonstrate a low efficiency, the above mentioned benefits might be a reasonable tradeoff between the loss in efficiency and the potential environmental and commercial benefits offered by HECA.

Efficiency of Alternatives to the Project

Alternative Generating Technologies

Alternative generating technologies for the HECA project are considered in the AFC (HECA 2012a, AFC § 6.5). Nuclear, geothermal, biomass, wind, and solar power are not suitable to meet project objectives. Solar is not dispatchable, so is incapable of producing the ancillary services needed. Wind energy is not always available at the project area. Geothermal is not available at the HECA project site, and biomass may present problems with availability.

The overall thermal efficiency of HECA would be lower than the other projects listed in **Efficiency Table 2** due to HECA's high auxiliary loads, but the combined functions of processing the coal and petroleum coke feedstocks into a low-carbon/hydrogen-rich fuel gas, transmitting CO_2 for use in an EOR process, and utilizing the onsite generation of nitrogen for the production and manufacture of agricultural products might be a reasonable tradeoff between the loss in efficiency and the potential environmental and commercial benefits offered by HECA.

Mitsubishi MHI-501 GAC

The Mitsubishi MHI-501GAC machine has been in development and operation since 1997.[14] A full scale 250 MW demonstration facility employing the G Series model of this machine was brought up to full power in Nakaso, Japan in 2007 and has been operational since. The applicant would employ a one-on-one combined cycle plant using an MHI-501 GAC CTG coupled with a HRSG and an STG (HECA 2012a, AFC § 2.3, Table 2-14). The MHI-501GAC gas turbine represents a competitive and industry-proven machine, nominally rated at 404 MW and 59.2 percent efficiency LHV at ISO[15] conditions (GTW 2012).

Alternatives to the MHI-501GAC Combined Cycle Train

Staff compares in **Efficiency Table 4** alternative machines' ISO ratings as a common baseline, since project-specific ratings are not available for the alternative machines. Alternative machines that can meet the project's objectives are the GE 107FA combined cycle train with the 7FA frame CTG and the Siemens SCC-800H1S train, which are heavy duty 60 Hz gas turbine engines combined with a heat recovery steam generator with duct reheat.

The GE 107FA combined cycle system using a 7F frame in a one-on-one configuration is rated for 323 MW and 57.7 percent efficiency LHV (GTW 2012)

The Siemens SCC-800H1S combined cycle system utilizing an SGT6-800H CTG yields a nominal rating of 410 MW at 60.0 percent efficiency LHV at ISO conditions (GTW 2012).

Efficiency Table 4
Combined Cycle Comparison (Natural Gas Fuel)

Machine	Generating Capacity (MW)	ISO Efficiency (LHV)
Mitsubishi MPCP1 1 X M-501GAC	**404**[16]	**59.2 percent**
GE 107FA 1 X 7FA.05	323	57.7 percent
Siemens SCC-800H1S 1 X SGT6-800H	410	60.0 percent

While the Siemens power train enjoys a slight advantage in fuel efficiency over the applicant-selected power train, any differences among the three in actual operating efficiency would be relatively insignificant. Other factors such as generating capacity

[14] Modern Power Systems, May 1997, Vol. 17 Issue 5, pp. 31-334

[15] International Standards Organization (ISO) standard conditions are 15°C (59°F), 60 percent relative humidity, and one atmosphere of pressure (equivalent to sea level).

[16] ISO rated Net Plant Output: 2012 Gas Turbine World (GTW) Handbook, pg. 89.

and commercial availability are some of the factors considered in selecting the turbine model.

CUMULATIVE IMPACTS

No nearby projects have been identified that could potentially combine with HECA to create cumulative impacts on natural gas resources. Note that fuel-grade petcoke would be available from existing refineries in Southern California and plant demand would consume about 7 percent of the existing petcoke production within California (HECA 20 12a, §§ 2.1.11.2, 2.1.11.3); this would not likely create a significant adverse impact on the other petcoke customers. Also, there is abundant supply of coal in the country; the coal resources stretch from Montana to New Mexico in the west and from West Virginia to Pennsylvania in the east. Finally the PG&E natural gas supply system draws from extensive supplies originating in the Rocky Mountains, in the southwest, and in Canada.

Staff believes the project's fuel system is adequate to supply the HECA project without adversely impacting its other customers.

NOTEWORTHY PUBLIC BENEFITS

The applicant proposes to provide flexible baseline and intermediate electric power supply that provides a platform for support of ammonia products manufacture, transmission of compressed carbon dioxide for enhanced oil recovery and sequestration of a greenhouse gas, and gasification of its own primary fuel source.

DOE'S FINDINGS REGARDING DIRECT AND INDIRECT IMPACTS OF THE NO-ACTION ALTERNATIVE

Under the No-Action Alternative, DOE would not provide financial assistance to the applicant for HECA. The applicant could still elect to construct and operate its project in the absence of financial assistance from DOE, but DOE believes this is unlikely. For the purposes of analysis in the PSA/DEIS, DOE assumes the project would not be constructed under the No-Action Alternative. Accordingly, the No-Action Alternative would have no impacts associated with this resource area.

CONCLUSIONS

Please note that for the project's rated power capacity, staff uses 405 MW in this section of the PSA/DEIS despite the 431 MW capacity rating used elsewhere in the PSA/DEIS. No information on the overall project heat rate and breakdown of auxiliary loads, based on the 431 MW figure, is available to staff at this point. Staff will need to prepare the FSA based on a corrected MW figure.

Based on the 405 MW figure, the combined cycle component of the project would generate a maximum net output of 158 MW using its primary fuel of hydrogen rich syngas produced from gasified coal and petroleum coke. The coal/coke/syngas fuel cycle would produce a net fuel efficiency of 22.8 percent (13.5 percent with the ASU power requirement included) at lower heating value (LHV). In backup mode, the combined cycle plant (without the gasifier) would produce a net output of 300 MW using its secondary fuel of 100 percent natural gas with a net 50.3 percent efficiency at LHV at maximum full load and annual design ambient conditions[17].

While the project would internally consume substantial amounts of energy, it would still produce electricity in a reasonably efficient manner while meeting the project objectives of demonstrating the viability of carbon capture and sequestration and the production of fertilizer products. The combined functions of processing the coal and petroleum coke feedstocks into a low-carbon/hydrogen-rich fuel gas, transmitting CO_2 for use in an EOR process, and utilizing the onsite generation of nitrogen for the production and manufacture of agricultural products should be taken into consideration when evaluating the project's efficiency impacts.

The project would not create significant adverse effects on energy supplies or resources, would not require additional sources of energy supply, and would not consume energy in a wasteful or inefficient manner. No energy standards apply to the project. Staff therefore concludes that the project would present no significant adverse impacts upon energy resources. No cumulative impacts on energy resources are likely.

OUTSTANDING INFORMATION REQUIRED FOR COMPLETION OF THE FSA/FEIS

1. Reconciliation of the 405 MW gross power generation originally submitted in the AFC and the 431 MW power level currently under discussion elsewhere in this document;
2. Update of the mass and energy balance for the *entire* project boundary that uses *all* contemporaneous conditions, including the enhanced oil recovery (EOR) field, air separation (ASU), and the introduction of calcium carbonate to the feedstock blend, based on the 431 MW rating.
3. Identification and description of the major power block components, including the gasifier, based on the 431 MW rating.

PROPOSED CONDITIONS OF CERTIFICATION

No conditions of certification are proposed.

REFERENCES

GTW 2012 – Gas Turbine World. *Gas Turbine World 2012 Performance Specs*, 29th Edition, pp. 87, 89, 92. Published 2012.

HECA 2012a – Hydrogen Energy California LLC / Latham and Watkins/M. Carroll (tn 65049). Application for Certification, Volumes 1, 2 & 3, dated May 3, 2012. Submitted to CEC/Docket Unit on May 15, 2012 (tn 65213).

[17] At site temperature of 97°F with 20 percent humidity (HECA 2012a, AFC Table 2-2).

POWER PLANT RELIABILITY

Edward Brady

SUMMARY OF CONCLUSIONS

Hydrogen Energy California LLC, the applicant, predicts an equivalent power block availability factor of at least 91.3 percent, which staff believes would be possible upon the successful completion of the requisite one-year pilot operation. The applicant has not yet: 1) demonstrated adequate reliability of the project's industrial water supply and 2) assigned availability to the gasification system and ancillary systems upon which the power block is dependent. Pending the determination of the adequacy of the project's industrial water supply and completion of analysis to determine the reliability of the gasification system, staff cannot conclude that the Hydrogen Energy California Project (HECA) would be built and operated in a manner consistent with industry norms for reliable operation. No conditions of certification are currently proposed.

INTRODUCTION

In this analysis, California Energy Commission (Energy Commission) staff (staff) addresses the reliability issues of the project to determine if the power plant would likely be built in accordance with typical industry norms for reliability of power generation. Staff uses this level of reliability as a benchmark because it ensures that the resulting project would likely not degrade the overall reliability of the electric system it serves (see "Setting" below).

The scope of this power plant reliability analysis covers:

- equipment availability;
- plant maintainability;
- fuel and water availability; and
- power plant reliability in relation to natural hazards.

Staff examined the project design criteria to determine if the project would be built in accordance with typical industry norms for reliability of power generation. While the applicant predicted an equivalent availability factor of at least 91.3 percent for HECA (see below), staff uses typical industry norms as a benchmark, rather than the applicant's projection, to evaluate the project's reliability.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

No federal, state, or local/county laws, ordinances, regulations, and standards (LORS) apply to the reliability of this project.

SETTING

In the restructured competitive electric power industry, the responsibility for maintaining system reliability falls largely to the state's control area operators, such as the California

Independent System Operator (California ISO), that purchase, dispatch, and sell electric power throughout the state. Determining how the California ISO and other control area operators would ensure system reliability has been an ongoing effort. Protocols that allow sufficient reliability to be maintained under the competitive market system have been developed and put in place. “Must-run” power purchase agreements and “participating generator” agreements are two mechanisms that have been employed to ensure an adequate supply of reliable power.

The California ISO’s mechanisms to ensure adequate power plant reliability apparently were devised under the assumption that the individual power plants that compete to sell power into the system will each exhibit a level of reliability similar to that of power plants of past decades. However, there has been valid cause to believe that, under free market competition, financial pressures on power plant owners to minimize capital outlays and maintenance expenditures may act to reduce the reliability of many power plants, both existing and newly constructed. It is possible that, if significant numbers of power plants were to exhibit individual reliability sufficiently lower than this historical level, the assumptions used by California ISO to ensure system reliability would prove invalid, with potentially disappointing results. Accordingly, staff has recommended that power plant owners continue to build and operate their projects to the level of reliability to which all in the industry are accustomed.

The applicant proposes to operate a 405 to 431 megawatt (MW) (nominal gross), Integrated Gasification Combined Cycle (IGCC) electric power plant as part of a manufacturing complex that would include conversion of coal and petroleum coke (petcoke) feedstock into fuel (syngas), fertilizer, and delivery of carbon dioxide (CO_2) gas to the Occidental Elk Hill Incorporated (OEHI) processing facility for use in enhanced oil recovery (EOR) and sequestration (HECA 2012a, AFC § 2.1). The power plant portion of the project is expected to achieve an availability factor of at least 91.3 percent (HECA 2012, Response to Data Request A-90, November 2012). From the information provided from the applicant, staff calculated the net capacity factor (NCF) at 83.1 percent[1].assessment of impacts.

ASSESSMENT OF IMPACTS

METHOD FOR DETERMINING RELIABILITY

The Energy Commission must make findings as to the manner in which the project would to be designed, sited, and operated to ensure safe and reliable operation (Title 20, CCR §1752[c]). Staff takes the approach that a project is acceptable if it does not degrade the reliability of the utility system to which it is connected. This is likely the case if the project exhibits reliability at least equal to that of other power plants on that system.

[1] Appendix A “Definitions” and Appendix B “Equations”, 2007-2011 General Availability Report (GAR), North American Electric Reliability Corporation (NERC), AFC 2012a, Table 2-10 “Representative Heat and Material Balances”. Based on 16-hour per operation day at net maximum power production, 8-hours per day and maximum ammonia production, 351 hours planned outage and start-up, 91.3 percent availability factor (AF).

The availability factor for a power plant is the percentage of the time that it is available to generate power; both planned and unplanned outages subtracted from its availability. Measures of power plant reliability are based on the plant's actual ability to generate power when it is considered available and are based on starting failures and unplanned or forced outages. For practical purposes, reliability can be considered a combination of these two industry measures, making a reliable power plant one that is available when called upon to operate. Power plant systems must be able to operate for extended periods without shutting down for maintenance or repairs. Achieving this reliability is accomplished by ensuring adequate levels of equipment availability, plant maintainability with scheduled maintenance outages, fuel and water availability, and resistance to natural hazards. Staff examines these factors for the project and compares them to industry norms. If they compare favorably, staff can conclude that HECA would be as reliable as other power plants on the electric system and will therefore not degrade system reliability (see below for analysis).

EQUIPMENT AVAILABILITY

HECA would be composed of functional blocks that define discrete functions. Where a conventional combined cycle constitutes a single block, an IGCC is comprised of multiple functions organized into individual blocks:

- Solid Fuel Handling Block,
- Air Separation Unit Block,
- Gasification Block,
- Power Block, and
- Manufacturing Block.

The solid fuel handling block provides for delivery, storage, conveyance and preparation of the coal and petcoke feedstocks. The air separation unit (ASU) provides for the distillation of air into nitrogen and oxygen. The gasification system provides for the conversion of feedstock into syngas hydrogen fuel, which includes gasification, acid gas removal (AGR), solids waste handling, and carbon dioxide capture and sequestration (CCS). The power block is composed of the combustion turbine generator (CTG), the heat recovery steam generator (HRSG), the steam turbine generator, and the electric power generator. Lastly, the manufacturing block provides for the processing and manufacture of various ammonia based fertilizer products.

The availability of each succeeding block is dependent on the reliability of each preceding block. Feedstock handling and the ASU feed into the gasification, which needs feedstock materials and oxygen from the ASU. The power block relies on the gasification system for fuel and an on-site source of ammonia from the ASU through the manufacturing complex. In turn, the manufacturing complex depends on nitrogen from the ASU and electricity from the power block.

Dependencies can be ameliorated by redundancies, back-up fuels, and operating strategies that demand stringent quality assurance practices and quality control for materials and equipment. Examples of these strategies include:

- Utilization of parallel components and control systems;
- Substitution of natural gas for primary hydrogen fuel;
- Substitution of site generated nitrogen and ammonia with off-site sources; and
- Maintenance of on-site raw fuel reserves.

The power block is dependent on the gasification block and other upstream feeders: solid fuel handling and the ASU. Dependency on the feedstock handling is relieved by maintaining on-site storage reserves and the assumption that it is a mature industrial process with relatively few untested system components. Dependency on the ammonia from the manufacturing process is relieved by the ability to purchase and deliver a substitute for on-site chemical processing. The ASU and gasification system, then, become the critically reliable upstream blocks to the power systems.

The availability factor of the power block is estimated by industry operating data called Generating Availability Data System (GADS), which is compiled by the North American Electric Reliability Corporation (NERC). NERC publishes annual statistics, including the metrics called availability factor (AF) and equivalent availability factor (EAF). The AF reflects the annual planned outages and the EAF includes unplanned as well as planned periods off line. For the NERC combined cycle gas data base, AF equals 89.09 percent. With unplanned outages factored in, the EAF equals 86.76 percent.[2]

The applicant has presented an EAF of 91.3 percent for the power block, which is based on the anticipated planned outages of two 1-week periods plus 15 hours of start-ups and shutdowns[3] totaling 351 hours. The applicant subsequently provided a detailed cold start sequence of 4 days duration. For two cold startups, the additional planned outage for these two events would be 192 hours, bringing the total planned outage to 543 hours or 91.3 percent EAF.[4] See **Reliability Table 1** below.

Reliability Table 1
Comparison to NERC/GADS Database

Description	Planned Outage (hrs)	Unplanned Outage (hrs)	Total Outage (hrs)	EAF
HECA CONDITIONS:				
Applicant's EAF: (1 – 0.913) x 8760			762	91.3%
Two Maintenance Outages: 2 x 7 x 24	336			
Ramping: 15-hour Allowance	15			
Two Cold Starts: 2 x 4 x 24	192			
Subtotal	543	219	762	91.3%
NERC GADS COMPARISON (NGCC):				
(AF – EAF): (0.8909-0.8676) x 8760 hrs	956	204	1160	86.76%

Natural Gas Combined Cycle (NGCC), General Availability System (GADS)

[2] NERC GADS 2007-2011 "Annual Unit Performance Statistics, Combined Cycle", All MW sizes dated 9/13/12.

[3] HECA 2012a, Response to CEC Nos. A1-A123 Data Requests for A90 and A91, pg. A90-1

[4] E-mail from Robert Middlemore/HECA to Edward Brady/CEC dated 2/26/13: HECA Cold Startup.

The applicant anticipates 219 unplanned outage hours annual and the NERC database reflects that the average unplanned hours would be 204. Staff would agree that a 91.3 percent EAF would be attainable for the operation of the HECA power block. Although the availability factor submitted by the applicant covers the power block, it does not address the reliability of the upstream processes upon which the power block depends. The balance of plant reliability, particularly the gasification system and ASU, needs to be evaluated in order to complete the picture of integrated plant reliability.

GASIFICATION AVAILABILITY

The gasification block and the ASU are critical elements in evaluating reliability of the power block. Common to IGCC systems, their availability is calculated separately from the power block availability. The performance and availability are important because the gasification block and ASU are critical to the performance of the power block.

Polk Power Station in Tampa, Florida is an IGCC commissioned in the mid-1990s. It has a combined cycle gross power output of 315 MW. The gasifier is a Texaco slurry fed, oxygen blown entrained gasifier similar to the MHI gasifier proposed for the HECA project. The gasifier required a 30-day planned outage every other year. Polk experienced two ASU incidents requiring two unplanned shutdowns. After two years of shakedown operation, the gasifier availability after reaching mature operation averaged 82.0 percent. Power block availability was approximately 90.2 percent,[5] providing a compound availability factor of 74 percent.

Wabash River Coal Gasification Repowering Project completed its demonstration period in 1999. It has a 262 MW combined cycle power block with an E-Gas (Conoco Philips) gasifier. The first year availability factor was 22 percent but progressively improved its performance up to 76.0 percent by the end of 1999. The power block availability averaged around 96.1 percent,[6] factoring to a combined plant availability of 73.0 percent.

The gasification train, the ASU, and the combined cycle power blocks for Polk and Wabash are similar to the HECA project. For the purpose of comparing HECA's availability factor to similar projects, staff assumes that the gasifier availability is independent from the CCS and the manufacturing block (Polk and Wabash do not have CCS or a manufacturing block). Under this assumption, the block availabilities for Polk and Wabash would roughly apply to HECA. Using the average of the availability factors for Polk Power and Wabash River, or 79.0 percent, the combined gasifier and power blocks for HECA would have an availability factor of 72.1 percent. See **Reliability Table 2** (**Comparison of Systems and Plant Availability**) for a comparison among the selected gasification plants and HECA.

Reliability Table 2 presents a combination of published and derived AFs, and assumes that the reliability of up-stream systems upon which the power block is dependent is reflected in the gasification block availability. There would be a one-year pilot operation for HECA, which would allow for a shakedown of various components. This would offer

[5] Final Technical Report (August, 2002) Tampa Electric Poll Power Station Integrated Gasification Combined Cycle Project.

[6] Final Technical Report (August, 2000) Wabash River Goal Gasification Repowering Project.

the opportunity to improve HECA's equivalent availability factor of 72.1 to perhaps a figure comparable to the NERC's.

Reliability Table 2[7]
Comparison of Systems and Plant Availability

Description	Gasification Block Availability	Power Block Availability	Combined Availability
HECA Kern County, California	79.0 %	91.3%	72.1 %
Polk Power Tampa FL	82.0 %	90.2 %	74.0 %
Wabash River W. TerreHaute, Indiana	76.0 %	96.1 %	73.0 %

For a discussion of the role of natural gas as a back-up and redundant fuel supply, refer to the **Fuel Availability** section below.

The HECA Gasifier

The HECA gasifier would be sized to handle 5,800 short tons of feedstock per day (stpd), producing a clean syngas with an energy content of 3,925 mmBtu HHV (3,326 mmBtu LHV). HECA would use a 2-stage entrained downflow gasifier. Ash in the combustor section would melt to form a slag layer on the gasifier membrane walls, "sliding" toward the bottom of the gasifier. This slag gets water quenched and removed to a waste hopper. The remaining combustor gases rise toward the reductor section. Additional dry-milled feedstock is mixed with the hot combustor gases. The resulting syngas exits the reductor section and is cooled as it passes through a steam generator. At this point, a cyclone separator collects the remaining char in the syngas and recycles it to the combustor section, mixing with new fuel to increase overall carbon conversion efficiency.

The MHI gasifier proposed for this project has been through the same kind of testing and operation as the MH-501 gas turbine. In the early 1980's Mitsubishi partnered with the Japanese government to develop a 2 ton per day gasifier, concluding the developmental testing with a 200 ton unit. In 2004, MHI constructed a demonstration plant in Nakaso, Japan, coupling a 1,700 ton gasifier with a 250 MW power facility. The plant commenced operation in 2007.

Equipment availability would further be ensured by use of appropriate quality assurance/quality control (QA/QC) programs during design, procurement, construction and operation of the plant and by providing for adequate maintenance and repair of the equipment and systems (discussed below).

Quality Control Program

The applicant describes a program of process safety design (HECA 2012a, AFC § 2.8), which is similar to the classic quality control program and typical of the industrial process and power industries. Equipment would be purchased from qualified suppliers

[7] NETL On-line Gasifipedia: Gasification Research and Development, "Increasing Availability".

based on technical and commercial evaluations. The project owner would perform receipt inspections, test components, and administer independent testing contracts. Staff expects implementation of this program to yield typical reliability of design and construction. To ensure such implementation, staff has proposed appropriate conditions of certification under the portion of this document entitled **Facility Design**.

PLANT MAINTAINABILITY

Equipment Redundancy and Equivalency

A generating facility called on to operate in base-load service for long periods of time must be capable of being maintained while operating. A typical approach for achieving this is to provide redundant examples of those pieces of equipment most likely to require service or repair. In the initial phases of start up and operation, the applicant plans to spend one year in off-line testing and cycle balancing of the production complex.[8]

The power block would consist of one CTG (combustion turbine generator), one HRSG (heat recovery steam generator), and a gasifier. Except for a temporary shutdown during the Fukushima tsunami event, the Mitsubishi M501 GAC CTG has been in continuous field operation at MHI facilities in Nakaso, Japan since its start-up in 2007.

Enhanced system features designed to improve plant reliability at HECA include:

- Natural gas auxiliary boiler sized to provide 150,000 pounds per hour of steam when steam is not available from the gasification block or the HRSG. (HECA 2012a, § 2.5.8).
- Maintenance of a minimum one month's inventory of feedstock products on site to minimize the risk of plant shutdown due to short-term interruption or delivery delays of feedstock products. The natural gas back-up serves multiple functions:
    - 100 percent fuel back-up for the hydrogen gas produced on-site.
    - Serve as a reliable fuel to stabilize and control the 4-day cold start-up.[9]
    - Fuel substitute while gasification system is off-line for planned maintenance.
- Applicant's plan to operate as a pilot plant for one year prior to availability commitment to California ISO.
- Direct CO_2 vent allowance of 504 hours in the event of a transmission pipe break or Enhanced Oil Recovery (EOR) service interruption.

Taking into account these considerations, upon the successful completion of the one-year pilot operation, HECA would very likely demonstrate a combined gasifier and power blocks availability factor of greater than 72.1 percent and perhaps to a figure that would be comparable to the NERC's figures.

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[8] HECA 2012a AFC, § 2.9-2, p. 2-74

[9] Discussion on start-up sequencing with Robert Middlemore/Fluor, confirmed by e-mail dated 2/26/13.

Maintenance Program

The applicant proposes to establish a preventive plant maintenance program typical of industry practice (HECA 2012a, AFC §§ 2.3.2.1, 2.9.2). Equipment manufacturers provide maintenance recommendations with their products; the applicant would base its maintenance program on these recommendations. The applicant has programmed two one-week planned shutdowns annually, twice the manufacturer's requirements and extended the system start-up period to one full year. Maintenance outages would be planned for periods of low electricity demand. In light of these plans, staff expects that the project would be adequately maintained to ensure acceptable reliability.

LINEAR SYSTEMS AVAILABILITY

For any power plant, the long-term availability of fuel and of water for cooling or process use is necessary to ensure reliability. The need for reliable sources of fuel and water is obvious; lacking long-term availability of either source, the service life of the plant may be curtailed, threatening the supply of power as well as the economic viability of the plant.

Fuel Availability

HECA will burn syngas refined on the plant site from coal and petcoke fuel stocks. There would be a minimum one month's inventory of feedstock products on site in case of interruption in availability of feedstock. As a means of providing redundant fuel supply, natural gas will be piped thirteen (13) miles to an existing Pacific Gas & Electric (PG&E) natural gas pipe line located north of the project site (HECA 2012a, AFC § 2.7.1.10).

PG&E's natural gas supply system represents a resource of considerable capacity and offers access to adequate supplies of gas from the Rocky Mountains, Canada, and the Southwest. PG&E will own, operate and maintain the gas pipeline. Maintenance of the natural gas pipeline will follow PG&E corporate policies and protocols.

The high reliability of the natural gas virtually elevates its role in HECA from a back-up to redundant fuel system. It has the capability of making the planned and unplanned outages that are not caused by power block failures to be completely transparent from the viewpoint of the power grid. The benefits of natural gas to selectively reduce outages that require repair or replacement of non-power block systems and components would be tied to the flexibility provided for in the power purchase agreement (PPA) under which HECA negotiates with an available utility provider.

Staff agrees with the applicant's prediction that there would be adequate fuel supply and pipeline capacity to meet the project's needs.

Water Supply Reliability

The project would use water for plant service needs, cooling system makeup, combustion turbine injection, combustion turbine evaporative cooling makeup, and secondary fire protection and other processes. This water would be supplied by Buena Vista Water Storage District (BVWSD) (HECA 2012a, AFC § 2.7.1.10) using brackish water from a well field and pipeline system, which would be owned by BVWSD. The process water pipeline route would run approximately 15 miles from Seventh Standard Road to the HECA site, along the existing BVWSD road on the northwest side of West Side Canal.

Under the present system design, the industrial water supply requirements for HECA would be 7416 acre-feet per year (afy) which would come from existing aquifers under the jurisdiction of BVWSD. Currently the water system modeling indicates that drawdown of some of the wells will have an effect on water quality. Staff cannot verify that the use of the proposed groundwater satisfies state and Energy Commission policies regarding the use and conservation of water resources (see the **Water Supply** section of this document). Since staff is relying on the applicant to consider or implement recommendations proposed in the **Water Supply** section of this document, staff will continue to consider this irresolution a significant impact until water system modeling could demonstrate otherwise.

Carbon Dioxide (CO_2) Pipeline and EOR Reliability

A CO_2 pipeline will be constructed to transfer the carbon dioxide produced by HECA to the Occidental Elk Hills Incorporated (OEHI) CO_2 processing facility for injection into deep underground hydrocarbon reservoirs for EOR (HECA 2012a, AFC § 2.7.1.10). The CO_2 pipelines will run three miles from the southwestern portion of the HECA project site, using horizontal directional drilling (HDD) to pass under the Outlet Canal, the Kern Valley Flood Control Chanel, and the California Aqueduct. From the south side of the aqueduct, the route extends southeast and south to the OEHI Processing Facility.

In the event that a pipeline break or an unplanned interruption of gas injection at the EOR field, an allowance has been made to atmospherically discharge CO_2 laden combustion gases from the CTG through the HRSG exhaust stack for an aggregate period of approximately 500 hours per year.[10] For this reason, temporary failure or downgrade of the carbon sequestration system is accommodated without interrupting electric power generation. See **Air Quality Table 5** for further description of the discharge air allowances.

POWER PLANT RELIABILITY IN RELATION TO NATURAL HAZARDS

Natural forces can threaten the reliable operation of a power plant. High winds, tsunamis (tidal waves), seiches (waves in inland bodies of water), and flooding would not likely represent a hazard for this project, but seismic shaking (earthquake) may present a credible threat to reliable operation.

Seismic Shaking

The HECA site and off-site linears (natural gas, water and CO_2 pipeline) are susceptible to ground shaking generated during earthquakes on nearby faults (HECA 2012a, AFC § 5.15.1.5). The site lies within the seismically active Southern California. Naturally occurring seismic events on the order of magnitude 6 and smaller, even if located in the

[10] Air quality analysis has been based on an annual allowance of 504 hours direct atmospheric discharge of carbon dioxide in the first year of pilot operation. Although the estimates for subsequent years are 120 hours for the life of the plant, the 504 hour allowance has been retained as the qualification basis.

immediate area of the field, should not cause significant damage to HECA or wells in the Elk Hills Oil Field (HECA 2012, AFC § 5.15.1). See “Faulting and Seismicity” portion of the **Geology and Paleontology** section of this document**.** Compliance with current seismic design LORS represents an upgrading of performance during seismic shaking compared to older facilities since these LORS have been continually upgraded. Because it would be built to the latest seismic design LORS, this project would likely perform at least as well as, and perhaps better than, existing plants in the electric power system. Staff has proposed conditions of certification to ensure this; see the section of this document entitled **Facility Design**. In light of the general historical performance of California power plants and the electrical system in seismic events, staff has no special concerns with the power plant’s functional reliability during earthquakes.

Flooding

The ground level elevation of the HECA site is at an elevation of approximately 188.5 feet above mean sea level (MSL). According to the Federal Emergency Management Agency (FEMA) Flood Insurance Rate Maps (FIRM), the site is not located in an area identified as having flood hazards or shallow groundwater (FEMA 2008; HECA 2012a, AFC § 5.14.1.3). According to Kern County General Plan Safety Element Fig. 14, the HECA site is not in an area identified as having flood hazards or shallow ground water (HECA 2012a, AFC § 5.15.1.5). The CO_2 pipeline extending to the south of the HECA site will cross a flood hazard zone associated with the Kern River Flood Control Canal. With proper plant design (ensured by adherence to the proposed **Facility Design** conditions of certification), staff believes there are no concerns with power plant functional reliability due to flooding. For further discussion, see **Soil and Water Resources** and **Geology and Paleontology**.

COMPARISON WITH EXISTING FACILITIES

Industry statistics for availability factors (as well as many other related reliability data) are kept by the North American Electric Reliability Corporation (NERC). NERC continually polls utility companies throughout the North American continent on project reliability data through its Generating Availability Data System (GADS) and periodically summarizes and publishes the statistics on the Internet [http://www.nerc.com]. NERC reports an equivalent availability factor of 86.7 percent as the generating unit average figure for the years 2007 through 2011 for natural gas-fired combined cycle systems (All MW sizes) (NERC 2012).

The model of gas turbine that would be employed in the HECA project, the M501GAC model, has been on the market for several years and can be expected to exhibit typically high availability. The G-series combustion gas turbine has been in full operational testing in Nakaso, Japan since 2007 and has reached the 5,000 hour milestone for continuous duty. In addition, MHI is building a 540 MW coal gasification facility with carbon capture in Queensland, Australia’s Zero Gen Project. Confident in the developmental testing, the owner/operator has bypassed the pilot phase of the project and proceeded directly to commercial-scale operation.

The applicant’s prediction of an annual availability factor of at least 91.3 percent for the CTG/HRSG power block alone (HECA 2012, Response to DR-90) appears reasonable, compared to the NERC figure for similar power blocks throughout North America (see above). But, the combined gasifer and power block availability factor of 72.1 percent seems too low to achieve 8,000 hours (91.3 percent) of operation. However, upon the successful completion of the one year pilot operation, 8,000 hours of power block operation may be possible. In light of the Mitsubishi's operating and testing plan prior to commercial offering, the one-on-one combined cycle facility proposed by the applicant can be expected to outperform the fleet of various (mostly older) gas turbines that make up the NERC statistics. The applicant has opted to run and test the HECA project for a full year before initiating commercial use. In addition, they have doubled the recommended planned maintenance outages from the amount recommended by Mitsubishi. Within this period of pilot operation, observation and testing would include:

- Performance monitoring of MHI's dry-bed entrainment gasifier at the selected feedstock blend.
- Refinement of cold-start procedures for ramping up to full power operation.
- Accumulation of commercial-level operating experience prior to commitment of availability to California ISO.
- Assessment of system characteristics when shifting daily between maximized ammonia plant operation and maximized electrical power generation.
- Verification of overall projected plant availability factors.

Taking into account the benefits, knowledge and experience garnered from the one-year pilot operation, the applicant's estimate of plant availability, therefore, appears reasonable. The stated procedures for assuring design, procurement, and construction of a reliable power plant appear to be in keeping with industry norms, and staff believes they are likely to yield an adequately reliable plant.

NOTEWORTHY PROJECT BENEFITS

The benefit of this project, as related to power plant reliability, should be that HECA not degrade the overall reliability of the electric system it serves. Staff cannot make a conclusion in this regard until it can determine the adequacy of the project's industrial water supply and the reliability of the gasification system to which the power block would depend on.

CONCLUSIONS

The staff's major focus is the reliability of the systems necessary to provide electric power to the grid. All of the systems, blocks and elements of HECA, whose function contribute to this function and purpose, constitute the areas of review. They are the power block and the gasification system, including the air separation unit.

The applicant has provided an availability factor of 91.3 percent, which only reflects the design and operational elements of the power block. The predicted availability factor for the combined gasifier and power blocks is 72.1 percent prior to the one-year pilot operation. HECA would have the opportunity to improve this availability factor to a greater than 72.1 percent figure, to perhaps a figure that would be comparable to the NERC's statistics. The countermanding conditions to this availability level are 1) the incorporation of natural gas as a readily available back up fuel; 2) the implementation of a one-year commissioning shakedown after construction is complete and before commercial operation commences; and 3) the study and development of Mitsubishi's IGCC (integrated generation /combined cycle) demonstration project that commenced in 2007 and includes analysis and review of CCS (carbon capture and sequestration).

Staff considers the issue of water supply pumping, which draws down some aquifers and affects water quality, has a potentially significant impact on the reliability of the facility's industrial water supply. Staff reserves an opinion on this impact until the applicant has the opportunity to undertake a more extensive modeling and review of the aquifers that are under consideration and potentially available for this project, and evaluate alternative water use efficiency technologies.

Pending the determination of the adequacy of the project's industrial water supply and completion of analysis to determine the reliability of the gasification systems, staff cannot conclude that the Hydrogen Energy California Project (HECA) would be built and operated in a manner consistent with industry norms for reliable operation. No conditions of certification are currently proposed.

OUTSTANDING INFORMATION REQUIRED FOR COMPLETION OF THE FSA/FEIS

The applicant has failed to assign an AF (availability factor) to the gasification system and ancillary systems upon which the power block is dependent. The applicant needs to assign this AF, demonstrate how it was derived, and explain how it affects the 91.3 percent AF assigned to the power block.

PROPOSED CONDITIONS OF CERTIFICATION

No conditions of certification are proposed.

REFERENCES

HECA 2012a – Hydrogen California LLC, 08-AFC-8A. Amended Application for Certification, Volumes 1, 2, and 3 dated May 02, 2012. Submitted to CEC/Docket Unit on May 02, 2012.

NERC (North American Electric Reliability Council). 2012. 2007–2011 Generating Availability Report.

TRANSMISSION SYSTEM ENGINEERING

Sudath Edirisuriya and Mark Hesters

SUMMARY OF CONCLUSIONS

The proposed Hydrogen Energy California Project (HECA) outlet lines and termination are acceptable and would comply with all applicable laws, ordinances, regulations, and standards (LORS). No additional new transmission facilities that would require a California Environmental Quality Act (CEQA) review other than those proposed by the applicant are needed for the interconnection of the HECA project.

- A new offsite breaker and-a-half, 230kV, 63kA PG&E switchyard and 2.8 miles long generator tie line would be required to interconnect the HECA project to the California ISO grid. The new switchyard would be constructed by PG&E and is considered part of the HECA project.
- The Transition Cluster Phase I Interconnection Study Report (Phase I Study) indicated that the project contributes to South of Vincent flow Area Deliverability constraints. The recommended mitigation of the voltage instability would require upgrades in the SCE Mesa 500kV system. These upgrades would be done within the fence line of the existing Mesa substation.
- The installation of a new fiber optic line from the HECA switching station to the Midway Substation may necessitate CEQA analysis. The proposed 8.5 mile long fiber optic line will be constructed within the PG&E right-of-way by using the existing 230kV Transmission towers.

The Transition Cluster Phase II Interconnection Study Report (Phase II Study) for the HECA is scheduled to be issued by early July, 2013. Staff expects to analyze the Phase II Study to determine the downstream distribution impacts and any required mitigation.

STAFF ANALYSIS

The Transmission System Engineering (TSE) analysis examines whether or not the facilities associated with the proposed interconnection conform to all applicable LORS required for safe and reliable electric power transmission. Additionally, under CEQA, the Energy Commission must conduct an environmental review of the “whole of the action,” which may include facilities not licensed by the Energy Commission (California Code of Regulations, title 14, §15378). Therefore, the Energy Commission must identify the system impacts and necessary new or modified transmission facilities downstream of the proposed interconnection that are required for interconnection and represent a “connected action”.

Commission staffs rely on the interconnecting authority for the analysis of impacts on the transmission grid as well as the identification and approval of required new or modified facilities downstream from the proposed interconnection required as mitigation measures. The proposed HECA would connect to the Pacific Gas and Electric (PG&E)

230kV transmission network and requires the Phase II Study analysis by PG&E and approval of the California Independent System Operator (California ISO).

PACIFIC GAS & ELECTRIC'S ROLE

PG&E is responsible for ensuring electric system reliability in the PG&E system for addition of the proposed generating plant. PG&E will provide the analysis and reports in the upcoming Phase II Study for its Group 5 projects, along with approval of the facilities and changes required in the PG&E system for addition of the proposed transmission modifications.

CALIFORNIA ISO'S ROLE

The California ISO is responsible for ensuring electric system reliability for all participating transmission owners and is also responsible for developing the standards necessary to achieve system reliability. The California ISO is responsible for completing the studies of the PG&E system to ensure adequacy of the proposed transmission interconnection. The California ISO will determine the reliability impacts of the proposed transmission modifications on the PG&E transmission system in accordance with all applicable reliability criteria. According to the California ISO Tariff, the California ISO will determine the "Need" for transmission additions or upgrades downstream from the interconnection point to ensure reliability of the transmission grid. The California ISO will, therefore, review the Phase I Study performed by PG&E and/or any third party and will provide their analysis, conclusions and recommendations. Upon completion of the PG&E Phase II Study based on the expected September-2017 commercial operation date (COD), or current COD, the California ISO would execute a Large Generator Interconnection Agreement (LGIA) with the project owner. If necessary, the California ISO may provide written and verbal testimony on their findings at the Energy Commission hearings.

Laws, Ordinances, Regulations and Standards

- North American Electric Reliability Council (NERC) Planning Standards provide policies, standards, principles and guides to assure the adequacy and security of the electric transmission system. With regard to power flow and stability simulations, these planning standards are similar to WECC criteria for Transmission System Contingency Performance. The NERC planning standards provide for acceptable system performance under normal and contingency conditions. The NERC planning standards apply not only to interconnected system operation but also to individual service areas (NERC 1998).
- Western Electric Coordinating Council (WECC) Reliability Criteria provide the performance standards used in assessing the reliability of the interconnected system. These reliability criteria require the continuity of service to loads as the first priority and preservation of interconnected operation as a secondary priority. The WECC Reliability Criteria include the Reliability Criteria for Transmission System Planning, Power Supply Design Criteria, and Minimum Operating Reliability Criteria. Analysis of the WECC system is based to a large degree on WECC Section 4 "Criteria for Transmission System Contingency Performance" which requires that the results of power flow and stability simulations verify established performance levels.

Performance levels are defined by specifying the allowable variations in voltage, frequency and loading that may occur on systems other than the one in which a disturbance originated. Levels of performance range from no significant adverse effect outside a system area during a minor disturbance (loss of load or facility loading outside emergency limits) to a performance level that only seeks to prevent system cascading and the subsequent blackout of islanded areas. While controlled loss of generation, load, or system separation is permitted in extreme circumstances, their uncontrolled loss is not permitted (WECC 1998).

- California Public Utilities Commission (CPUC) General Order 95 (GO-95), "Rules for Overhead Electric Line Construction," formulates uniform requirements for construction of overhead lines. Compliance with this order ensures adequate service and safety to persons engaged in the construction, maintenance, operation, or use of overhead electric lines and to the public in general.
- California Public Utilities Commission (CPUC) General Order 128 (GO-128), "Rules for Underground Electric Line Construction," formulates uniform requirements for construction of underground lines. Compliance with this order ensures adequate service and safety to persons engaged in the construction, maintenance, operation, or use of underground electric lines and to the public in general.
- National Electric Safety Code 1999 provides electrical requirements for overhead and underground electric line construction and design.
- California ISO's Reliability Criteria also provide policies, standards, principles, and guides to assure the adequacy and security of the electric transmission system. With regard to power flow and stability simulations, these planning standards are similar to WECC Criteria for Transmission System Contingency Performance and the NERC Planning Standards. The California ISO Reliability Criteria incorporate the WECC Criteria and NERC Planning Standards. However, the California ISO Reliability Criteria also provide some additional requirements that are not found in the WECC Criteria or the NERC Planning Standards. The California ISO Reliability Criteria apply to all existing and proposed facilities interconnecting to the California ISO controlled grid. It also applies when there are any impacts to the California ISO grid due to facilities interconnecting to adjacent controlled grids not operated by the California ISO.

PROJECT DESCRIPTION

The applicant has proposed to interconnect the 300 MW (net) Hydrogen Energy California Project (HECA project) to a proposed PG&E 230kV switching station via 230kV single circuit. The 230kV switching station would be constructed solely for the interconnection of the HECA project. The HECA project would consist of one hydrogen-fueled gas/steam turbine single shaft generator (GTG-STG rated at 405 MW). The generator auxiliary load would be 105 MW resulting in a maximum net output of 300 MW at an 90 percent power factor. The GTG-STG generator would be connected to the low side of its generator step-up transformer through a gas insulated (SF6) breaker and a disconnect switch. The step-up transformer for the GTG-STG unit would be rated at 21/230 kV and 270/360/450 MVA and the high side of the step up transformer would be connected to the HECA project switching station via 2000 Amps disconnect switch and a breaker.

Generator Interconnection facilities:

The HECA project onsite switching station consist of PG&E revenue metering equipment and other switching gear to allow delivery of project output to the proposed PG&E 230kV switching station. The HECA project would interconnect to the PG&E 230kV switching station via a 230kV, single circuit (generator-tie-line) at the Olean Avenue and Elk Valley road intersection. The generator-tie line route leaves the project site east to Tupman road, continuing north to near Adohr road, then east to the new PG&E switching station. The generator tie line would be approximately 2.8 miles long, using 15 off site and 11 onsite single shaft galvanized 230kV tubular-steel structures. The proposed single three phase circuit will use 1272 kcmil ACSR conductor which is capable of carrying the full output of the project. The switching station would be built with 230kV bus work to facilitate eight circuit breakers, three bays with breaker and half configuration with six line positions. The line positions would be used to terminate the generator tie line of the HECA, a PG&E feeder to an ASU unit and four for the loop in of the Midway –Wheeler Ridge double circuit 230kV line (one position for each circuit as it enters and one as it leaves the switching station). Looping in the Midway - Wheeler Ridge double circuit line to the proposed switchyard would require the removal of two existing 230kV towers and the installation of two new dead end structures.

The applicant proposes to use the 230kV structures to support another 230kV single circuit which would enable them to import power into the onsite Air Separation Unit (ASU) from the PG&E grid. The proposed 100MW ASU unit is part of the project, but consumes power directly from the PG&E grid. (HECA 2012b, sections 2.1.12.1, 2.7.1.10 and Figures 2- 12 and 2-21 to 2-27)

Telecommunication Interconnection facilities:

In order to insure the reliability of the transmission grid after the interconnection of the HECA project, the installation of a new fiber optic line from the interconnection switching station to the Midway Substation would be required. The proposed 8.5 mile long fiber optic line will be constructed within the PG&E right-of-way using the existing 230kV transmission towers.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

For the interconnection of a proposed generating unit or transmission facility to the grid, the interconnecting utility and the control area operator are responsible for ensuring grid reliability. For the HECA, PG&E and the California ISO are responsible for ensuring grid reliability.

The California ISO’s generator interconnection study process is in transition from a serial process to an interconnection window cluster study process. The HECA was studied under the cluster process and the transmission reliability impacts of the proposed project are studied in the Phase I and Phase II Studies. The Phase I Study is similar to the former System Impact Study except it is now performed for a group of projects in the same geographical area of a utility that apply for interconnection in the same request window. The Phase II Study is performed after generators in each cluster meet specific milestones required to stay in the generator interconnection queue. The Phase II Study is then performed based on the number of generators left in each cluster.

The Phase I Study for projects in the transition cluster was conducted to determine the preferred and alternative generator interconnection methods and to identify any mitigation measures required to ensure system conformance with utility reliability criteria, NERC planning standards, WECC reliability criteria, and California ISO reliability criteria. Staff relies on the studies and any review conducted by the responsible agencies to determine the effect of the projects on the transmission grid and to identify any necessary downstream facilities or indirect project impacts required to bring the transmission network into compliance with applicable reliability standards (NERC2006, WECC 2006, California ISO 2002a, 2007a & 2009a).

The Phase I Study analyzes the grid with and without the generator or generators in a cluster under conditions specified in the planning standards and reliability criteria. The standards and criteria define the assumptions used in the study and establish the thresholds by which grid reliability is determined. The studies must analyze the impact of the projects for their proposed first year(s) of operation and thus are based on a forecast of loads, generation and transmission. Load forecasts are developed by the interconnected utility, which would be PG&E in this case. Generation and transmission forecasts are based on the interconnection queue. The studies are focused on thermal overloads, voltage deviations, system stability (excessive oscillations in generators and transmission system, voltage collapse, loss of loads or cascading outages), short circuit duties and substation evaluation

Under the new California ISO LGIP, generators are able to choose between either “full capacity” or “energy only” depending on whether or not the generator wants to have the right to generate energy 24-hours per day. A generator that chooses the full capacity option will be required to pay for transmission network upgrades that are needed to allow the generator to operate under virtually any system conditions and as such could sign contracts that allowed them to provide capacity to utilities. Energy only generators would not pay for network transmission upgrades, and essentially would have access to as available transmission capacity, and would likely not be able to sign capacity contracts.

If the studies show that the interconnection of the project or cluster of projects causes the grid to be out of compliance with reliability standards, the study will then identify mitigation alternatives or ways in which the grid could be brought into compliance with reliability standards. If the interconnecting utility determines that the only feasible mitigation includes transmission modifications or additions which require CEQA review as part of the “whole of the action,” the Energy Commission must analyze those modifications or additions according to CEQA requirements. Where the Phase I Study identifies transmission modifications required for the reliable interconnection of a cluster of generators, staff will analyze the proposed generating project’s impact on individual reliability criteria violations to determine whether or not the identified mitigation measures are a reasonably foreseeable consequence of the proposed project.

SCOPE OF INTERCONNECTION STUDY:

The queue cluster 5 (QC5) phase one interconnection study was performed by PG&E in coordination with California ISO to identify the transmission impacts caused by the cluster 5 projects on PG&E's 115/230/500-kV system. The study included 23 cluster 5 generation projects; four were PG&E Wholesale Distribution Tariff generation projects that are seeking full capacity deliverability status. Three general groups were formed based on the electrical impacts among the generation projects; Fresno, Kern and North Groups.

The Kern Group study report provides the impacts caused by the addition of QC5 phase one projects requesting interconnection in the Kern Group. Nine generation projects totaling a maximum output of 522.5 MW were included in the QC5 phase 1 Kern group study. In addition, the study included a number of transmission upgrades needed to support load growth and queued ahead generation projects in PG&E's Kern group area that were modeled in order to determine if additional facilities would be needed to support the QC5 Kern group. The base cases were developed to represent stressed scenarios of loading and generation conditions for the study group area, based on a 2016 load forecast. The power flow analyses were performed using PG&E's 2016 Summer Peak and Summer off Peak Full Loop Power Flow cases. The power flow cases modeled all California ISO approved PG&E transmission projects, regardless of their proposed in-service date. These base cases included all California ISO approved higher queued serial group, transition cluster QC5 generation projects with associated network upgrades and Special Protection Systems. The study included Deliverability Assessment, Reliability Network Assessment, Power Flow Analysis, Short Circuit Analysis, Reactive Power Deficiency Analysis and Transient and Post Transient Stability Analysis. The detailed study assumptions are described in the study.

TRANSITION CLUSTER STUDY RESULTS:

Detailed results of the Transitional Cluster Study are below. Where potential overloads are identified, mitigation is proposed that would eliminate the potential impact to reliability. Based on the information in the Phase I study, the HECA appears to be responsible for few of the impacts that are identified for the cluster, due to the HECA interconnection at the proposed switching station. Staff expects that the applicant will submit the complete phase II study with appendices to finalize the mitigation measures in time for it to be included in the the Final Staff Assessment (FSA).

Deliverability Assessment study results:

The study indicated that the project contributes to the South of Vincent flow deliverability constraints. The South of Vincent flow limit has been identified as driven by the voltage instability following an outage of the Lugo- Vincent 500kV number 1 and 2 circuits. It is an area deliverability constraint which impacts deliverability of generation north of Vincent. Therefore to improve the South of Vincent transfer capability network upgrades would be required.

> Mitigation: Upgrades to Southern California Edison's (SCE) Mesa area 500kV system and distribution upgrades to support the Mesa area 500kV system.

Reliability Assessment study results:

The reliability analysis was performed on power flow cases that include all energy-only and full capacity projects dispatched to maximum values for each power flow case. Energy-only projects dispatched to maximum values for each power flow case. Energy-Only projects often do not have transmission capacity upgrades and rely upon California ISO Congestion Management to manage thermal loading in the transmission system.

> The reliability analysis did not indicate that the HECA project contributes criteria violations that result in the need for downstream reliability network upgrades.

Local Delivery Network study results:

The project did not cause any thermal overloads or instability of the local delivery network.

> Therefore, HECA project is not responsible for any local delivery network upgrades.

Area Delivery Network study results:

The study indicated that the project contributes to the South of Vincent flow Area deliverability constrains. To improve the South of Vincent transfer capability the proposed area delivery network upgrades would be required.

> Mitigation: The recommended mitigation for this voltage instability are SCE Mesa area 500kV system upgrades and SCE Distribution upgrades to support the Mesa area 500kV system.

Steady State and Post-Transient Voltage Stability Assessment study results:

Thermal overloads occurring after modeling all delivery network upgrades are mitigated by congestion management in both pre- and post-project cases. There were no voltage or reactive power deficiencies identified in the reliability analysis for the Kern group.

Transient Stability Analysis results:

Stable and adequately damped transient stability performances were achieved following all of the outages simulated using both the pre-and post-cluster summer peak full loop base cases. The power flow studies of N-1 and N-2 contingencies showed that the project would not cause voltage drops of 5 percent or more from the pre-project levels or cause the PG&E system to fail to meet applicable voltage criteria. No transient frequency criteria violations were observed for all the contingencies simulated. The transient stability study projected that the transmission system's performance relative to the applicable reliability guidelines would not be adversely affected by the Phase I projects due to selected disturbances. A worst condition analysis for the outages did not result in any voltage or frequency violations by the project. Therefore no additional network upgrades are required due to the project.

Short Circuit Study Results:

Short circuit studies were performed to determine the degree to which the addition of Phase I projects would increase fault duties at PG&E's substations, adjacent utility substations, and the other 115 kV, 230 kV and 500 kV busses within the study area. For the buses at which faults were simulated, the maximum three-phase and single-line-to-ground fault currents, both with and without the project, and information on the breaker duties at each location, are summarized in Appendix H, short circuit study results, of the Phase I study report. The short circuit duty assessment found that the addition of Cluster 5 projects in the PG&E Kern group did not result any short circuit duty violations on the system.

COMPLIANCE WITH LORS

The Phase I study indicates that the project interconnection would comply with NERC/WECC planning standards and California ISO reliability criteria. The applicant would design, build and operate the proposed 230 kV HECA switchyard and overhead generator transmission lines. The proposed 230kV PG&E substation would be designed and built by the applicant, but would be turned over to PG&E for operation. Staff concludes that assuming the proposed conditions of certification are met; the project would meet the requirements and standards of all applicable LORS.

DOE'S FINDINGS REGARDING DIRECT AND INDIRECT IMPACTS OF THE NO-ACTION ALTERNATIVE

Under the No-Action Alternative, DOE would not provide financial assistance to the applicant for HECA. The applicant could still elect to construct and operate its project in the absence of financial assistance from DOE, but DOE believes this is unlikely. For the purposes of analysis in the PSA/DEIS, DOE assumes the project would not be constructed under the No-Action Alternative. Accordingly, the No-Action Alternative would have no impacts associated with this resource area.

CONCLUSIONS

The proposed Hydrogen Energy California Project outlet lines and termination are acceptable and would comply with all applicable laws, ordinances, regulations, and standards (LORS). No additional new transmission facilities that would require a CEQA review other than those proposed by the applicant are needed for the interconnection of the HECA project.

- A new offsite breaker and-a-half, 230kV, 63kA switchyard and 2.8 mile long generator tie line would be required to interconnect the HECA project to the California ISO grid. The new switchyard would be constructed by PG&E and is considered part of the HECA project.
- The Transition Cluster Phase I Interconnection Study indicated that the project would contribute to South of Vincent flow Area Deliverability constraints. The recommended mitigation of the voltage instability would require SCE Mesa area 500kV system upgrades. These upgrades would be done within the existing Mesa substation and would not trigger CEQA.
- The installation of a new fiber optic line from the HECA switching station to the Midway Substation may necessitate CEQA analysis. The proposed 8.5 mile long

fiber optic line will be constructed within the PG&E right-of-way by using existing 230kV Transmission towers.

RECOMMENDATIONS

If the Commission approves the project, staff recommends the following conditions of certification to insure system reliability and conformance with LORS.

CONDITIONS OF CERTIFICATION FOR TSE

TSE-1 The project owner shall furnish to the CPM and to the CBO a schedule of transmission facility design submittals, a Master Drawing List, a Master Specifications List, and a Major Equipment and Structure List. The schedule shall contain a description and list of proposed submittal packages for design, calculations, and specifications for major structures and equipment. To facilitate audits by Energy Commission staff, the project owner shall provide designated packages to the CPM when requested.

<u>Verification:</u> At least 60 days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of transmission facility construction, the project owner shall submit the schedule, a Master Drawing List, and a Master Specifications List to the CBO and to the CPM. The schedule shall contain a description and list of proposed submittal packages for design, calculations, and specifications for major structures and equipment (see a list of major equipment in **Table 1: Major Equipment List** below). Additions and deletions shall be made to the table only with CPM and CBO approval. The project owner shall provide schedule updates in the Monthly Compliance Report (MCR).

Table 1: Major Equipment List

Breakers
Step-up Transformer
Switchyard
Busses
Surge Arrestors
Disconnects
Take off facilities
Electrical Control Building
Switchyard Control Building
Transmission Pole/Tower
Grounding System

TSE-2 Prior to the start of transmission facility construction, the project owner shall assign an electrical engineer and at least one of each of the following to the project: A) a civil engineer; B) a geotechnical engineer or a civil engineer experienced and knowledgeable in the practice of soils engineering; C) a design engineer, who is either a structural engineer or a civil engineer fully competent and proficient in the design of power plant structures and equipment supports; or D) a mechanical engineer. (Business and Professions Code Sections 6704 et seq. require state registration to practice as a civil engineer or structural engineer in California.)

The tasks performed by the civil, mechanical, electrical or design engineers may be divided between two or more engineers, as long as each engineer is responsible for a particular segment of the project (e.g., proposed earthwork, civil structures, power plant structures, equipment support). No segment of the project shall have more than one responsible engineer. The transmission line may be the responsibility of a separate California registered electrical engineer. The civil, geotechnical or civil and design engineer assigned in conformance with Facility Design condition **GEN-5**, may be responsible for design and review of the TSE facilities.

The project owner shall submit to the CBO for review and approval, the names, qualifications and registration numbers of all engineers assigned to the project. If any one of the designated engineers is subsequently reassigned or replaced, the project owner shall submit the name, qualifications and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer. This engineer shall be authorized to halt earthwork and to require changes; if site conditions are unsafe or do not conform with predicted conditions used as a basis for design of earthwork or foundations.

The electrical engineer shall:

1. Be responsible for the electrical design of the power plant switchyard, outlet and termination facilities; and
2. Sign and stamp electrical design drawings, plans, specifications, and calculations.

<u>Verification:</u> At least 30 days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of rough grading, the project owner shall submit to the CBO for review and approval, the names, qualifications and registration numbers of all the responsible engineers assigned to the project. The project owner shall notify the CPM of the CBO's approvals of the engineers within five days of the approval.

If the designated responsible engineer is subsequently reassigned or replaced, the project owner has five days in which to submit the name, qualifications, and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer within five days of the approval. [3/12/03]

TSE-3 If any discrepancy in design and/or construction is discovered in any engineering work that has undergone CBO design review and approval, the project owner shall document the discrepancy and recommend corrective action. (1998 CBC, Chapter 1, Section 108.4, Approval Required; Chapter 17, Section 1701.3, Duties and Responsibilities of the Special Inspector; Appendix Chapter 33, Section 3317.7, Notification of Noncompliance]. The discrepancy documentation shall become a controlled document and shall be submitted to the CBO for review and approval and shall reference this condition of certification.

__Verification:__ The project owner shall submit a copy of the CBO's approval or disapproval of any corrective action taken to resolve a discrepancy to the CPM within 15 days of receipt. If disapproved, the project owner shall advise the CPM, within five days, the reason for disapproval, and the revised corrective action required obtaining the CBO's approval.

TSE-4 For the power plant switchyard, outlet line and termination, the project owner shall not begin any increment of construction until plans for that increment have been approved by the CBO. These plans, together with design changes and design change notices, shall remain on the site for one year after completion of construction. The project owner shall request that the CBO inspect the installation to ensure compliance with the requirements of applicable LORS. The following activities shall be reported in the MCR:

a) receipt or delay of major electrical equipment;

b) testing or energization of major electrical equipment; and

c) the number of electrical drawings approved, submitted for approval, and still to be submitted.

__Verification:__ At least 30 days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of each increment of construction, the project owner shall submit to the CBO for review and approval the final design plans, specifications and calculations for equipment and systems of the power plant switchyard, outlet line and termination, including a copy of the signed and stamped statement from the responsible electrical engineer attesting to compliance with the applicable LORS, and send the CPM a copy of the transmittal letter in the next Monthly Compliance Report.

TSE-5 The project owner shall ensure that the design, construction and operation of the proposed transmission facilities will conform to all applicable LORS, including the requirements listed below. The project owner shall submit the required number of copies of the design drawings and calculations as determined by the CBO.

a) HECA will be interconnected to PG&E grid via a 230 kV, 1272 kcmil ACSR per phase, approximately 2.8 miles long single circuit. The HECA project on site switching station consist of a breaker, a disconnect switch and PG&E revenue metering equipments. The proposed new PG&E switchyard will consist of 8 Circuit breakers, three-bay, six positions breaker and-a-half configuration.

b) The power plant outlet line shall meet or exceed the electrical, mechanical, civil and structural requirements of CPUC General Order 95 or National Electric Safety Code (NESC), Title 8 of the California Code and Regulations (Title 8), Articles 35, 36 and 37 of the "High Voltage Electric Safety Orders", Cal-ISO standards, National Electric Code (NEC) and related industry standards.

c) Breakers and busses in the power plant switchyard and other switchyards, where applicable, shall be sized to comply with a short-circuit analysis.

d) Outlet line crossings and line parallels with transmission and distribution facilities shall be coordinated with the transmission line owner and comply with the owner's standards.

e) The project conductors shall be sized to accommodate the full output from the project.

f) Termination facilities shall comply with applicable PG&E interconnection standards.

g) The project owner shall provide to the CPM:

   i) Executed project owner and California ISO Large Generator Interconnection Agreement

Verification: At least 60 days prior to the start of construction of transmission facilities (or a lessor number of days mutually agreed to by the project owner and CBO, the project owner shall submit to the CBO for approval:

a) Design drawings, specifications and calculations conforming with CPUC General Order 95 or NESC, Title 8, Articles 35, 36 and 37 of the "High Voltage Electric Safety Orders", NEC, applicable interconnection standards and related industry standards, for the poles/towers, foundations, anchor bolts, conductors, grounding systems and major switchyard equipment.

b) For each element of the transmission facilities identified above, the submittal package to the CBO shall contain the design criteria, a discussion of the calculation method(s), a sample calculation based on "worst case conditions"[1] and a statement signed and sealed by the registered engineer in responsible charge, or other acceptable alternative verification, that the transmission element(s) will conform with CPUC General Order 95 or NESC, Title 8, California Code of Regulations, Articles 35, 36 and 37 of the, "High Voltage Electric Safety Orders", NEC, applicable interconnection standards, and related industry standards.

c) Electrical one-line diagrams signed and sealed by the registered professional electrical engineer in responsible charge, a route map, and an engineering description of equipment and the configurations covered by requirements **TSE-5** a) through f) above.

d) The executed Large Generator Interconnection Agreement.

TSE-6 The project owner shall inform the CPM and CBO of any impending changes, which may not conform to the requirements **TSE-5** a) through f, and have not, received CPM and CBO approval, and request approval to implement such changes. A detailed description of the proposed change and complete engineering, environmental, and economic rationale for the change shall accompany the request. Construction involving changed equipment or substation

[1] Worst case conditions for the foundations would include for instance, a dead-end or angle pole.

configurations shall not begin without prior written approval of the changes by the CBO and the CPM.

Verification: At least 60 days prior to the construction of transmission facilities, the project owner shall inform the CBO and the CPM of any impending changes which may not conform to requirements of **TSE-5** and request approval to implement such changes.

TSE-7 The project owner shall provide the following Notice to the California Independent System Operator (California ISO) prior to synchronizing the facility with the California Transmission system:

1. At least one week prior to synchronizing the facility with the grid for testing, provide the California ISO a letter stating the proposed date of synchronization; and
2. At least one business day prior to synchronizing the facility with the grid for testing, provide telephone notification to the ISO Outage Coordination Department.

Verification: The project owner shall provide copies of the California ISO letter to the CPM when it is sent to the California ISO one week prior to initial synchronization with the grid. The project owner shall contact the California ISO Outage Coordination Department, Monday through Friday, between the hours of 0700 and 1530 at (916) 351-2300 at least one business day prior to synchronizing the facility with the grid for testing. A report of conversation with the California ISO shall be provided electronically to the CPM one day before synchronizing the facility with the California transmission system for the first time.

TSE-8 The project owner shall be responsible for the inspection of the transmission facilities during and after project construction, and any subsequent CPM and CBO approved changes thereto, to ensure conformance with CPUC GO-95 or NESC, Title 8, CCR, Articles 35, 36 and 37 of the, "High Voltage Electric Safety Orders", applicable interconnection standards, NEC and related industry standards. In case of non-conformance, the project owner shall inform the CPM and CBO in writing, within 10 days of discovering such non-conformance and describe the corrective actions to be taken.

Verification: Within 60 days after first synchronization of the project, the project owner shall transmit to the CPM and CBO:

a) "As built" engineering description(s) and one-line drawings of the electrical portion of the facilities signed and sealed by the registered electrical engineer in responsible charge. A statement attesting to conformance with CPUC GO-95 or NESC, Title 8, California Code of Regulations, Articles 35, 36 and 37 of the, "High Voltage Electric Safety Orders", and applicable interconnection standards, NEC, related industry standards, and these conditions shall be provided concurrently.

b) An "as built" engineering description of the mechanical, structural, and civil portion of the transmission facilities signed and sealed by the registered engineer in responsible charge or acceptable alternative verification. "As built" drawings of the electrical, mechanical, structural, and civil portion of the transmission facilities shall be maintained at the power plant and made available, if requested, for CPM audit as set forth in the “Compliance Monitoring Plan”.

c) A summary of inspections of the completed transmission facilities, and identification of any nonconforming work and corrective actions taken, signed and sealed by the registered engineer in charge.

REFERENCES

California ISO (California Independent System Operator). 1998a. Cal-ISO Tariff Scheduling Protocol posted April 1998, Amendments 1,4,5,6, and 7 incorporated.

California ISO (California Independent System Operator). 1998b. Cal-ISO Dispatch Protocol posted April 1998.

California ISO (California Independent System Operator). 2002a. Cal-ISO Grid Planning Standards, February 2002.

CP 2013a, Hydrogen Energy International LLC, Hydrogen Energy California Project (Transitional Cluster 5 Phase 1) submitted to the California Energy Commission.

CP 2013b, Hydrogen Energy International LLC, Hydrogen Energy California Project (Amended Application for Certification) Submitted to the California Energy Commission.

NERC/WECC (North American Reliability Council / Western Electricity Coordinating Council), 2002. NERC/WECC Planning Standards, August 2002.

DEFINITION OF TERMS

AAC All Aluminum conductor.

ACSR Aluminum Conductor Steel-Reinforced.

SSAC Steel-Supported Aluminum Conductor.

Ampacity Current-carrying capacity, expressed in amperes, of a conductor at specified ambient conditions, at which damage to the conductor is nonexistent or deemed acceptable based on economic, safety, and reliability considerations.

Ampere The unit of current flowing in a conductor.

Bundled Two wires, 18 inches apart.

Bus Conductors that serve as a common connection for two or more circuits.

Conductor The part of the transmission line (the wire) that carries the current.

Congestion Management

Congestion management is a scheduling protocol, which provides that dispatched generation and transmission loading (imports) will not violate criteria.

Emergency Overload
: See Single Contingency. This is also called an L-1.

Kcmil or KCM
: Thousand circular mil. A unit of the conductor's cross sectional area, when divided by 1,273, the area in square inches is obtained.

Kilovolt (kV)
: A unit of potential difference, or voltage, between two conductors of a circuit, or between a conductor and the ground.

Loop
: An electrical cul de sac. A transmission configuration that interrupts an existing circuit, diverts it to another connection and returns it back to the interrupted circuit, thus forming a loop or cul de sac.

Megavar
: One megavolt ampere reactive.

Megavars
: Mega-volt-Ampere-Reactive. One million Volt-Ampere-Reactive. Reactive power is generally associated with the reactive nature of motor loads that must be fed by generation units in the system.

Megavolt Ampere (MVA)
: A unit of apparent power, equals the product of the line voltage in kilovolts, current in amperes, the square root of 3, and divided by 1000.

Megawatt (MW)
: A unit of power equivalent to 1,341 horsepower.

Normal Operation/ Normal Overload
: When all customers receive the power they are entitled to without interruption and at steady voltage, and no element of the transmission system is loaded beyond its continuous rating.

N-1 Condition
: See Single Contingency.

Outlet
: Transmission facilities (circuit, transformer, circuit breaker, etc.) linking generation facilities to the main grid.

Power Flow Analysis
: A power flow analysis is a forward-looking computer simulation of essentially all generation and transmission system facilities that identifies overloaded circuits, transformers and other equipment and system voltage levels.

Reactive Power
: Reactive power is generally associated with the reactive nature of motor loads that must be fed by generation units in the system. An adequate supply of reactive power is required to maintain voltage levels in the system.

Remedial Action Scheme (RAS)
: A remedial action scheme is an automatic control provision, which, for instance, will trip a selected generating unit upon a circuit overload.

SF6
: Sulfur hexafluoride is an insulating medium.

Single Contingency
: Also known as emergency or N-1 condition, occurs when one major transmission element (circuit, transformer, circuit breaker, etc.) or one generator is out of service.

Solid Dielectric Cable
: Copper or aluminum conductors that are insulated by solid polyethylene type insulation and covered by a metallic shield and outer polyethylene jacket.

Switchyard
: A power plant switchyard (switchyard) is an integral part of a power plant and is used as an outlet for one or more electric generators.

Thermal Rating
: See Ampacity.

TSE
: Transmission System Engineering.

Tap
: A transmission configuration creating an interconnection through a sort single circuit to a small or medium sized load or a generator. The new single circuit line is inserted into an existing circuit by utilizing breakers at existing terminals of the circuit, rather than installing breakers at the interconnection in a new switchyard.

Undercrossing
: A transmission configuration where a transmission line crosses below the conductors of another transmission line, generally at 90 degrees.

Underbuild
: A transmission or distribution configuration where a transmission or distribution circuit is attached to a transmission tower or pole below (under) the principle transmission line conductors.

ALTERNATIVES

Negar Vahidi and Scott Debauche[1]

SUMMARY OF CONCLUSIONS

This analysis evaluates a reasonable range of potential alternatives to the proposed Hydrogen Energy California project (HECA or project). As California Environmental Quality Act (CEQA) lead agency for HECA, the California Energy Commission is required to identify and evaluate a range of reasonable alternatives to the project that would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project. As part of this analysis, staff evaluated HECA by comparing the applicant's stated project objectives to expected HECA attributes. The guiding principles for selection of alternatives analyzed are consistent with the CEQA Guidelines, Cal. Code Regs., tit. 14, §15000 et seq., as described below.

The U.S. Department of Energy (DOE) must decide whether to provide financial assistance for the construction of the project; it must comply with the National Environmental Policy Act (42 United States Code [U.S.C.] §§ 4321 et seq.) in making this decision. For DOE, the reasonable alternatives at this point in the NEPA analysis are: (1) to fund the construction and operation of the project as proposed by the applicant and subject to any conditions imposed by the Energy Commission or other regulatory agencies; or (2) to refrain from funding the construction and operation of the project.[2] DOE assumes for purposes of NEPA that a decision to refrain from funding the project would result in the applicant abandoning its project. This alternative is referred to as the "No Action Alternative" under NEPA. It is equivalent to the "No Project Alternative" under CEQA. The first NEPA alternative constitutes DOE's "Proposed Action" and is equivalent to the HECA project (for CEQA, the project is not considered an alternative). In considering the Proposed Action (HECA), DOE considers other "project-level" alternatives that Energy Commission staff analyzes below such as the alternatives involving no fertilizer manufacture, different modes of transporting materials to the site, and different routes for rail spurs, pipelines, and transmission lines. For purposes of DOE's NEPA review, these "project-level alternatives" constitute action alternatives to DOE's Proposed Action – funding the project as proposed by the applicant.

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[1] Preparation of this alternatives section includes technical analysis completed by staff issue area specialists. **Alternatives Appendix 1** of this staff assessment contains a list of staff contributors to the comparative and environmental analyses for alternatives evaluated in detail.

[2] DOE's NEPA procedures include specific requirements (10 CFR 1021.216) for analyzing alternatives in the context of competitive financial assistance. DOE reviews each responsive application and prepares an environmental critique for the official who will select the projects that will receive assistance. This brief comparative evaluation of environmental impacts allows the selecting official to make an informed decision when choosing projects for financial assistance. DOE then makes this information publicly available in an environmental synopsis that does not contain confidential and business sensitive information supplied by the applicants with their proposals. The environmental synopsis that discusses DOE's evaluation of the Proposed Action (HECA project) for financial assistance is included within the 2012 Amended AFC as Appendix B (HECA 2012e).

Based upon staff's analysis, the No Project Alternative would eliminate potentially significant environmental impacts associated with HECA, while the No Fertilizer Manufacturing Complex Alternative (Reduced Project Alternative) would lessen impacts in a number of environmental issue areas. **Alternatives Table 1** provides a brief comparison of the project environmental impacts and those of the alternatives evaluated in detail. The analysis of the DOE No Action Alternative is contained within each environmental issue area section of this Preliminary Staff Assessment and Draft Environmental Impact Statement (PSA/DEIS). A summary of NEPA requirements for alternatives analysis and the No Action Alternative is provided later in the subsection "NEPA Requirements." **Alternatives Table 1** provides summary details of alternatives analyzed within this PSA/DEIS.

Alternatives Table 3 provides a comparison of HECA to the applicant's stated project objectives. Energy Commission staff believes HECA is not likely to meet all of the applicant's stated objectives, as described further below. Thus, in the tables following **Alternatives Table 3,** staff evaluates HECA against those project objectives that it believes HECA could accomplish.

The identification of a CEQA environmentally superior alternative (Cal. Code Regs., tit. 14, §15126.6[e][2]) and NEPA environmentally preferred alternative (CEQ §1505.2[b]) will be identified in the Final Staff Assessment/Final Environmental Impact Statement (FSA/FEIS). At this time, Dry Cooling or Wet-Dry Hybrid Cooling Alternative, Natural Gas Combined Cycle with Carbon Capture and Storage Alternative, and Additional Alternative Sites remain under consideration. Staff will analyze these alternatives in the FSA/FEIS.

Five site alternatives (four presented by the applicant) were reviewed as potential alternative project sites and all were eliminated from detailed consideration.

Alternatives Table 1
Comparison of HECA and Alternatives

Alternatives Criteria	HECA Project[1] (CEQA)/ Proposed Action (NEPA)	No Project Alternative (CEQA)/ No Action Alternative (NEPA)[2]	No Fertilizer Manufacturing Complex (Reduced Project) Alternative (CEQA)[2] Action Alternative (NEPA)
Air Quality			
Construction related emissions	SM	Much less than HECA	Somewhat less than HECA
Project operations emissions	SM	Much less than HECA	Somewhat less than HECA
Biological Resources			
Loss of special-status species habitat	Indeterminate at this time	Much less than HECA	Similar to HECA
Impacts to wildlife regional movement	Indeterminate at this time	Much less than HECA	Similar to HECA
Habitat conversion	Indeterminate at this time	Much less than HECA	Similar to HECA
Impacts to San Joaquin kit fox Core Recovery Area	Indeterminate at this time	Much less than HECA	Similar to HECA
Potential take of state Fully Protected blunt-nosed leopard lizard	SU	Less than HECA	Similar to HECA
Increased risk of wildlife road mortality from increased traffic	Indeterminate at this time	Much less than HECA	Slightly less than HECA
Swainson's hawk foraging habitat loss	Indeterminate at this time	Much less than HECA	Similar to HECA
Potential loss of raptor nest trees and other migratory birds	Indeterminate at this time	Less than HECA	Similar to HECA
Potential impacts to wildlife exposed to contaminants from operation of evaporation ponds	SM	Less than HECA	Similar to HECA
Potential impacts to sensitive groundwater dependent vegetation	Indeterminate at this time	Less than HECA	Similar to HECA
Potential loss of jurisdictional state waters	Indeterminate at this time	Less than HECA	Similar to HECA
Potential loss of jurisdictional Waters of the U.S.	Indeterminate at this time	Less than HECA	Similar to HECA
Indirect effects to sensitive wildlife during construction and operation	SM	Less than HECA	Similar to HECA
Indirect effects to sensitive plant species during construction and operation	SM	Less than HECA	Similar to HECA
Potential direct impact to rare plant populations	Indeterminate at this time	Less than HECA	Similar to HECA

Alternatives Criteria	HECA Project[1] (CEQA)/ Proposed Action (NEPA)	No Project Alternative (CEQA)/ No Action Alternative (NEPA)[2]	No Fertilizer Manufacturing Complex (Reduced Project) Alternative (CEQA)[2] Action Alternative (NEPA)
Potential effects of nitrogen deposition to sensitive plants/wildlife	Indeterminate at this time	Less than HECA	Slightly less than HECA
Potential weed proliferation from increased GHG emissions during construction and operation	Indeterminate at this time	Less than HECA	Similar to HECA
Potential incremental contribution to cumulative effects to upland species of the southern San Joaquin Valley	Indeterminate at this time	Less than HECA	Similar to HECA
Impacts associated with CO_2-EOR project	Indeterminate at this time	Less than HECA	Similar to HECA
Carbon Sequestration and Greenhouse Gas Emissions			
Carbon sequestration	SM	Less than HECA	Same as HECA
Greenhouse gas emissions	SM	Less than HECA	Similar to HECA
Cultural Resources			
Potential Damage to Surface Archaeological Resources: HECA	PSU	Less than HECA	Similar to HECA
Potential Damage to Surface Archaeological Resources: EOR	Indeterminate at this time	Less than HECA	Same as HECA
Potential Damage to Buried Archaeological Resources: HECA/EOR	Indeterminate at this time	Less than HECA	Same as HECA
Potential Damage to Old Headquarters Weir	LS	Less than HECA	Same as HECA
Potential Damage to California Aqueduct	LS	Less than HECA	Same as HECA
Potential Impacts to Historic Built Environment Resources: EOR	Indeterminate at this time	Less than HECA	Same as HECA
Geology and Paleontology			
Potential impacts from strong seismic shaking	SM	Less than HECA	Similar to HECA
Potential impacts from soil failure caused by liquefaction, hydro-compaction, subsidence, expansive soils and/or dynamic compaction	SM	Less than HECA	Similar to HECA
Hazardous Materials	SM	Less than HECA	Slightly less than HECA
Land Use and Agriculture			
Conversion of prime farmland, unique farmland, or farmland of statewide importance.	PSM	Much less than HECA	Same as HECA

Alternatives Criteria	HECA Project[1] (CEQA)/ Proposed Action (NEPA)	No Project Alternative (CEQA)/ No Action Alternative (NEPA)[2]	No Fertilizer Manufacturing Complex (Reduced Project) Alternative (CEQA)[2] Action Alternative (NEPA)
Conflicts with existing agricultural zoning or Williamson Act contract.	PSM	Much less than HECA	Same as HECA
Conflict of zoning or cause rezoning of forestland.	—	Much less than HECA	Same as HECA
Result in loss of forest land.	—	Same as HECA	Same as HECA
Result in conversion of agricultural land to non-agricultural use.	PSM	Much less than HECA	Same as HECA
Physically divide or disrupt an established community.	PSM	Much less than HECA	Same as HECA
Conflict with any applicable land use plan, policy or regulation.	LS	Much less than HECA	Less than HECA
Conflict with applicable habitat conservation plan or natural community conservation plan.	—	Much less than HECA	Same as HECA
Noise and Vibration	SM	Less than HECA	Similar to HECA
Public Health and Safety	SM	Less than HECA	Slightly less than HECA
Socioeconomics			
Impacts to Socioeconomic Resources	LS	Less than HECA	Same as HECA
Soil and Surface Water			
Soil erosion by wind and water during project construction	PSM	Less than HECA	Less than HECA
Soil erosion by wind and water during project operations	PSM	Greater than HECA	Similar to HECA
Water quality impacts from contaminated storm water runoff	PSM	Somewhat greater than HECA	Somewhat less than HECA
Water quality impacts from increase of impervious areas	PSM	Less than HECA	Somewhat less than HECA
Water quality impacts from industrial operations	PSM	Less than HECA	Somewhat less than HECA
Water quality impacts from sanitary waste	PSM	Less than HECA	Similar to HECA
Potential impacts from on-site and off-site flooding	PSM	Somewhat greater than HECA	Similar to HECA
Potential to impede or redirect 100-year flood flows, as shown on Federal Emergency Management Agency maps	LS	Similar to HECA	Similar to HECA

Alternatives Criteria	HECA Project[1] (CEQA)/ Proposed Action (NEPA)	No Project Alternative (CEQA)/ No Action Alternative (NEPA)[2]	No Fertilizer Manufacturing Complex (Reduced Project) Alternative (CEQA)[2] Action Alternative (NEPA)
Impacts associated with CO_2-EOR project	PSM	Much less than HECA	Similar to HECA
Traffic & Transportation			
Potential impacts from increased traffic	SM	Much less than HECA	Less than HECA
Potential impacts from exhaust plumes	SM	Much less than HECA	Same as HECA
Transmission Line Safety and Nuisance			
Potential impacts from generated fields	LS	Less than HECA	Less than HECA
Fire, shock, and aviation impacts from physical presence	LS	Less than HECA	Less than HECA
Visual Resources			
Visual change/contrast of project facilities	SU	Much less than HECA	Same as HECA
Waste Management			
Potential for disposal or diversion of project materials to cause impacts on existing waste disposal or diversion facilities	PSU	Much less than HECA	Similar to HECA
Potential for impacts on human health and the environment related to past or present soil or water contamination	PSM	Less than HECA	Similar to HECA
Water Supply			
Water level lowering in local well owner wells	PSM	Much less than HECA	Indeterminate at this time
Increased Kern County sub-basin groundwater overdraft	PSM	Much less than HECA	Indeterminate at this time
Potential impacts to the California Aqueduct from subsidence	PSM	Less than HECA	Indeterminate at this time
Potential degradation of groundwater quality from project pumping	PSM	Much less than HECA	Indeterminate at this time
Potential non-compliance with State and Energy Commission water policies	PSM	Much less than HECA	Indeterminate at this time

Alternatives Criteria	HECA Project[1] (CEQA)/ Proposed Action (NEPA)	No Project Alternative (CEQA)/ No Action Alternative (NEPA)[2]	No Fertilizer Manufacturing Complex (Reduced Project) Alternative (CEQA)[2] Action Alternative (NEPA)
Worker Safety & Fire Protection	SM	Less than HECA	Slightly less than HECA

Notes: [1] The following correspond to impact determinations of HECA, as provided within each PSA/DEIS environmental analysis section:
— = no impact
LS = less than significant impact, no mitigation required
SM or PSM = significant or potentially significant impact that can be mitigated to less than significant
SU or PSU = significant and unavoidable or potentially significant and unavoidable impact that cannot be mitigated to less than significant

[2] This summary is comparative in nature, and corresponds to impact of the Alternative when compared to HECA as discussed within subsection "Alternatives Evaluated in Detail."

INTRODUCTION

DOE and Energy Commission staff reviewed the HECA alternatives analysis provided by the project applicant within the following documents:

- 2008 Application for Certification (AFC) (HEI 2008a);
- 2009 Revised AFC (HEI 2009c); and
- 2012 Amended AFC (HECA 2012e).

DOE and Energy Commission staff also analyzed alternatives recommended through agency and public comment, as well as those developed by staff (HECA 2012ll). Staff has evaluated the No Project Alternative and No Fertilizer Manufacturing Complex Alternative to meet the requirements of CEQA. The No Project Alternative has been evaluated to meet the requirements of NEPA for analyzing a No Action Alternative. While DOE will consider the No Fertilizer Manufacturing Complex Alternative, it doubts that this is a reasonable alternative under NEPA because the applicant would not proceed with its project if it does not include fertilizer manufacturing.

Dry Cooling or Wet-Dry Hybrid Cooling Alternative, Natural Gas Combined Cycle with Carbon Capture and Storage Alternative, and Additional Alternative Sites are alternatives still under consideration. Staff continues to evaluate these alternatives but cannot draw conclusions regarding their feasibility or ability to reduce significant environmental impacts, at this time. Final determinations and analysis of these alternatives (either eliminated from consideration or evaluated in detail) will be provided in the FSA/FEIS. Other alternatives eliminated from detailed analysis are also discussed in this section, as well as the reasons for eliminating them. The public is invited to comment on these alternatives and their feasibility.

On May 10, 2013, the applicant provided updated operating performance data developed in March 2013 for a hot day (97°F), a typical day (65°F) and a cold day (39°F). This updated data included an assumed 8,000 hours per year of operation, with the facility in a “maximum electricity production” mode for 16 hours per day and a “maximum fertilizer production” mode the remaining eight hours per day. On a typical day at 65°F, in the “electricity” mode, the facility would produce a net increase in electrical grid capacity of 52.5 megawatts (MW); and in the “fertilizer” mode on that same typical day the facility would consume a net 61.8 MW from the electrical grid. The grid-level change takes into account all electricity required to operate the facility as proposed by the applicant, including the air separation unit planned to be operated by a separate party and also including electricity consumed to recycle and re-inject the carbon dioxide produced with crude oil production. See the PSA/DEIS section on **Carbon Sequestration and Greenhouse Gas Emissions** for more details. The weighted average daily electricity production would be 14.4 MW. These new operating data were not available in time to inform the discussion below analyzing the No Fertilizer Manufacturing Complex (Reduced Project) Alternative (refer to subsection “Alternatives Evaluated in Detailed”), and evaluations and conclusions could be different when considering these new operating data in the FSA/FEIS.

NEPA REQUIREMENTS

DOE's Proposed Action is to provide financial assistance for the construction and operation of the HECA project, which would produce and sell electricity, carbon dioxide and fertilizer. DOE selected this project for an award of financial assistance through a competitive process under the Clean Coal Power Initiative (CCPI) program.

This PSA/DEIS will inform DOE's decision on whether to provide financial assistance for construction and operation of the project under its CCPI Program; DOE's financial assistance (or "cost share") would be limited to $408 million, about 10 percent of the project's total cost. DOE's financial assistance is also limited to certain aspects of the power and manufacturing plants, carbon capture, and sequestration. The PSA/DEIS evaluates the potential impacts of DOE's Proposed Action, the HECA project and its connected actions, and reasonable alternatives to DOE's Proposed Action.

PURPOSE AND NEED FOR DOE ACTION

Unlike the Energy Commission, DOE does not have regulatory jurisdiction over the HECA project. Its decisions are limited to whether and under what circumstances it would provide financial assistance to the project. The purpose and need for DOE action – providing limited financial assistance to the HECA project – is to advance DOE's CCPI program by funding projects that have the best chance of achieving the program's objective as established by Congress. The objective of the CCPI program is the commercialization of clean coal technologies that improve efficiency, environmental performance, and cost competitiveness well beyond those of technologies that are currently in commercial service.

NEPA ALTERNATIVES

NEPA requires that a federal agency evaluate the range of reasonable alternatives to the agency's proposed action. The range of reasonable alternatives encompasses those alternatives that would satisfy the underlying purpose and need for agency action. The purpose and need for DOE action – providing limited financial assistance to the HECA project – are to advance the CCPI program by selecting projects that have the best chance of achieving the program's objective as established by Congress. DOE's purpose and need is therefore different from the Energy Commission's, and DOE's alternatives differ somewhat from those of the Energy Commission, although many of them are the same.

DOE's NEPA regulations include a process for identifying and analyzing reasonable alternatives in the context of providing financial assistance through a competitive selection of projects proposed by entities outside the federal government. The range of reasonable alternatives in competitions for grants, loans and other financial support is defined in large part by the range of responsive proposals DOE receives. Unlike projects undertaken by DOE itself, the Department cannot mandate what outside entities propose, where they propose to do it, or how they propose to do it beyond establishing requirements in the funding opportunity announcement that further the program's objectives. DOE's decision is limited to selecting among the applications submitted by project sponsors that meet CCPI's goals.

Recognizing that the range of reasonable alternatives in the context of financial assistance and contracting is in large part determined by the number and nature of the proposals submitted, section 216 of DOE's NEPA regulations requires the Department to prepare an "environmental critique" that assesses the environmental impacts and issues relating to each of the proposals that the DOE selecting official considers for an award. *See* 10 C.F.R. § 1021.216. This official considers these impacts and issues, along with other aspects of the proposals (such as technical merit and financial ability) and the program's objectives, in making awards. DOE prepared a critique of the proposals that were deemed suitable for selection in this round of awards for the CCPI program.

DOE received 11 applications in response to the initial Funding Opportunity Announcement (FOA) issued August 11, 2008 for CCPI Round 3, all of which DOE determined met the mandatory eligibility requirements listed in the FOA (HECA 2012e, Appendix B). The applications covered a wide geographic range, including sites in 14 different states representing nearly every region of the country. In response to the reopened announcement (issued June 9, 2009), DOE received 38 applications, of which 25 were determined to have met the mandatory eligibility requirements listed in the announcement (HECA 2012e, Appendix B). The 25 applications offered projects involving sites in 19 different states representing nearly all geographic regions of the country (HECA 2012e, Appendix B).

The applications were evaluated against technical, financial, and environmental factors. By broadly soliciting proposals to meet the programmatic purpose and need for DOE action and by evaluating the potential environmental impacts associated with each proposal before selecting projects, DOE considered a reasonable range of alternatives for meeting the purpose and need of the CCPI solicitation (HECA 2012e, Appendix B). A detailed synopsis of the DOE CCPI Round 3 process and selection criteria is provided as Appendix B in the 2012 Amended AFC (HECA 2012e, Appendix B) and summarized in the subsection "DOE Alternatives Screening Process."

Once DOE selects a project for an award, the range of reasonable alternatives becomes the project as proposed by the applicant, any alternatives still under consideration by the applicant or agencies with regulatory jurisdiction over the project, and those that are reasonable within the confines of the project as proposed (e.g., the particular location of the generating plant on the site or the rights-of-way (ROWs) for linear facilities), and a No Action Alternative. Regarding the No Action Alternative, DOE assumes for purposes of the PSA/DEIS that, if it were to decide to withhold financial assistance from the project, the project would not proceed

As noted above under the subsection "Introduction," the "project-specific" alternatives that the applicant or the Energy Commission are still considering such as the coal delivery alternatives, dry cooling, wet-dry hybrid cooling, and other alternatives developed by the Energy Commission staff or suggested by the public are still under consideration. DOE would not make any decisions regarding these – the applicant or Energy Commission will make those decisions. Under the No Action Alternative, DOE would not provide funding to HECA. DOE assumes that the project applicant would not pursue its project, and there would be no impacts from the project. This alternative would not meet DOE's purpose and need for its CCPI program; however, DOE analyzes this option as its No Action Alternative in order to have a meaningful comparison between the impacts of DOE providing financial assistance and withholding that assistance.

CEQA REQUIREMENTS

As the CEQA lead agency for the HECA project, the California Energy Commission (Energy Commission) is required to consider and discuss alternatives to HECA. The guiding principles for the selection of alternatives for analysis are provided by the Energy Commission siting regulations and the CEQA Guidelines (Cal. Code Regs., tit. 14, § 15000 et seq.). Section 15126.6 of the CEQA Guidelines indicates that the alternatives analysis must:

- Describe a range of reasonable alternatives to the project, or to the location of the project, which would feasibly attain most of the basic objectives of the project;
- Consider alternatives that would avoid or substantially lessen any significant environmental impacts of the project, including alternatives that would be more costly or would otherwise impede the project's objectives; and
- Evaluate the comparative merits of the alternatives.

The lead agency is responsible for selecting a range of project alternatives for examination and must publicly disclose its reasoning for selecting those alternatives (Cal. Code Regs., tit. 14, §15126.6[a]). CEQA does not require an agency to "consider every conceivable alternative to a project." Rather, CEQA requires consideration of a "reasonable range of potentially feasible alternatives." The reasonable range of alternatives must be selected and discussed in a manner that fosters meaningful public participation and informed decision making (Cal. Code Regs., tit. 14, §15126.6[f]). That is, the range of alternatives presented in this analysis is limited to ones that will inform a reasoned choice by the Energy Commissioners. Under the "rule of reason," an agency need not consider an alternative whose effect cannot be reasonably ascertained and whose implementation is remote and speculative (Cal. Code Regs., tit. 14, §15126.6[f][3]).

The CEQA lead agency is also required to:

(1) Evaluate a no project alternative,

(2) Identify alternatives that were initially considered but then rejected from further evaluation, and

(3) Identify the environmentally superior alternative among the other alternatives (Cal. Code Regs., tit. 14, §15126.6)

Alternatives may be eliminated from detailed consideration by the lead agency if they fail to meet most of the basic project objectives, are infeasible, or could not avoid any significant environmental effects (Cal. Code Regs., tit. 14, §15126.6[c]).

PROJECT OBJECTIVES

The process for selecting alternatives to evaluate under CEQA begins with the establishment of project objectives. Section 15124 of the CEQA Guidelines defines the requirement for a statement of objectives (Cal. Code Regs., tit. 14, §15124[b]):

> "A clearly written statement of objectives will help the lead agency develop a reasonable range of alternatives to evaluate in the EIR and will aid the decision makers in preparing findings or a statement of overriding considerations, if necessary. The statement of objectives should include the underlying purpose of the project."

The objectives for HECA as claimed by the applicant are to (HECA 2012e):

- Provide dependable, low-carbon electricity to help meet future power needs, and to help back-up intermittent renewable power sources, to support a reliable power grid.
- Enhance the production and availability of in-state nitrogen-based products for use in agricultural, transportation, and industrial applications by producing approximately 1 million tons per year of low-carbon products, including urea, UAN (a solution of urea and ammonium nitrate in water used as a fertilizer), and anhydrous ammonia.
- Conserve domestic energy supplies and enhance energy security by using abundant solid feedstocks, coal and petroleum coke, to generate electricity and manufacture low-carbon nitrogen based products.
- Mitigate impacts related to climate change by dramatically reducing average annual greenhouse gas (GHG) emissions relative to those emitted from a conventional coal-fired power plant and/or nitrogen-based product manufacturing facility by capturing, at a rate of at least 90 percent, and sequestering carbon dioxide (CO_2).
- Use captured CO_2 for enhanced oil recovery (EOR) to produce additional oil reserves.
- Demonstrate advanced solid fuel based technologies that can generate clean, reliable, and affordable electricity in the United States and prove out carbon capture and sequestration as a viable method for reducing the carbon footprint of power generation and manufacturing.
- Facilitate and support the development of hydrogen infrastructure in California by supplementing the quantities of hydrogen available for future energy and transportation technologies.
- Minimize environmental impacts associated with the construction and operation of the project through technology selection, project design, and implementation of feasible mitigation measures, where necessary.
- Site the project at a location over which SCS Energy California LLC (SCS Energy or project applicant) will have control, and which offers reasonable access to necessary infrastructure, including natural gas, process water supply, transmission and rail interconnection, and geologic formations appropriate for CO_2 EOR and sequestration.
- Ensure the economic viability of the project by integrating electricity production with the manufacture of multiple products to meet market demand.
- Meet all requirements necessary to secure and retain DOE funding for the project.

ENERGY COMMISSION STAFF'S ALTERNATIVES SCREENING PROCESS

Pursuant to CEQA, the purpose of staff's alternatives analysis is to identify potential significant impacts of HECA and then focus on alternatives that are capable of avoiding or substantially reducing those impacts while still meeting most of the basic objectives of the project.

To prepare the analysis of alternatives, staff used the methodology summarized below:

- Describe the objectives of the project and compare those against possible alternatives to the project;
- Identify any potential significant environmental impacts of the project;
- Evaluate the project as proposed by the applicant against their stated project objectives and evaluate alternatives against project objectives that staff believes HECA could meet;
- Identify and evaluate feasible alternatives that meet most of the project objectives that HECA could meet, to determine whether such alternatives would avoid or substantially lessen project impacts identified as significantly adverse, and determine whether such alternatives would result in impacts that are the same, less than, or greater than those of the project; and
- Evaluate the comparative merits of the alternatives.

ALTERNATIVES CONSIDERED IN THE APPLICATION FOR CERTIFICATION

The following provides a summary description and overview of all alternatives presented within the 2008 Application for Certification (AFC) (HEI 2008a), the 2009 Revised AFC (HEI 2009c), and the 2012 Amended AFC (HECA 2012e). An analysis of the alternatives eliminated from further consideration is provided later in the subsection "Alternatives Eliminated From Detailed Consideration." Those alternatives requiring comparative analysis to HECA are discussed later in the subsection "Alternatives Evaluated In Detail."

OFF-SITE ALTERNATIVES

Multiple siting evaluations in various parts of the state have been conducted since the HECA project was initially conceived. Because the project's fundamental goals include CO_2 capture and sequestration, the siting process has focused on the distance to, and viability of, carbon sequestration at or near the site, as well as other essential criteria (discussed in 2012 Amended AFC, Section 6.3).

During the siting evaluations, various factors have contributed to the elimination of sites, including but not limited to the criteria outlined in Section 6.0 of the 2012 Amended AFC (HECA 2012e). For example, locations evaluated outside of Kern County included the following (HECA 2012ll, Data Response A200):

- <u>Los Angeles County</u>. The project applicant considered siting the project on the property of the British Petroleum (BP) Carson Refinery in Los Angeles County, where the refinery could provide HECA with petroleum coke (petcoke), and HECA could provide the refinery with steam. However, in 2007, the applicant was unable to reach consensus with the multiple owners and operator of a nearby oil field for a viable off-take agreement for CO_2 injection.

- Ventura County. Siting within Ventura County was considered. Work on this was discontinued due to the lack of viable site locations, proven sequestration targets, and the distance from existing transmission infrastructure.

The HECA project has been proposed in three main filings with the Energy Commission, as follows:

- July 2008. An AFC (HEI 2008a) was submitted to the Energy Commission, proposing that the HECA project be located on a different site, south of the California Aqueduct.
- May 2009. A Revised AFC (HEI 2009c) was submitted to the Energy Commission, relocating the project to essentially the current project site, but with certain design differences when compared to the July 2008 filing.
- May 2012. An Amended AFC (HECA 2012e) was submitted to the Energy Commission, evaluating HECA on the current site as evaluated within this PSA/DEIS.

An AFC was submitted to the Energy Commission in July 2008, proposing that HECA be located south of the California Aqueduct. This site was located within the Elk Hills Oil Field (EHOF). After evaluating sites within and near the EHOF, the project applicant initially selected a moderately sloped site south of the California Aqueduct. Subsequent to filing the 2008 AFC, the site was moved following discussions with regulatory agencies regarding the presence of sensitive biological resources, and discussion of the site for inclusion in habitat protection plans. As a result, the project applicant conducted another extensive siting analysis to identify an alternative site near the EHOF.

Section 6.0 (Alternatives) of both the 2009 Revised AFC and the 2012 Amended AFC evaluated four additional site alternatives to the currently proposed HECA site, all within Kern County (HEI 2009c and HECA 2012e). The locations of the following four site alternatives are included in Amended AFC Section 6.0 (Alternatives), Figure 6-1, and include (HECA 2012e):

- Alternative Site 1: located approximately 1.1 miles west-northwest of the HECA site between Bellevue Road and Tupman Road, this 774 acre site is 98 percent farmland and 2 percent residential use (HECA 2012ll, Data Response A200).
- Alternative Site 2: located approximately 0.4 mile east of the HECA site south of Bellevue Road, this 769 acre site is 99.9 percent farmland and 0.1 percent canal use (HECA 2012ll, Data Response A200).
- Alternative Site 3: located approximately 4.0 miles north-northwest of the HECA site between Interstate 5 and State Route 58, this 515 acre site is 97 percent farmland and 3 percent undeveloped (HECA 2012ll, Data Response A200).
- Alternative Site 4: located approximately 13.2 miles southeast of the HECA site between Hill Road and Old River Road, this 4,199 acre site is 96 percent farmland

and 4 percent undeveloped (HECA 2012ll, Data Response A200).

The project applicant did not carry forward any of the four off-site alternatives for further evaluation because the characteristics of the sites did not meet the applicant's screening criteria (HECA 2012e). An analysis of these site alternatives is provided in the subsection "Alternatives Eliminated From Detailed Consideration."

ALTERNATIVE LINEAR UTILITIES ROUTES

Because the 2008 AFC proposed the HECA project at a different site, alternative linear infrastructure routes evaluated within the 2008 AFC are inapplicable to the current project site and, therefore, excluded from this discussion (HEI 2008a, Section 6.0). Additionally, as described in Section 6 (Alternatives) of the 2009 Revised AFC and 2012 Amended AFC, both natural gas and potable water line routing options were only minimally considered due to siting limitations and land ownership restrictions. As such, no alternate natural gas or potable water line routes were evaluated (HEI 2009c and HECA 2012e).

Within the 2009 Revised AFC, four route alternatives were screened for the transmission line between the project site and substation connection (HEI 2009c, Section 6.0). Of these four transmission line route alternatives, two were fully evaluated as viable alternatives within 2009 Revised AFC, Section 4.0.

Section 6.0 of the 2012 Amended AFC considered alternative linear electrical infrastructure routes for the HECA project, including interconnections to both Pacific Gas and Electric's (PG&E) Midway Substation north of the HECA site, as well as to a future PG&E switching station east of the site (HECA 2012e). Numerous routing options were evaluated in detail to the Midway Substation, including routes presented in the 2009 Revised AFC (HEI 2009c, Section 6.0).

As discussed in Section 2.0 of the 2012 Amended AFC, the project includes two options for transferring coal to the HECA site:

- <u>Rail Transportation</u>. An approximately 5-mile new industrial railroad spur would connect the HECA site to the existing San Joaquin Valley Railroad (SJVRR) Buttonwillow railroad line, north of the HECA site. This railroad spur would also be used to transport some HECA fertilizer complex products to customers.
- <u>Truck Transportation</u>. Truck transport would be via existing roads from an existing coal transloading facility northeast of the HECA site. The truck route distance is approximately 27 miles.

Because the HECA project includes both of these options, the analysis of these coal-transferring options is provided in detail within each technical section presented in Section 4.0 of this PSA/DEIS. DOE considers these alternatives to be among the project-level action alternatives to its Proposed Action.

ACID GAS REMOVAL SYSTEM ALTERNATIVES

As described in Section 6.0 of the 2012 Amended AFC, several acid gas removal (AGR) system alternatives were considered by the project applicant (HECA 2012e). Because only a few AGR methods have found widespread acceptance for gasification projects at the HECA project scale, and alternative methods are unlikely to reduce any project-related impacts, staff has not evaluated them further in this PSA/DEIS. For a description and analysis of potential AGR alternatives considered by the project applicant, please refer to Section 6.0 of the Amended AFC (HECA 2012e).

MANUFACTURING COMPLEX ALTERNATIVE

The major difference between the Revised AFC (2009) project and the Amended AFC (2012) project is the addition of the fertilizer manufacturing complex (HECA 2012ll, Response A207). Without the manufacturing complex, HECA would use the hydrogen to produce electricity only (HECA 2012ll, Response A207). The manufacturing complex simply allows HECA to use its hydrogen to produce fertilizers during periods of low electrical demand (HECA 2012ll, Response A207).

WATER SUPPLY ALTERNATIVES

As described in the 2012 Amended AFC Section 6.0, several potential alternative water supplies were studied for HECA, as well as potential technologies for reducing water demand. HECA would utilize groundwater as supplied by the Buena Vista Water Storage District (BVWSD).

The following briefly identify water supply options considered within the Amended AFC (2012) include (HECA 2012e, Section 6.0) that are no longer under consideration by Water Supply staff, and are therefore not discussed within the **Water Supply** section of this PSA/DIES:

- Ocean Water. The project site is approximately 75 miles from the Pacific Ocean. Although this supply is limitless, and desalination technology for its successful use proven, the capital cost for transporting, treating, and disposing of this option is high (>$500 million).
- Ocean Discharge. The project site is located approximately 75 miles from a significant source of wastewater disposed into the ocean. Although this supply is large, and technology for its successful use proven, the capital cost for transporting and treating the wastewater from this option is high (>$500 million).
- Brackish Water. Several alternative brackish water sources were considered in comparison to the HECA groundwater supplier (BVWSD), including:
  - **Industrial Wastewater**. Industrial wastewater in the form of produced water is available from the oilfields within 10 miles of the HECA site. Produced water refers to water that is “co-produced” from the many oil wells in the Kern County region. Produced water is an industrial wastewater that is separated from crude oil in the oil production process. Kern County oil well output is often 8 parts water to 1 part oil, leading to a large excess of produced water that the local oil producers must dispose of. The produced water is currently disposed by re-injection and discharge to evaporation ponds. There are approximately 15 million gallons per day (mgd) of produced water available when drawn from multiple locations within

a radius of 10 miles of the HECA site.

— **Semitropic Water Storage District**. The Semitropic Water Storage District (Semitropic) is in northwest Kern County. Agriculture in a portion of Semitropic District is impacted by shallow, brackish groundwater conditions resulting from agricultural irrigation. It has a groundwater storage capacity of 1.65 million acre-feet, with 650,000 acre-feet of capacity remaining. This impacted area is approximately 10 miles to the west/northwest of Wasco and affects an area of roughly 10 square miles.

- Inland Wastewaters. Several wastewater effluent providers were evaluated in comparison to the HECA groundwater supplier (BVWSD), including:

  — **Municipal Effluent**. The HECA site is located approximately 17 miles northeast of the city of Bakersfield Wastewater Treatment Plant #3. This plant treats a large portion of the municipal effluent generated from the city of Bakersfield. The project applicant contacted the city regarding their interest and availability in supplying water to the project. Currently, the city is selling its treated effluent to local farmers for irrigation purposes.

  — **Agricultural Wastewater**. Agricultural wastewater (i.e., tile drainage) is excess water from irrigation practices. Differing from Semitropic District water (as discussed above under Brackish Water), this source would be site specific as irrigation water from directly adjacent agricultural lands.

- Other Inland Waters. Several inland water supply providers were evaluated in comparison to the HECA groundwater supplier (BVWSD), including:

  — **State Water Project**. The State Water Project’s California Aqueduct is approximately 1,900 feet south of the HECA site. The project applicant does not have an allocation for the use of freshwater from the State Water Project.

  — **Fresh Groundwater**. Fresh groundwater is found in the vicinity of the HECA site and is feasibly available to the project.

  — **Municipal Water Supply**. Municipal water is available to the HECA project.

WASTEWATER DISPOSAL ALTERNATIVES

Section 6.0 of the 2012 Amended AFC considered several potential alternative wastewater disposal options in comparison to the HECA Zero Liquid Discharge (ZLD) wastewater system (HECA 2012e). Because ZLD is the preferred approach by the Energy Commission for reducing environmental impacts, alternatives to ZLD wastewater disposal are not evaluated further within this PSA/DEIS.

PUBLIC AND AGENCY PARTICIPATION

Preparation of the HECA alternatives analysis included Energy Commission staff’s participation in the following:

- Energy Commission Informational Hearing held in Tupman, CA (July 12, 2012) – TNs 65764, 67137, and 68216.
- Three Energy Commission staff workshops held in Bakersfield (November 7, 2012)

and Sacramento (June 20, 2012 and September 27, 2012) – TNs 68216, 65656, and 67137, respectively.

- One Energy Commission Committee meeting and one Committee Status Conference held in Sacramento (January 10, 2012 and January 16, 2013) – TN 68976.
- Energy Commission Staff Workshop – Water Supply, held in Sacramento (February 20, 2012) – TN 69387.
- San Joaquin Valley Air Pollution Control District Hearing – held on April 2, 2013 – TN 70249.

Oral and written agency, general public, and intervener comments regarding HECA project alternatives received during these meetings have been considered by staff in determining the scope and content of this analysis.

DOE published an Amended Notice of Intent (ANOI) in the *Federal Register* on June 19, 2012 (77 FR 36519). A public scoping meeting was conducted on July 12, 2012, at the Elk Hills Elementary School, in Tupman, California, and comments were accepted through August 3, 2012 (one week after July 27, 2012, the date the comment period closed). DOE considered these comments in identifying its reasonable alternatives for purposes of NEPA.

The following are public and agency written comments received during these public meetings and the ANOI scoping comment period that pertain to the CEQA and NEPA alternatives analysis:

- United States Environmental Protection Agency, TN 66381 – July 26, 2012: Requests that the alternatives analysis discuss the following alternatives:
    - Reduced Project Size Alternative
    - Alternative Technologies (for component processes)
    - Dry Cooling or Wet-Dry Hybrid Cooling Alternative
    - Dry Scrubbing Alternative
- Sierra Club, TN 66370 – July 27, 2012: Requests that the alternatives analysis discuss the following alternatives:
    - Renewable Energy Project Alternatives
    - No Fertilizer Production Alternative
    - Higher Percentage of Petcoke and/or Biomass Gasifier Alternative
    - Air Cooling System Alternative
    - Enclosed Ground Flare and Flare Recovery System Alternative
    - No Project Alternative
    - Consider the Local Economic Impact of the Different Alternatives and the Increased Health Care Costs
- Daniel Bell, TN 66248 – July 16, 2012: Requests that the alternatives analysis discuss other gasification processes besides the GE and Mitsubishi alternatives contained within the Amended AFC (2012), questioning what other technologies may use less coal in the process.
- Chris Romanini, TN 66382 – July 26, 2012: Requests that the alternatives analysis

include a no coal gasification alternative, suggesting a change to natural gas.

- Debbie Shepherd, TN 66498 – August 2, 2012: Requests that the alternatives analysis discuss a natural gas power plant instead of a coal-processing unit.
- California Public Utilities Commission, TN 68923 – December 13, 2012: Discusses the HECA rail line alignment, which passes through a primarily agricultural area, resulting in a high amount of slow moving agricultural vehicles at the rail crossings. This concern relates to potential rail line and coal storage alternatives.
- General public comments made during oral comment period at Energy Commission staff workshops and public meetings (as discussed above):
  - Solar photovoltaic (PV) Alternative, ensuring a discussion of tax generation of Solar PV Alternative versus HECA be included;
  - Rooftop Solar PV Alternative;
  - Natural Gas Alternative (versus coal); and
  - Water Supply Alternative as the proposed “brackish” water source is suitable for pistachio farming within Kern County.

In addition to these comments that were received during the public meetings and the ANOI scoping comment period, the following comment letters have been received:

- Kern County Planning and Community Development Department, TN 69831 – March 6, 2013: Requests that the alternatives analysis discuss/include the following (Kern County 2013a):
  - Review alternative sites for the HECA that do not contain Prime Agricultural Land.
  - Eliminate consideration of applicant’s Alternative Site 1, which is owned by the Romanini Family Trust (an intervener to the HECA).
  - Identify if the property owner(s) of Alternative Site 4 have been contacted by the project applicant, and consider this information in staff’s analysis of this alternative site.

An analysis of these alternatives, as well as those identified by staff, is provided below in the subsections “Alternatives Eliminated From Detailed Consideration” and “Alternatives Evaluated In Detail.”

POTENTIALLY SIGNIFICANT AND UNMITIGABLE ENVIRONMENTAL IMPACTS

The following identifies potentially significant and unmitigable impacts associated with HECA, as well as providing a brief analysis as to the cause of impact. HECA project significant and unmitigable impacts are the first addressed by staff when seeking to lessen or avoid project impacts via alternatives. However, while significant and unmitigable impacts were staff’s first focus when developing alternatives and evaluating them, all impacts were considered and evaluated for each alternative’s ability to lessen or avoid any HECA project-related impacts. It should be noted a number of issue areas and impact determinations remain unknown at the time of PSA/DEIS publication, and current impact determinations may change at the time of FSA/FEIS publication. Therefore, the following outline project-related significant and unmitigable impacts as determined by staff and identified within this PSA/DEIS (refer to **Alternatives Table 1**):

- Biological Resources:
  - — Traffic volumes and travel routes from fertilizer distribution pass through San Joaquin kit fox Core Recovery Areas.
  - — Facilities located on lands occupied by blunt-nosed leopard lizard habitat.
  - — CO_2 pipeline conflicts with a number of listed plant and wildlife species located within Elk Hills Oilfield.
- Visual Resources:
  - — Significant impact at KOP 1 (HECA). As of this PSA/DEIS, the applicant has indicated that it has reached out to the resident at KOP 1 regarding an off-site mitigation alternative (HECA, 2012q) that could reduce this impact to a less-than-significant level. As discussed within the **Visual Resources** PSA/DEIS section, staff has requested that the applicant provide more information/documentation on the off-site mitigation plan.

HECA's ABILITY TO MEET APPLICANT'S STATED PROJECT OBJECTIVES

The applicant's stated project objectives were described under "Project Objectives." However, the applicant has not shown how their project would meet these objectives, and Energy Commission staff believes that not all of these objectives would be met. As such, staff believes it is appropriate to first document which objectives HECA could meet, and then to evaluate alternatives against the project objectives. **Alternatives Table 2** lists all project objectives and sub-objectives that the applicant claims HECA could meet and staff's evaluation of them.

Alternatives Table 2
Comparison of HECA to Applicant's stated Project Objectives

HECA PROJECT OBJECTIVE	Meets Objective?	Consistency Analysis
Provide dependable, low-carbon electricity to help meet future power needs ….	No	HECA does not provide low-carbon electricity using the project description and scope used by Energy Commission staff. See the PSA/DEIS section titled "Carbon Sequestration and Greenhouse Gas Emissions" for a comparison of the approach used by the applicant and that used by staff. As evaluated by staff, during early operations the carbon intensity is greater than efficient natural gas fired power plants. During mature operations the carbon intensity of the electricity that would be provided by HECA is similar to other base load power plants recently approved by the Energy Commission.
…. and to help back-up intermittent renewable power sources, to support a reliable power grid.	No	HECA has not shown that it could provide capacity to help back-up intermittent renewable sources of electricity. To do so, it would have to be able to reliably ramp electricity production up and down. The California Independent System Operator would need to be able to dispatch HECA at a changing power output of about 5 MW per minute. The

HECA PROJECT OBJECTIVE	Meets Objective?	Consistency Analysis
		applicant has not stated that it could operate in this manner nor has it described how such operation would affect facility reliability or availability.
Enhance the production and availability of in-state nitrogen-based products for use in agricultural, transportation, and industrial applications by producing approximately one million tons per year of low-carbon products, including urea, UAN, and anhydrous ammonia.	Yes	
Conserve domestic energy supplies and enhance energy security by using abundant solid feed stocks, coal, and petroleum coke to generate electricity and manufacture low-carbon nitrogen based products.	Yes	
Mitigate impacts related to climate change by dramatically reducing average annual GHG emissions relative to those emitted from a conventional coal-fired power plant and/or nitrogen-based product manufacturing facility by capturing, at a rate of at least 90 percent, and sequestering CO_2.	Yes	
Use captured CO_2 for EOR to produce additional oil reserves.	Yes	However, HECA has not shown whether or not other methods could be used to produce targeted oil reserves.
Demonstrate advanced solid fuel based technologies that can generate clean, reliable, and affordable electricity in the United States and prove out carbon capture and sequestration as a viable method for reducing the carbon footprint of power generation and manufacturing.	Yes	However, HECA has not shown that the electricity produced would be competitive enough in price to meet its stated annual hours of operation.
… and prove out carbon capture and sequestration as a viable method for reducing the carbon footprint of power generation and manufacturing	No	HECA has not shown that it would reduce the carbon footprint of power generation facilities likely to be located in California.
Facilitate and support the development of hydrogen infrastructure in California by supplementing the quantities of hydrogen available for future energy and transportation technologies.	No	HECA has not shown that it would facilitate development of hydrogen infrastructure in California any more than would a steam reformer making hydrogen at a California refinery.
Minimize environmental impacts associated with the construction and operation of the project through technology selection, project design, and implementation of feasible mitigation measures, where necessary.	Yes	
Site the project at a location over which HECA LLC will have control, and which offers reasonable access to necessary infrastructure,	Yes	

HECA PROJECT OBJECTIVE	Meets Objective?	Consistency Analysis
including natural gas, process water supply, transmission and rail interconnection, and geologic formations appropriate for CO_2 EOR and sequestration.		
Ensure the economic viability of the project by integrating electricity production with the manufacture of multiple products to meet market demand.	Possibly	HECA has not shown that it is economically viable, especially given its expected annual hours of operation in the California electricity market.
Meet all requirements necessary to secure and retain DOE funding for the project.	Yes	

Notes: Even though staff has found HECA not meeting a number of project objectives and has provided a comment in the Consistency Analysis column, staff has evaluated alternatives against these project objectives.

ALTERNATIVES ELIMINATED FROM DETAILED CONSIDERATION

Section 15126.6(c) of the CEQA Guidelines defines the requirement to identify any alternatives that were considered by the lead agency but were rejected as infeasible. CEQA requires that the reasons underlying the lead agency's determination not to analyze these alternatives in detail be explained. Similarly, NEPA requires DOE to briefly discuss alternatives that were eliminated from detailed study and to explain why they were eliminated.

Of those alternatives identified earlier in the subsections "Alternatives Considered Within The Application For Certification" and "Public And Agency Participation," the following 10 (ten) alternatives were considered but eliminated from detailed consideration because they would not fulfill staff's alternatives screening criteria (i.e., to avoid or substantially lessen project impacts identified as significantly adverse). The following provides staff's reasons for eliminating these alternatives from detailed analysis. DOE agrees with Energy Commission staff that these 10 alternatives should be eliminated from further consideration.

ALTERNATIVE SITES

Since alternatives must consider the underlying objectives of the HECA project, staff confined the geographic area for site alternatives to be an independent analysis of:

- Potential sites located within the EHOF;
- Alternative sites considered by the project applicant within the AFC (2008), Revised AFC (2009), and Amended AFC (2012); and
- Alternative sites evaluated within California as part of the project applicant's DOE CCPI Program selection process and evaluation.

These site alternatives were evaluated by staff for their ability to fulfill project objectives and siting criteria, including but not limited to:

- Proximity to an available oil field for sequestration;
- Proximity to an available substation and switchyard;

- Location in an area appropriate for industrial development and potentially compatible with Kern County General Plan and Zoning Ordinance designations; and
- Proximity to infrastructural right-of-way demands, including coal and petroleum coke delivery, transmission lines, natural gas lines, and water delivery pipelines.

As described in the subsection “Energy Commission Staff Alternatives Screening Process,” staff evaluated these site alternatives to determine whether they would avoid or lessen project impacts identified as significantly adverse (refer to **Alternatives Table 2**).

ALTERNATIVE SITES WITHIN THE ELK HILLS OIL FIELD (EHOF)

<u>Original HECA Site</u>

The 2008 AFC evaluated the HECA project at a different site than that presented in the 2009 Revised AFC and 2012 Amended AFC. The location of this site is shown in Amended AFC Section 6.0, Figure 6-1 (HECA 2012e, Section 6.0). This 315-acre site is located approximately 1.1 miles south of the HECA site. This site was not evaluated in the 2012 Amended AFC because of the presence of sensitive biological resources, and for that reason, was eliminated from further consideration. The original HECA site was eliminated because of the significant impacts to sensitive biological resources.

<u>Additional Sites Within The EHOF</u>

Staff coordinated with Occidental of Elk Hills, Inc. staff (owners and operators of the EHOF) and independently reviewed the EHOF for a feasible alternative location to site the project. While land parcels suitable for siting HECA exist within the EHOF, environmental permitting would be extremely challenging as a large amount of the EHOF contains existing biological resource mitigation land (OXY 2013f). During the siting of HECA at the original project site, biological data indicated that the EHOF high-quality habitat mitigation lands contain fully-protected species. During this initial HECA coordination, the California Department of Fish and Wildlife (CDFW) stated that any lands within a one-mile buffer zone of HECA would no longer qualify as suitable habitat compensation lands because of the noise, lighting, and continuous activity associated with future plant operations (OXY 2013f). During evaluation of the original HECA site, CDFW recommended that HECA pursue purchasing developed agriculture lands adjacent to the EHOF for construction of the HECA project (OXY 2013f). Therefore, the project applicant selected the current HECA site for the project.

Based upon independent staff review of available land within the EHOF boundaries:

- Other 515-acre parcels within the EHOF either contain production equipment and/or service roads; and
- Other 515-acre parcels within the EHOF would impact adjacent conservation lands because HECA facilities would be sited within one-mile of adjacent conservation land buffer zones.

As such, staff has determined that siting HECA within the EHOF is infeasible.

As discussed in subsection “Public And Agency Participation,” the Kern County Planning and Community Development Department requested the review of an alternative site that is not designated as “Prime Agricultural Land.” It should be noted that in reviewing Kern County Zoning Map designations, virtually all parcels west of Interstate 5 and within a five-mile plus eastern radius of the EHOF are zoned by Kern County as Exclusive Agriculture (A) or Limited Agriculture (A-1) (Kern County 2013b). Therefore, any alternative sites in this area would impact Kern County agriculturally-zoned land.

To address Kern County’s request to avoid Prime Farmland, staff reviewed the EHOF for suitable sites that would avoid lands designated as Prime. According to the California Division of Land Resources Protection Farmland Mapping and Monitoring Program (FMMP), the EHOF is not designated as Prime Farmland (California Division of Land Resources Protection 2013). Because of the reasons discussed above, locating the project within the EHOF would be infeasible.

Alternative Sites 1 Through 4

As described in the subsection “Alternatives Considered Within The AFC,” four alternative sites for the project were evaluated in the 2012 Amended AFC. To establish feasibility and determine if Alternative Sites 1 through 4 would avoid or substantially lessen HECA impacts identified as significant (**Alternatives Table 1**), staff conducted an independent review of information related to topography; distance from the CO_2 custody transfer point; linear facility lengths; sensitive environmental receptors; and land availability for Alternative Sites 1 through 4. This review consisted of comparing these factors to the HECA site. A summary of this information is provided in **Alternatives Table 3**.

- **Topography**. The topography of Alternative Sites 1 through 4 is generally flat and similar to the HECA site. As such, these sites remain feasible from a topographical standpoint and would not significantly alter the amount of earthmoving activities associated when compared to the proposed site. As such, staff’s analysis concludes that topography is not a key factor in eliminating Alternative Sites 1 through 4.
- **Distance from the CO_2 Injection Facility**. The distance to the CO_2 injection point ranges from 3.2 miles (Alternative Site 2) to 13.6 miles (Alternative Site 4).
- **Linear Facility Length**. Although linear routes were not developed for Alternative Sites 1 through 4, straight-line measurements from the alternative site to the requested location (i.e., electrical and gas interconnection points, potable and process water supplies) are provided within **Alternatives Table 3** for comparison purposes. Distances from the sites to electrical transmission interconnection ranged from 0.9 mile (Alternative Site 2) to 15.1 miles (Alternative Site 4). Distances from the sites to natural gas interconnection ranged from 4.2 miles (Alternative Site 3) to 22.9 miles (Alternative Site 4). Distances from the site to potable water connection ranged from 0.02 mile (Alternative Site 2) to 15.6 miles (Alternative Site 4). Distances from the sites to the process water connection ranged from 9.2 miles (Alternative Site 3) to 29.7 miles (Alternative Site 4).
- **Sensitive Environmental Receptors**. None of the alternative sites are located in urban settings, and none are in proximity to a substantial number of residences. The

HECA site and Alternative Site 4 have the fewest residences in proximity to the site. Based on the California Natural Diversity Database search results, the most records of sensitive species are found in the area south of the California Aqueduct, which includes Alternative Site 4.

- **Land Availability**. Alternative Sites 1 through 4 are all used for agricultural purposes, and contain 96 percent farmland or greater. All of these sites contain Williamson Act Contract lands. In response to staff's data requests on Alternative Site 4, the project applicant responded that the property owner(s) are willing to sell their land (refer to land owner information provided in **Alternatives Table 3**).

As discussed in subsection "Public And Agency Participation," the Kern County Planning and Community Development Department informed staff that Alternative Site 1 is located on property that is owned by the Romanini Family Trust, an intervener on HECA. Therefore, staff assumes this site is not available for the project. Alternative Site 2 has been sold and is no longer available. Based on the inability of the project applicant to acquire either of these sites, Alternative Sites 1 and 2 have been eliminated by staff from further consideration.

Refer to **Alternatives Table 3** for a listing of the comparative data for Alternative Sites 3 and 4. Staff's analysis shows that Alternative Sites 3 and 4 would not avoid or substantially lessen project-related significant impacts to biological resources or land use and agriculture. While Alternative Sites 3 and 4 would result in slightly different CO_2 pipeline route lengths, the CO_2 pipelines from either site would need to traverse sensitive biological resource areas within the EHOF to reach the CO_2 injection location. Alternative Sites 3 and 4 would result in the removal of agricultural land. As discussed in subsection "Public And Agency Participation," the Kern County Planning and Community Development Department requested the review of an alternative site that is not designated as "Prime Agricultural Land." Alternative Site 3 is designated as Prime Farmland (California Division of Land Resources Protection 2013). Alternative Site 4 is designated as both Unique Farmland and Farmland of Statewide Importance (California Division of Land Resources Protection 2013).

Alternatives Table 3
Comparison Data for the HECA Site and Alternative Sites 1 through 4

Alternatives Criteria	Alternative Site 1	Alternative Site 2	Alternative Site 3	Alternative Site 4	HECA Site
Site Acreage	774	769	515	4,199	453 (Plus 653 acres of Controlled Area)
1. Topography					
Slope, topography description, and elevation	Description: The site is generally flat. The topography varies 10 feet throughout the site. Elevations: Minimum: 273 feet Maximum: 283 feet Average Slope: Less than 0.5 percent	Description: The site is generally flat. The topography varies 8 feet throughout the site. Elevations: Minimum: 288 feet Maximum: 296 feet Average Slope: Less than 0.5 percent	Description: The site is generally flat. The topography varies 12 feet throughout the site. Elevations: Minimum: 291 feet Maximum: 303 feet Average Slope: Less than 0.5 percent	Description: The site is generally flat. The topography varies 42 feet throughout the site Elevations: Minimum: 296 feet Maximum: 338 feet Average Slope: Less than 0.5 percent	Description: Generally flat. The topography varies 4 feet throughout the site. Elevations: Minimum: 284 feet Maximum: 288 feet Average Slope: Less than 0.5 percent
Potential Available Acreage	100 percent	100 percent	100 percent	100 percent	100 percent
2. Distance from CO_2 Custody Transfer Point					
Distance from CO_2 Injection Facility	3.6 miles	3.2 miles	8.0 miles	13.6 miles	4.0 miles
3. Lengths of Linear Facilities					
Electrical Transmission (Future PG&E Switching Station)	3.9 miles	0.9 mile	5.8 miles	15.1 miles	2.1 miles
Natural Gas	7.6 miles	7.2 miles	4.2 miles	22.9 miles	13.0 miles
Potable Water	3.0 miles	0.02 mile	5.2 miles	15.6 miles	1.0 mile
Process Water	11.0 miles	13.5 miles	9.2 miles	29.7 miles	15.0 miles
4.0 Sensitive Environmental Receptors					
Sensitive Environmental Receptors (including: residential, schools, hospitals, recreational areas, sensitive species habitat)	• Four residences within 1,000 feet • Elk Hills Elementary School – 4 miles • First Southern Baptist Church –3.75 miles • Buttonwillow Park – 3.5 miles away	• Seven residences within 1,000 feet • Elk Hills Elementary School – 2.5 miles • First Southern Baptist Church – 5.8 miles • Buttonwillow Park – 5.6 miles	• One residence within 1,500 feet, and three other residences within 5,500 feet • Buttonwillow Elementary School - 2.5 miles • Community Baptist Church – 2.1 miles • Buttonwillow Park – 1.6 miles	• Three residences within 3,500 feet • Lakeside Elementary School - 5 miles • First Southern Baptist Church –22.5 miles • Buttonwillow Park – 22.3 miles	• One residence within 1,400 feet, and one residence within 3,300 feet • Elk Hills Elementary • School – 1.3 miles • Tule Elk State Natural Reserve – 1,700 feet
5.0 Land Availability					
Land Ownership and	Private. Owner not	Private. Owner sold to	Private. Owner possibly	Private. Owner possibly	Private. Owner sold to

Alternatives Criteria	Alternative Site 1	Alternative Site 2	Alternative Site 3	Alternative Site 4	HECA Site
Acquisition	willing to sell.	another buyer.	willing to sell.	willing to sell.	HEI, LLC. HECA LLC has an option to purchase from HEI LLC.
Description of existing land uses.	98 percent Farmland • 752 acres of Prime Farmland • 20 acres of other farmland • 225 acres of alfalfa, 351 acres of cotton, 201 acres of pistachio 2 percent Residential	99.9 percent Farmland • 664 acres of Prime Farmland • 66 acres of other farmland • 34 acres of natural vegetation • 186 acres of alfalfa • 46 acres of cotton • 31 acres of wheat 0.1 percent Canals	97 percent Farmland • 297 acres of Prime Farmland • 218 acres of other farmland • 329 acres of almond • 67 acres of carrot • 75 acres of pistachio 3 percent Undeveloped	96 percent Farmland No Prime Farmland • 4,159 acres of other farmland (including 2,310 acres of uncultivated agricultural land) • 10 acres of natural vegetation • 8 acres of rural residential • 8 acre of alfalfa • 3 acres of cotton • 1,771 acres of wheat 4 percent Undeveloped	99.8 percent Farmland • 453 acres Prime Farmland 0.2 percent Industrial
Surrounding Land Uses	Land uses to the north, east, and west are mostly farmland, with a small amount of residential land use. Land use to the south is undeveloped and public or public/quasi-public. Farmland surrounding this alternative site is composed of Williamson Act Contracted Land, prime farmland, farmland on statewide importance, and semi-agriculture and rural commercial land.	The site is surrounded by farmland. There is a small amount of residential land use to the north and southwest. Land immediately south of the project is public/quasi-public. Farmland surrounding this alternative site is composed of Williamson Act Contracted Land, prime farmland, farmland of statewide importance, and semi-agriculture and rural commercial land.	Site located adjacent to Interstate 5. Land to the north of the site is farmland. Land to the west and south of the site is farmland, residential, and undeveloped. Land east of the site is undeveloped and commercial. Farmland surrounding this alternative site is composed of Williamson Act Contracted Land, prime farmland, farmland of statewide importance, and semi-agriculture	The site is surrounded by farmland. There are small areas of undeveloped land to the west of the site. There is some residential land southwest of the site. Land southeast of the site is mostly undeveloped with small residential and commercial areas. Farmland surrounding this alternative site is composed of Williamson Act Contracted Land, prime farmland, farmland of	Land use in the vicinity of the project site is primarily agricultural. Adjacent land uses include Adohr Road and agricultural uses to the north; Tupman Road and agricultural uses to the east; agricultural uses and an irrigation canal to the south; and Dairy Road right of way and agricultural uses to the west. The West Side Canal (Outlet Canal, KRFCC, and the California Aqueduct) are approximately 500,

Alternatives Criteria	Alternative Site 1	Alternative Site 2	Alternative Site 3	Alternative Site 4	HECA Site
	The surrounding farmland contains the following crop coverage: bok choy, cotton, alfalfa, wheat, onions, almonds, and persimmon.	The surrounding farmland contains the following crop coverage: bok choy, almonds, alfalfa, grape, tomato process, persimmon, cotton, and onion.	and rural commercial land. The surrounding farmland contains the following crop coverage: bok choy, almond, alfalfa, onion, carrot, wine grapes, sudan grass, and tomato process.	statewide importance, and semi-agriculture and rural commercial land. The surrounding farmland contains the following crop coverage: tomato process, wheat, alfalfa, onion, safflower, prune, pomegranate, wine grape, oats for food, corn for food, rapeseed, Napa cabbage, potato, and mustard.	700, and 1,900 feet south of the project site, respectively. Most of the land in the vicinity of the project site and linear routes is included in the Exclusive Agriculture (A) zone or the Limited Agriculture (A-1) zone. Farmland surrounding the project site is composed of Williamson Act Contracted Land, prime farmland, farmland of statewide importance, and semi-agriculture and rural commercial land. Land within 1 mile of the project site is primarily used for farming purposes (particularly the cultivation of cotton, alfalfa, and onions), undeveloped areas, and orchards for the cultivation of pistachios. The 453-acre project site and controlled area is currently used for farming purposes, including the cultivation of cotton, alfalfa, and onions.
Source: HECA 2012ll, Response A200					

Staff concludes that the increase in linear infrastructure associated with Alternative Sites 3 and 4 has the potential to result in an increase to significant biological resources and cultural impacts due to additional lengths traversing sensitive areas. Furthermore, while the linear routes serving Sites 3 and 4 can be partially assumed at this time, it is possible that these rights-of-way could create new and unknown land use incompatibility impacts. As such, the similar existing land uses of both sites (refer to **Alternatives Table 3)** and the required linear infrastructure right-of-way creates similar or worse significant impacts as those associated with HECA. Therefore, staff has eliminated Alternative Sites 3 and 4 from further consideration.

ALTERNATIVE LINEAR UTILITIES ROUTES

Linear Utility Infrastructure Routes

Section 6.0 of the 2008 AFC, 2009 Revised AFC, and 2012 Amended AFC evaluated electrical transmission interconnections to both Pacific Gas and Electric's (PG&E) Midway Substation north of the proposed HECA site, as well as to a future PG&E switching station east of the site (HEI 2008a, HEI 2009c, HECA 2012e).

PG&E Midway Substation Alternative. Numerous routing options were evaluated in Section 6.0 of the 2009 Revised AFC for interconnection to the PG&E Midway Substation (HEI 2009c). However, transmission interconnection to the PG&E Midway Substation has been eliminated from further consideration based on the following:

- PG&E has identified transmission interconnection congestion in and around the Midway Substation (HECA 2012e, Section 6.0); and
- PG&E's switching station represents the shortest and most direct interconnection point available to the site, with interconnection to the PG&E Midway Substation requiring a substantially longer transmission line length (i.e., more than five miles).

Due to the increased length, transmission interconnection into the PG&E Midway Substation would not avoid or lessen significant biological resources or land use and agriculture project impacts, as identified within **Alternatives Table 2**. Given congestion and increased impacts, an interconnection to the PG&E Midway Substation has been eliminated from further consideration.

PG&E Switching Station Route Alternatives. In selecting the HECA project interconnection route to the PG&E switching station, the following factors were provided to staff by the applicant and considered by staff within this analysis (**Alternatives Table 2)**:

- Feasibility of Land Acquisition. The proposed route involves a minimum number of landowners, with required right-of-way widths available for acquisition.
- Safety and Proximity to Potential Sensitive Receptors. There are no residences or other occupied buildings (i.e., residences, schools, day-care centers, etc.) along the entire HECA transmission interconnection route.

Because the HECA site is surrounded by agricultural uses, altering the transmission line interconnection route (lengthening) would increase temporary disturbance to agricultural uses. As such, staff's analysis shows that altering the proposed transmission line interconnection routes into the PG&E switching station would not avoid or substantially lessen significant biological resources or land use and agriculture project impacts, identified in **Alternatives Table 1**. Therefore, alternative interconnection routes to the PG&E switching station have been eliminated from further consideration.

Natural Gas Route Alternatives. The proposed PG&E natural gas pipeline would be co-located with the HECA railroad spur that would be utilized for coal and petroleum coke delivery. The natural gas supply pipeline would tap into PG&E's main supply pipeline. Based on review of alternative natural gas pipeline routes presented within Section 6.0 (Alternatives) of the AFC (2008), Revised AFC (2009), and Amended AFC (2012), the HECA pipeline route is intended to ensure:

- Collocation of two project linear facilities in the same right-of-way (i.e., the majority of the natural gas pipeline route with the railroad spur) to avoid siting of two separate routes; and
- Minimization of the length of the natural gas pipeline right-of-way interconnection to the PG&E main supply pipeline (i.e., for the remaining portion of the natural gas pipeline not collocated with the railroad spur).

The natural gas line would minimize total linear length and temporary land disturbance during installation. Because the site is surrounded by agricultural uses, altering the natural gas route would increase temporary disturbance to agricultural uses. As such, Energy Commission staff's analysis shows that altering the proposed underground natural gas pipeline route would not avoid or substantially lessen significant biological resources or land use and agriculture project impacts, identified in **Alternatives Table 1**. Furthermore, it should be noted that an alternative route could place this linear infrastructure closer to residents. Therefore, alternative natural gas pipeline routes are eliminated from further consideration.

CO_2 Pipeline Route Alternatives. As part of the project, an approximately three-mile CO_2 pipeline would transfer the CO_2 captured during gasification south to the Occidental of Elk Hills (OEHI) injection facility. The proposed CO_2 pipeline alignment has been sited to minimize impacts to resource areas, as discussed in the 2012 Amended AFC (HECA 2012e, Appendix A). Based on information provided in **Alternatives Table 2**, linear length distances to the OEHI CO_2 injection facility, alternative CO_2 pipeline routes would not avoid or lessen project-related significant biological resources or land use and agriculture impacts identified in **Alternatives Table 1**. The HECA CO_2 pipeline route minimizes length and occurs within lands controlled by the project applicant. Furthermore, it should be noted that an alternative route could place this linear infrastructure closer to residents. Therefore, staff has eliminated alternative CO_2 pipeline routes from further consideration.

WATER SUPPLY ALTERNATIVES

Please refer to the **Water Supply** section of this PSA/DEIS (Section 4.15), for a discussion of water supply alternatives identified earlier within the AFC. Also refer to the subsection "Alternatives Considered In The Application For Certification," for water supply alternatives still under consideration by staff.

REDUCED PROJECT ALTERNATIVES

As described in the subsection “Public And Agency Participation,” the US EPA and intervener comments requested the scope and content of this analysis include a Reduced Project Alternative. The HECA project would generate electricity and fertilizer (sequestering CO_2 in the gasification process). Reduced Project Alternatives could include reducing production of electricity or fertilizer and/or a reduced project footprint.

- Reduced Production of Electricity or Fertilizer and other Nitrogen-Based Products. To evaluate this alternative, staff requested data from the project applicant that would reduce the overall project by 25 percent (HECA 2012ll, Response A202). HECA has been configured around Mitsubishi Heavy Industries (MHI) gasification and combustion turbine technology. The project applicant has stated these two key equipment systems are only offered in the sizes used for HECA, and are not scalable by 25 percent or any other value. The selection of these key technologies also determines the amount of hydrogen that can be produced for combustion turbine fuel and fertilizer production, as well as the CO_2 available for Enhanced Oil Recovery (EOR) and permanent sequestration. The applicant has not provided any data showing that the gasifier could operate at a feedstock charge rate of less than that associated with full gasifier capacity. Issues that might arise when operating off-design point can include performance degradation, deviations in syngas quality and slag characteristics, maintenance issues, etc.

  Because electricity and fertilizer production technologies are not individually able to reduce output by 25 percent, a Reduced Project Alternative is best evaluated through the No Fertilizer Manufacturing Alternative. Without the fertilizer manufacturing complex, HECA could use hydrogen to produce electricity only. The fertilizer manufacturing complex simply allows HECA to use hydrogen to produce fertilizers during periods of low electrical demand (HECA 2012ll, Response A207). Reducing the manufacture of fertilizer has the potential to avoid or lessen a number of the significant project-related impacts identified in **Alternatives Table 1.** The No Fertilizer Manufacturing Complex (Reduced Project) Alternative is further evaluated below in the subsection “Alternatives Evaluated In Detail.”

- Reduced Project Footprint. According to the project applicant, the HECA engineering design work process includes optimizing the plot plan by minimizing the site footprint to the extent feasible, and accounting for space required for plant facilities and maintenance (HECA 2012ll, Response A202). Additionally, the HECA site boundary was selected to consider safety, constructability, and to lessen environmental impacts. A 25 percent reduction in the 453-acre footprint would only slightly decrease impacts to existing agricultural uses, as 99.8 percent of the site is used for agricultural production (refer to **Alternatives Table 3**). Therefore, reducing the project footprint would only slightly decrease the amount of agricultural land loss associated with the project. The remaining project site would continue to be impacted by the development of an industrial use sited within a Kern County agricultural zone. Impacts related to removal of agricultural land would be nominally lessened but not avoided. Furthermore, while this alternative would decrease the overall site boundary, it would not reduce ground disturbing activities as identical project features would still be built. As such, the Reduced Project Site Alternative is eliminated from further consideration because it would only nominally lessen project-related impacts to removal of agricultural land, which have been mitigated to a less than significant level (refer to **Land Use and Agriculture** section).

DRY SCRUBBING ALTERNATIVE

During the ANOI scoping comment period the US EPA recommended the evaluation of a dry scrubbing alternative to reduce the HECA water use. However, dry scrubbing is not applicable to an Integrated Gasification Combined Cycle (IGCC) plant such as HECA (HECA 2012ll, Response A204). Dry scrubbing is a post-combustion, low-pressure (near atmospheric) technology for removal of sulfur dioxide from a fired boiler flue gas stream. Air quality staff reviewed the information provided by the applicant regarding dry scrubbing and concur that this technology is not applicable to HECA. This alternative is not applicable, as the HECA project would not use a fire boiled flue gas stream. Therefore, a Dry Scrubbing Alternative to reduce water consumption would not be applicable to HECA and has been eliminated from further consideration.

RENEWABLE ENERGY PROJECT ALTERNATIVES

Public and intervener comments requested the scope and content of this analysis include a Renewable Energy Project Alternative. These comments did not identify any specific environmental impacts this alternative seeks to potentially lessen or avoid, but merely requested staff to compare this alternative against the HECA project. **Alternatives Table 4** provides an analysis of a renewable project alternative in comparison to the HECA objectives (as identified in the subsection "Project Objectives").

Alternatives Table 4
Comparison of Renewable Energy Project Alternative to HECA Project Objectives

HECA PROJECT OBJECTIVE	Meets Objective?	Consistency Analysis
Provide dependable, low-carbon electricity to help meet future power needs …. (Note: HECA may not meet this project objective.)	Potentially (biomass boiler)	Some renewable facilities, such as biomass fired boilers or geothermal resources, can provide dependable renewable power to the grid. Other renewable energy resources such as wind and solar facilities are intermittent and cannot provide dependable power by themselves. While geothermal facilities do not seem to be an alternative given the site location, biomass fueled facilities exist in Kern County and could be deployed at a sufficient scale to meet the new capacity that HECA would add to the electricity grid. However, the availability of sufficient nearby biomass is currently unknown.
… and to help back-up intermittent renewable power sources, to support a reliable power grid. (Note: HECA would not meet this project objective.)	Yes	Back-up supplies of electricity are not needed if the renewable energy project is base load, such as a biomass boiler.
Enhance the production and availability of in-state nitrogen-based products for use in agricultural, transportation, and industrial applications by producing approximately one million tons per year of low-carbon products, including urea, UAN, and	No	A Renewable Energy Project Alternative would not produce hydrogen that could be utilized in the production of nitrogen-based products. Therefore, a Renewable Energy Project Alternative would not attain this project objective.

HECA PROJECT OBJECTIVE	Meets Objective?	Consistency Analysis
anhydrous ammonia.		
Conserve domestic energy supplies and enhance energy security by using abundant solid feedstocks, coal, and petroleum coke to generate electricity and manufacture low-carbon nitrogen based products.	Potentially	A Renewable Energy Project Alternative would conserve domestic energy supplies. However, some Renewable Energy Project Alternatives would not utilize domestic solid feedstocks, coal, or petroleum coke to generate electricity and would not generate hydrogen that could be utilized in the production of nitrogen-based products. Therefore, a Renewable Energy Project Alternative may or may not attain this project objective.
Mitigate impacts related to climate change by dramatically reducing average annual GHG emissions relative to those emitted from a conventional power plant and/or nitrogen-based product manufacturing facility by capturing, at a rate of at least 90 percent, and sequestering CO_2.	No	A Renewable Energy Project Alternative would reduce GHG emissions toward mitigating impacts related to climate change relative to those emitted from a conventional power plant. However, while wind and solar Renewable Energy Project Alternative would not generate any GHG emissions (except solar thermal generators that utilize natural gas boilers), this type of project would not capture CO_2 for sequestration purposes nor generate hydrogen that could be utilized in the production of nitrogen-based products. Therefore, a Renewable Energy Project Alternative would not attain this project objective.
Use captured CO_2 for EOR to produce additional oil reserves.	No	A Renewable Energy Project Alternative would not capture CO_2 for enhanced oil recovery purposes. Therefore, a Renewable Energy Project Alternative would not attain his project objective.
Demonstrate advanced solid fuel based technologies that can generate clean, reliable, and affordable electricity in the United States … (Note: HECA may not meet this project objective.)	Potentially	A biomass fired boiler would utilize solid fuel based technologies to generate clean, reliable and affordable electricity.
… and prove out carbon capture and sequestration as a viable method for reducing the carbon footprint of power generation and manufacturing. (Note: HECA would not meet this project objective.)	No	Renewable Energy Project Alternatives would not capture CO_2 for sequestration purposes. Therefore, most Renewable Energy Project Alternatives would not attain this project objective.
Facilitate and support the development of hydrogen infrastructure in California by supplementing the quantities of hydrogen available for future energy and transportation technologies. (Note: HECA would not meet this project objective.)	No	A Renewable Energy Project Alternative would not produce hydrogen that could be utilized for energy generation purposes. Therefore, a Renewable Energy Project Alternative would not attain this project objective.
Minimize environmental impacts associated with the construction and operation of the project through technology selection, project design, and implementation of feasible mitigation measures, where necessary.	Yes	Absent knowing the specific type of renewable energy technology used, location of such a renewable energy site, or conducting a cursory environmental analysis, staff assumes a renewable energy facility of comparable net MW output to HECA can be completed in an environmentally responsible manner. Therefore, it is assumed most renewable energy projects of equal net MW output could attain this project objective.
Site the project at a location over which HECA LLC will have control, and which offers reasonable access to necessary infrastructure, including natural gas, process	No	While the HECA site does offer reasonable access to necessary infrastructure, a Renewable Energy Project Alternative would not capture CO_2 for sequestration purposes. Therefore, a Renewable Energy Project Alternative would not attain this project objective.

HECA PROJECT OBJECTIVE	Meets Objective?	Consistency Analysis
water supply, transmission and rail interconnection, and geologic formations appropriate for CO_2 EOR and sequestration.		
Ensure the economic viability of the project by integrating electricity production with the manufacture of multiple products to meet market demand. (Note: HECA may not meet this project objective.)	No	A Renewable Energy Project Alternative would not produce hydrogen that could be utilized for electricity generation and the production of fertilizer or other hydrogen based products. Therefore, a Renewable Energy Project Alternative would not attain this HECA project objective. However, a Renewable Energy Project Alternative might not need the revenue stream from by-product sales to be financially viable.
Meet all requirements necessary to secure and retain DOE funding for the project.	No	Because there would be no coal involved in biomass, solar or wind power generation, a Renewable Energy Project Alternative would not meet DOE CCPI Program funding requirements or the DOE purpose and need for HECA. Therefore, a Renewable Energy Project Alternative would not attain this project objective. However, a Renewable Energy Project Alternative might not need the DOE funding to be financially viable.

Based on the analysis in **Alternatives Table 3**, other than a biomass fired boiler, Renewable Energy Project Alternatives are inconsistent with most of the HECA project objectives (inconsistent with more than HECA). As such, except for biomass fired boilers, Renewable Energy Project Alternatives have been eliminated from further consideration (consistent with CEQA §15126.6[a]). A Biomass Boiler Alternative is discussed further under the subsection “Alternatives Still Under Consideration.”

NATURAL GAS PROJECT ALTERNATIVE

Public comments requested that the scope and content of this analysis include a Natural Gas Project Alternative. These comments did not identify any specific environmental impacts this alternative would potentially lessen or avoid, but merely requested staff to compare this alternative against the HECA project. Staff has conducted an analysis of a Natural Gas Project Alternative in the form of a conventional natural gas-fired electric generation facility at the HECA site that would generate electricity only. Staff’s analysis of this alternative assumes the natural gas-fired electric generation facility would not include CO_2 capture or storage, EOR at the EHOF, or production of any fertilizer or other nitrogen-based products. It should be noted that an alternative considering a new or existing natural gas combined cycle facility capable of CO_2 capture and storage, as well as EOR at an existing oil field, remains under consideration by staff and is discussed below in the subsection “Alternative Still Under Consideration.”

Alternatives Table 5 provides an analysis of this alternative in comparison to the HECA project objectives.

Alternatives Table 5
Comparison of Natural Gas Project Alternative to HECA Project Objectives

HECA PROJECT OBJECTIVE	Meets Objective?	Consistency Analysis
Provide dependable, low-carbon electricity to help meet future power needs … (Note: HECA may not meet this	Yes	A Natural Gas Project Alternative would provide lower-carbon intensity electricity.

HECA PROJECT OBJECTIVE	Meets Objective?	Consistency Analysis
project objective.)		
… and to help back-up intermittent renewable power sources, to support a reliable power grid. (Note: HECA would not provide this project objective.)	Yes	A Natural Gas Project Alternative would provide dependable electricity and back-up intermittent power sources serving the grid.
Enhance the production and availability of in-state nitrogen-based products for use in agricultural, transportation, and industrial applications by producing approximately one million tons per year of low-carbon products, including urea, UAN, and anhydrous ammonia.	No	A Natural Gas Project Alternative absent a reformer added would not produce hydrogen that could be utilized in the production of nitrogen-based products. Therefore, a Natural Gas Project Alternative would not attain this project objective.
Conserve domestic energy supplies and enhance energy security by using abundant solid feedstocks, coal, and petroleum coke to generate electricity and manufacture low-carbon nitrogen based products.	No	A Natural Gas Project Alternative would not conserve domestic energy supplies (in the form of natural gas) nor utilize domestic solid feedstocks, coal, or petroleum coke to generate electricity. Furthermore, a natural gas electrical facility would not generate hydrogen and nitrogen that could be utilized in the production of nitrogen-based products. Therefore, a Natural Gas Project Alternative would not attain this project objective.
Mitigate impacts related to climate change by dramatically reducing average annual GHG emissions relative to those emitted from a conventional power plant and/or nitrogen-based product manufacturing facility by capturing, at a rate of at least 90 percent, and sequestering CO_2.	No	Within California, a Natural Gas Power Plant is considered a conventional power plant. As such, a Natural Gas Project Alternative could reduce GHG emissions toward mitigating impacts related to climate change relative to those emitted from any older (and dirtier) conventional power plant generation sources. Furthermore, a Natural Gas Project Alternative without CCS would emit less GHG/MWh than the HECA project. While natural gas plants can meet California's GHG Emission Performance Standard threshold without sequestration, a conventional natural gas electrical facility would not capture CO_2 for sequestration purposes nor generate hydrogen that could be utilized in the production of nitrogen-based products. Therefore, a conventional Natural Gas Project Alternative would not attain the whole of this project objective. Please refer to the subsection entitled "Alternatives Still Under Consideration" for the status of evaluating a natural gas with CCS alternative.
Use captured CO_2 for EOR to produce additional oil reserves.	No	A Natural Gas Project Alternative would not capture CO_2 for sequestration purposes, and therefore would not attain this project objective.
Demonstrate advanced solid fuel based technologies that can generate clean, reliable, and affordable electricity in the United States … (Note: HECA may not meet this project objective.)	No	A Natural Gas Project Alternative would not utilize advanced solid fuel based technologies. Therefore, a conventional Natural Gas Project Alternative would not attain this project objective. Please refer to the subsection entitled "Alternatives Still Under Consideration" for the status of evaluating a natural gas with CO_2 capture and storage alternative.
… and prove out carbon capture and sequestration as a viable method for reducing the carbon footprint of power generation and manufacturing. (Note: HECA would not meet this	No	A Natural Gas Project Alternative would not utilize capture CO_2 for sequestration purposes. Therefore, a conventional Natural Gas Project Alternative would not attain this project objective. Please refer to the subsection entitled "Alternatives Still Under Consideration" for the status of evaluating a natural gas with CO_2 capture and storage alternative.

HECA PROJECT OBJECTIVE	Meets Objective?	Consistency Analysis
project objective.)		
Facilitate and support the development of hydrogen infrastructure in California by supplementing the quantities of hydrogen available for future energy and transportation technologies.	No	A Natural Gas Project Alternative would not produce hydrogen that could be utilized for energy purposes. Therefore, a Natural Gas Project Alternative would not attain this project objective.
Minimize environmental impacts associated with the construction and operation of the project through technology selection, project design, and implementation of feasible mitigation measures, where necessary.	Yes	A Natural Gas Project Alternative could reduce GHG emissions toward mitigating impacts related to climate change relative to those emitted from any older (and dirtier) conventional power plant generation sources. While natural gas plants can meet California's GHG threshold without sequestration, a conventional natural gas electrical facility would likely result in similar or lower overall construction and operational impacts when compared to the HECA project at the same site. Therefore, a Natural Gas Project Alternative would attain this project objective.
Site the project at a location over which HECA LLC will have control, and which offers reasonable access to necessary infrastructure, including natural gas, process water supply, transmission and rail interconnection, and geologic formations appropriate for CO_2 EOR and sequestration.	Yes	The HECA site does offer reasonable access to necessary infrastructure. As such, this alternative would attain this project objective.
Ensure the economic viability of the project by integrating electricity production with the manufacture of multiple products to meet market demand. (Note: HECA may not meet this project objective.)	No	A Natural Gas Project Alternative would not produce hydrogen and nitrogen that could be utilized for electricity generation and production of fertilizer and other hydrogen based products. Therefore, a Natural Gas Project Alternative would not attain this project objective. However, a Natural Gas Project Alternative might not need the revenue stream from by-product sales to be financially viable.
Meet all requirements necessary to secure and retain DOE funding for the project.	No	Because there would be no coal involved in natural gas power generation, this alternative would not meet the DOE CCPI Program funding requirements or the DOE purpose and need for the HECA project. Therefore, a Natural Gas Project Alternative would not attain this project objective. However, a Natural Gas Project Alternative might not need the DOE funding to be financially viable.

A Natural Gas Project Alternative without carbon capture and storage would not meet a number of HECA project objectives (inconsistent with more than HECA). As such, a Natural Gas Project Alternative has been eliminated from further consideration (consistent with CEQA §15126.6[a]). However, a Natural Gas Project Alternative with Carbon Capture and Storage is discussed further under the subsection "Alternatives Still Under Consideration."

ENCLOSED GROUND FLARE AND FLARE RECOVERY SYSTEM ALTERNATIVE

Intervener Sierra Club requested the scope and content of this analysis include an Enclosed Ground Flare and Flare Recovery System Alternative instead of the elevated flares proposed by HECA. Sierra Club has indicated that the proposed flare system is inefficient and would result in increased air quality emissions compared to those of a possible Enclosed Ground Flare and Flare Recovery System Alternative. Staff has conducted an analysis assuming a ground level enclosed flare suggested by Sierra Club would be a thermal oxidizer. As provided in **Alternatives Appendix 1**, the following analysis was conducted in cooperation with Air Quality staff.

Overall, ground level enclosed flares would have lower volatile organic compounds (VOC), carbon monoxide (CO), and particulate matter (PM) emissions due to better combustion of most pollutants. However, sulfur oxide (SOx) emissions would be the same and nitrogen oxide (NOx) emissions would likely be higher. Overall, the emissions of the HECA flare system (while high for the short-term when the flares are running) are not significant over the long term. Furthermore, the short-term and long-term air quality impacts of the HECA flare system are low due to the high release height for these elevated flares and thermal buoyancy of the flares.

The cost and size of a ground level enclosed flare design for the HECA could affect the feasibility of using this alternative. Elevated flares, as designed for HECA, are typically used for larger volumes of gasses. As such, Air Quality staff concurs with the project applicant that the HECA project use an elevated flare because the project gasification flare is required to handle large volumes of off gasses. The cost to include a ground-level flare to address HECA's limited flaring events would be very high on a dollar/ton basis.

In addition to these constraints, elevated flares also have a simpler design, and therefore are more reliable than ground flares (HECA 2012x, Data Response 55). Additionally, elevated flares are inherently safer than ground flares because they are physically removed from the ground and are therefore not a danger to persons, buildings, or other structures on the ground. Also, ground flares rely on a refractory shell to separate persons or buildings on the ground from the heat released by the combustion of the flared gasses. Elevation of flares provides better dispersion of the flared gasses, protecting people on the ground, both within and outside the HECA site. No significant air quality impacts have been identified for use of elevated flares by HECA. Based on the discussion provided above, an Enclosed Ground Flare and Flare Recovery System Alternative would not avoid or substantially lessen any significant project-related air quality impacts (refer to **Alternatives Table 1**). Therefore, the Enclosed Ground Flare and Flare Recovery System Alternative has been eliminated from further consideration due to not avoiding or substantially lessening any significant project-related air quality impacts and for safety reasons.

REDUCED COAL/INCREASED PETCOKE UPON CONCLUSION OF FIVE-YEAR SECTION 48A PROGRAM REQUIREMENT PERIOD ALTERNATIVE

This alternative evaluates increasing petcoke and decreasing coal in the fuel blend after completion of the two-year demonstration phase requirement of utilizing 75 percent coal and five-year Section 48A program requirement. This alternative has the ability to reduce or lessen long-term impacts associated with the transport of coal to the HECA site from the source mine in New Mexico. These impacts include, but are not limited to, air quality emissions from transport uses, impacts to biological species during transport, and traffic impacts resulting from vehicle trips.

Overview

The applicant is the recipient of a $408 million CCPI Round 3 grant from DOE. The minimum requirement for coal use for projects selected by DOE in Round 3 of the CCPI grant program is 55 percent coal, with the main focus being on carbon capture technologies (HECA 2013n). The project applicant's specific Cooperative Agreement with the DOE requires that HECA use coal for at least 75 percent of the energy input for operations during the first two years of operations (HECA 2013n).

In addition to DOE funding, the project applicant is the recipient of approximately $103 million in Section 48A federal tax credits (HECA 2013n). The Section 48A program requires that qualifying projects use 75 percent coal for the first five years of operations (HECA 2013n). This alternative evaluates increasing petcoke use and decreasing coal in the fuel blend after completion of the Section 48A five year requirement of utilizing 75 percent coal.

The project applicant has also stated that the 75 percent coal and 25 percent petcoke fuel blend stems from technological requirements associated with the MHI gasifier after a thorough review of all commercially viable gasifier technologies (HECA 2013n). To date, the maximum performance guarantee the manufacturer is willing to provide the project applicant is a 75 percent coal 25 percent petcoke blend (HECA 2013n). This performance guarantee is required to obtain long-term financing (HECA 2013n). In addition, the project applicant has stated that coal procurement conforms to investor preferences as coal providers seek long term (typically 20+ years) supply contracts enabling them to recoup the high capital outlays associated with mine development (HECA 2013n).

Gasifier Technology

MHI technology forms the HECA project selection for IGCC. Alternative gasification and hydrogen electrical generating equipment that could be utilized by HECA has been evaluated in Section 6.0 of the 2008 AFC, 2009 Revised AFC, and 2012 Amended AFC. Other gasification technology options were considered, including those of GE, Shell, and ConocoPhillips. The use of the Mitsubishi IGCC technology was selected for HECA to generate low-carbon power using hydrogen-rich fuel produced from a solid feedstock (HECA 2012e, Section 6.0). Other technologies such as pulverized coal technology and oxyfuel technology were briefly analyzed but would not meet carbon capture goals, were environmentally inferior (lower efficiency, higher water usage, and higher emissions), or were an unproven technology at the HECA project scale (HECA 2012e, Section 6.0).

The MHI gasifier has the theoretical capability to achieve feedstock flexibility similar to that of the previously proposed General Electric (GE) slurry fed refractory lined gasifier, which was the technology included within the original HECA project filing in 2008 (HECA 2013n). While the General Electric gasifier had the ability to operate with 100 percent petcoke and support flexibility to operate with up to 60 percent coal (HEI 2008a), the MHI gasifier technology is designed to improve efficiency with a dry feed system, and improve reliability with a membrane wall and slagging ash removal. Staff agrees that the MHI gasifier design is the likely direction of solid fuel gasification and CCS projects, despite current HECA limits on coal/pet coke blends.

Actions Associated With the Reduced Coal/Increased Petcoke Upon Conclusion Of The Five-Year Section 48a Program Requirement Period Alternative

This alternative assumes that to reduce coal use after completion of either two-years or five-years of operations, the HECA project owner would:

- Operate the proposed gasifier at a different coal/petcoke blend; or
- Replace the gasifier with one similar or identical to that proposed within the 2008 Revised AFC, which could operate with 100 percent petcoke and support flexibility to operate with up to 60 percent coal (HEI 2008a).

Ability to Meet HECA Project Objectives

Alternatives Table 6 provides information on how this alternative would meet HECA project objectives. Kern County Planning and Community Development Department, public, and intervener comments requested the scope and content of this analysis include an alternative that would reduce coal use and transport. As such, staff further evaluated a Reduced Coal/Increased Petcoke Alternative.

Alternatives Table 6
Comparison of Reduced Coal/Increased Petcoke Alternative to HECA Project Objectives

HECA PROJECT OBJECTIVE	Meets Objective?	Consistency Analysis
Provide dependable, low-carbon electricity to help meet future power needs … (Note: HECA may not meet this project objective.)	No	Reducing the percentage use of coal in HECA's fuel blend after the five-year Section 48A Program requirement period would not affect HECA's inability to produce dependable low-carbon electricity.
… and to help back-up intermittent renewable power sources, to support a reliable power grid. (Note: HECA would not meet this project objective.)	No	Reducing the percentage use of coal in HECA's fuel blend after the five-year Section 48A Program requirement period would not affect HECA's inability to back-up intermittent renewable power sources.
Enhance the production and availability of in state nitrogen-based products for use in agricultural, transportation, and industrial applications by producing approximately 1 million tons per year of low-carbon products, including urea, UAN, and anhydrous ammonia.	Yes	Reducing the percentage use of coal in the HECA project fuel blend after the five-year Section 48A Program requirement period would not impact the HECA project's ability to produce nitrogen-based products.
Conserve domestic energy supplies and enhance energy security by using abundant solid feedstocks, coal, and petroleum coke to generate electricity and manufacture low-carbon nitrogen based products.	Yes	Reducing the percentage use of coal in HECA's fuel blend after the five-year Section 48A Program requirement period would not significantly impact HECA's ability to conserve domestic energy supplies and enhance energy security by using petroleum coke (and to some extent coal) to generate electricity.
Mitigate impacts related to climate change by dramatically reducing	Yes	Reducing the percentage use of coal in HECA's fuel blend after the five-year Section 48A Program

HECA PROJECT OBJECTIVE	Meets Objective?	Consistency Analysis
average annual GHG emissions relative to those emitted from a conventional power plant and/or nitrogen-based product manufacturing facility by capturing, at a rate of at least 90 percent, and sequestering CO_2.		requirement period would not impact HECA's ability to mitigate GHG emissions when compared to a conventional power plant and would not impact the ability for CO_2 capture and sequestration by HECA.
Use captured CO_2 for EOR to produce additional oil reserves.	Yes	Reducing the percentage use of coal in HECA's fuel blend after the five-year Section 48A Program requirement period would not affect HECA's ability for CO_2 capture, sequestration and EOR.
Demonstrate advanced solid fuel based technologies that can generate clean, reliable, and affordable electricity in the United States … (Note: HECA may not meet this project objective.)	Yes	Reducing the percentage use of coal in HECA's fuel blend after the five-year Section 48A Program requirement period would not affect HECA's ability to demonstrate advanced solid fuel based technologies for low-carbon electrical generation or impact CO_2 capture and sequestration.
… and prove out carbon capture and sequestration as a viable method for reducing the carbon footprint of power generation and manufacturing. (Note: HECA would not meet this project objective.)	No	HECA has not shown that it would reduce the carbon footprint of power generation facilities likely to be located in California. Reducing the percentage of coal in HECA would not change this conclusion.
Facilitate and support the development of hydrogen infrastructure in California by supplementing the quantities of hydrogen available for future energy and transportation technologies. (Note: HECA would not meet this project objective.)	No	Reducing the percentage use of coal in HECA's fuel blend after the five-year Section 48A Program requirement period would not affect the project's ability to generate hydrogen and facilitate/support the development of hydrogen infrastructure in California.
Minimize environmental impacts associated with the construction and operation of the project through technology selection, project design, and implementation of feasible mitigation measures, where necessary.	Yes	Reducing the percentage use of coal in the HECA project fuel blend after the five-year Section 48A Program requirement period would lessen environmental impacts associated with the transport of coal to the project site.
Site the project at a location over which HECA LLC will have control, and which offers reasonable access to necessary infrastructure, including natural gas, process water supply, transmission and rail interconnection, and geologic formations appropriate for CO_2 EOR and sequestration.	Yes	Reducing the percentage use of coal in the HECA project fuel blend after the five-year Section 48A Program requirement period would not impact the HECA project's ability to site this alternative within the HECA project site and utilize proposed linear infrastructure.
Ensure the economic viability of the project by integrating electricity production with the manufacture of multiple products to meet market demand. (Note: HECA may not meet this project objective.)	Possibly	Reducing the percentage use of coal in HECA's fuel blend after the five-year Section 48A Program requirement period would not affect the project's ability to produce hydrogen for use in producing nitrogen-based products.
Meet all requirements necessary to secure and retain DOE funding for	Yes	This alternative would reduce the percentage use of coal in the HECA project fuel blend after fulfillment of the two-

HECA PROJECT OBJECTIVE	Meets Objective?	Consistency Analysis
the project.		year DOE demonstration period. As such, it would not conflict with DOE's CCPI Program requirements.

Feasibility

Energy Commission engineering staff have evaluated the feasibility of this alternative. In response to a staff data request, the project applicant reiterated a long-term commitment to the 75/25 mix under the condition that they "retain the capability to run more than 25 percent petroleum coke (petcoke), either for economic reasons or in response to fuel supply disruptions" (HECA 2012q). The project applicant restated this position in their response to questions raised at the January 16, 2013 Status Conference, citing the lack of commercial operating experience at varied feedstock blends, specifically stating (HECA 2013n):

- "The MHI gasifier has the theoretical capability to achieve feedstock flexibility similar to that of the previously proposed General Electric refractory lined gasifier; however, more operating experience is necessary to determine whether this theoretical capability can be fully realized."
- "Demonstration (of petcoke) at scale must be incorporated into the experience base of MHI before the full range of feedstock flexibility can be determined and guarantees can be made."
- "In sum, from an investor's prospective, the use of petcoke as a feedstock is less desirable than coal due to a perceived increased risk of supply disruption."

Based upon engineering staff review and analysis, unless and until the Mitsubishi power block and gasifier can be shown to have feedstock flexibility and commercial viability, modifying the existing system is not a reasonable alternative. Among the major manufacturers that offer a pairing of fuel gasification with a combined cycle (IGCC), only GE has a commercial track record with varying the feedstock blends of coal and petcoke. GE utilizes an entrained flow gasifier originally developed by Chevron-Texaco (Breault 2010). Given the limitation of current commercial scale knowledge, the case for adjusting feedstock blends in response to market availability is not an inevitable outcome. The cost benefit of securing long-term fuel contracts for the life of the facility at the 75/25 coal to petcoke fuel mix would have to be weighed against impacts of:

- Cost of design and development of a system consisting of a manufacturing hybrid, i.e. GE and Mitsubishi;
- Lost electrical power production in Year 6 in order to make the necessary plant modifications;
- Lost product production with the temporary shutdown of the ammonia manufacturing facility; and
- Interruption and potential loss of the enhanced oil recovery (EOR) system, which is dependent upon the generation and transmission of carbon dioxide (CO_2).

Engineering staff evaluation of this alternative also included review and analysis of the following items:

- Feasibility of MHI System to Accommodate Variable Fuel Blend: MHI has no commercial track record on the use of liquid petroleum refining by-products with its gasifier beyond the commitment to provide reliable operation at the 75 percent coal and 25 percent petcoke fuel blend.
- Maximum Petcoke Blend Ratio During Demonstration Period: The MHI gasifier is an entrained flow gasifier co-developed jointly with Combustion Engineering. It is a dry feed system for low rank coals having high moisture content, demonstrated at a plant started up in 2007 in Nakoso, Japan. Beyond the commitment by MHI to guarantee performance at 75/25, MHI has no track record with coal and liquid petroleum refinery by-products blends (Breault 2010). Without further demonstration, the safe and acceptable range of fuel blends beyond 75/25 is unknown.
- Design Requirements to Replace Gasifier: It is unlikely that the replacement of a single component would be sufficient to maintain the chemical and energy equilibrium of the existing HECA system. Achieving equilibrium would require modifications of all the intermediate processes including conversion of feedstock blend to a hydrogen gas fuel, removal of sulfur and other solid constituents from the raw fuel mix, operation of a proprietary method for acid gas removal (Rectisol), and the carbon dioxide transmitted to the enhanced oil recovery system. The design effort to evaluate and modify the changes would be concomitantly significant.
- Impact of Gasifier Modification to Fertilizer Manufacturing Output: The most obvious effect on the fertilizer manufacturing facility would be the disruption of product production during the shutdown time required to modify the gasification system.
- Cost to Replace Gasifier: Staff is currently unable to determine this.
- Adequacy of Petcoke Feedstock Within California Operating at 100 Percent Petcoke: The HECA applicant estimated that, at the fuel blend using 25 percent petcoke, HECA would consume 1,140 short tons per day (stpd), 400,000 short tons per year (sty) or about 7 percent of the total in-state production (HECA, 2012e, p. 2-16). If the petcoke consumption quadrupled to 100 percent, the consumption of the available petcoke inventory would increase by four times (4x) to 28 percent. This is a significant increase.

Energy Commission Staff Conclusion

Independent staff review of general information regarding IGCC technology corroborates information reviewed and assessed for the specific conditions of the HECA project:

1. The loss of power and fertilizer production would cause an interruption in providing service reliably.
2. Without commercial operating experience, the option to vary the feedstock blends is not a legitimate alternative.
3. More effort would be involved in implementing the above modifications than the simple replacement of the MHI gasifier furnished in the design outlined in the Amended AFC (2012) and subsequent written correspondence with the project applicant on this subject (HECA 2013n).

This alternative has the ability to lessen or avoid long-term impacts associated with coal transport and operation of HECA and would achieve a similar number of the project objectives when compared to HECA. However, staff's analysis shows that the Reduced Coal/Increased Petcoke Upon Conclusion Of The Five-Year Section 48a Program Requirement Period Alternative would be technologically infeasible.

ALTERNATIVES STILL UNDER CONSIDERATION

This section briefly discusses known alternatives still under consideration by Energy Commission staff. Some of these will also be considered by DOE as part of the NEPA process. Analysis of these alternatives will be provided in the FSA/FEIS. It should be noted that the alternatives still under consideration will be evaluated in the FSA/FEIS as either feasible (and evaluated in detail) or infeasible (and eliminated from further evaluation).

For a description of water supply alternatives to be evaluated within the FSA/FEIS, please refer to the **Water Supply** section within this PSA/DEIS (Section 4.15).

The public and other interested entities are invited to comment on these alternatives and their feasibility.

DRY COOLING OR WET-DRY HYBRID COOLING ALTERNATIVE

Agency, public, and intervener comments requested the scope and content of this analysis include a Dry Cooling or Wet-Dry Hybrid Cooling Alternative. The project applicant has indicated that output, cost, and efficiency penalties associated with using only air cooling are much more significant for the HECA project than for a typical natural gas combined cycle (NGCC) project because for an NGCC, the efficiency impact is confined to the steam turbine; whereas in the HECA process units (gasification, gas treatment, and manufacturing complex), the impacts occur to many pieces of equipment, most of which are significantly more sensitive to heat rejection temperature than a steam turbine (HECA 2012ll, Response A203). The applicant indicates that HECA would have cooling towers for the air separation unit, the power block and the gasifier processes.

The project applicant has stated that the efficiency loss (increase in auxiliary load) and capital cost impacts associated with implementing air cooling in the process portion of the plant makes this alternative infeasible with no real benefit (HECA 2012ll, Response A203). Based on its research, the applicant has stated the selection of an air-cooled process would result in the following (HECA 2012ll, Response A203):

- Capital cost differential of approximately $20-30 million;
- Reduced power output of between 20 to 40 megawatts (MW); and
- Overall total cost impact of about $50 million.

At the time of the PSA/DEIS publication, Water Supply staff is unable to determine if Dry Cooling or Wet-Dry Hybrid Cooling Alternative is feasible and has the potential to reduce significant water use impacts. Therefore, a Dry Cooling or Wet-Dry Hybrid Cooling Alternative will be evaluated in the FSA/FEIS to determine if it can reduce

HECA's water consumption. For a further discussion of the Dry Cooling or Wet-Dry Hybrid Cooling Alternative, please refer to the **Water Supply** section within this PSA/DEIS (Section 4.15). DOE believes that is a project-level alternative that merits further analysis and consideration.

NATURAL GAS COMBINED CYCLE WITH CARBON CAPTURE AND STORAGE (CCS)

As described in the subsection "Alternatives Eliminated From Detailed Consideration," staff has eliminated the Natural Gas Project Alternative which consists of a conventional natural gas-fired electric generation facility that would generate electricity but would not include CO_2 capture or storage, EOR at the Elk Hills Oil Field, or production of any fertilizer or other nitrogen-based products.

To conduct a thorough and robust alternatives analysis, staff is considering an alternative that would consist of a natural gas combined cycle electrical generation facility capable of carbon capture and storage (CCS) for EOR at the Elk Hills Oil Field. This alternative includes the possible development of a new natural gas combined cycle facility (either at the HECA site or another site). Engineering staff considers that CCS coupled with natural gas power plants should be evaluated, especially when looking to the future as easily dispatchable natural gas capacity is expected to be used to back up intermittent renewable energy sources, not base-loaded coal facilities. Additionally, many depleted oil fields that are the targets of CCS deposits and EOR are within California.

Staff acknowledges that many HECA project objectives are linked to coal/petcoke gasification for electrical production, CCS, and production of fertilizer and other nitrogen-based products. Staff also acknowledges the issue of losing project funding resulting from implementation of a natural gas combined cycle with CCS Alternative versus the HECA project is an important consideration, as it would eliminate coal-fueled electricity production (a requirement for DOE funding and section 48a tax credits) from the project while still demonstrating CCS and EOR at the EHOF. Additionally, to separate carbon dioxide from the other constituents inherent in natural gas combustion versus combustion of hydrogen derived from gasification of coal/petcoke, this alternative may require different above-ground components than those associated with the HECA project. For example, a steam reformer may be needed to produce hydrogen-rich fuel in place of the coal/pet coke gasification system, if the objective is to capture carbon before combustion and/or to incorporate fertilizer production into the project. The cost of the natural gas system should be compared to the cost of the coal/pet coke system (including gasifier, air separation unit, coal/pet coke delivery and storage onsite) and the difference in cost should be compared to the DOE funding and section 48a tax credits that would be lost. Furthermore, the differential cost between coal/pet coke and natural gas would need to be included for a more complete cost comparison. Finally, at the quantity of carbon dioxide proposed by HECA to be sequestered, a natural gas system with CCS is likely to be able to generate more new incremental MW capacity than HECA's net incremental MW capacity that would be added to the grid. This result is expected because natural gas has approximately half the carbon per BTU than does coal.

As this alternative would not require the transport and use of coal and petcoke feed stocks, as well as transport of nitrogen based products, the environmental benefits of this alternative would be to lessen or avoid adverse impacts (Air Quality, Transportation/Traffic, Biological Resources) associated with these HECA project features. Please refer to all relevant environmental issue area analyses (refer to Section 4 of this PSA/DEIS).

This alternative is not a reasonable one for DOE's purpose and need. DOE's authority to provide financial assistance is limited to projects that use coal. This is an example of a situation in which there is a divergence of alternatives under CEQA and NEPA.

BIOMASS BOILER ALTERNATIVE

Staff is considering an alternative that would consist of a biomass-fired boiler that would provide the same net new electrical capacity and energy as HECA. This alternative may not provide carbon capture and storage, but would provide a new, local renewable energy facility with essentially a zero-carbon footprint, depending on how far the biomass would have to be transported to the facility site. There is at least one existing biomass-fired boiler in Kern County, which recently converted from coal. The availability of biomass to fuel a new boiler in southern San Joaquin Valley has yet to be evaluated. It should also be noted that this alternative was requested by Sierra Club, as identified in the subsection "Public and Agency Participation."

This alternative is not a reasonable one for DOE's purpose and need. DOE's authority to provide financial assistance is limited to projects that use coal. This is an example of a situation in which there is a divergence of alternatives under CEQA and NEPA.

ADDITIONAL ALTERNATIVE SITES

Alternative sites evaluated in the subsection "Alternatives Eliminated From Detailed Consideration" focused on locations proximate to the EHOF. Public comments provided at the San Joaquin Valley Air Pollution Control District (SJVAPCD) Preliminary Determination of Compliance public workshop on April 2, 2013 for the HECA project included a request that Energy Commission staff evaluate alternative sites for the HECA project located up to 200 miles from the proposed site, with the project including an expansive CO_2 pipeline to the EHOF for EOR. Due to the timing of this comment and the size and scale of this request, staff was unable to consider this alternative prior to publication of this PSA/DEIS. Staff's preliminary review has shown power plant facilities within the United States successfully demonstrating CCS with CO_2 pipelines over 200 miles long providing EOR. For example, the Great Plains Synfuels Plant near Beulah, North Dakota transports CO_2 via a 205-mile pipeline to an oil field near Weyburn, Saskatchewan, Canada for EOR. This alternative will be considered within the FSA/FEIS.

This alternative is not a reasonable one for DOE's purpose and need. DOE's authority to provide financial assistance using monies appropriated by the Recovery Act prohibits changes in the project's scope (including significant location changes) after September 20, 2010. Also, the applicant has invested significant financial resources in obtaining the option to purchase the site, and would be unable or unwilling to move the project at this late date. This is another example of a situation in which there is a divergence of alternatives under CEQA and NEPA.

COAL TRANSFER ROUTE ALTERNATIVES

The HECA project includes both rail and truck options for coal delivery from the rail transfer point. These options are analyzed in the **Traffic and Transportation** and **Land Use** sections of this PSA/DEIS. With respect to alternative rail and truck routes, each proposed route option was selected to utilize existing rail and roadways, minimize travel distance, and minimize any potential ground disturbance activities. As discussed in the **Biological Resources** section of this PSA/DEIS, the proposed project would result in potentially significant impacts to San Joaquin kit fox as a result of fox being run over by trucks. At present, an adequate mitigation proposal has not been received. At this time, creation of new coal transport rights-of-way or longer travel distances for coal via rail or truck are not known to lessen or avoid any impacts associated with the coal transport options being evaluated. Alternatives staff will continue to coordinate with Biological Resources staff to determine if alternative truck routes may be developed for the FSA/FEIS. At this time, therefore, alternative coal transport routes were not developed by staff and may be evaluated or eliminated from consideration in the FSA/FEIS. DOE believes that is a project-level alternative that merits further analysis and consideration.

ALTERNATIVES EVALUATED IN DETAIL

An analysis comparing the environmental effects of HECA to each of the project alternatives warranting detailed evaluation is provided below. The project action alternatives evaluated in detail meet the alternatives screening requirements discussed earlier in the subsection “CEQA Requirements.” **Alternatives Table 7** provides a summary of each alternative’s ability to fulfill project objectives.

Following an overview of each alternative, an environmental analysis by resource area is provided for each alternative. The analysis is focused on the ability of the alternative to avoid or lessen any significant project impacts (as identified within **Alternatives Table 1**). **Alternatives Appendix 1** contains a list of staff contributors to the environmental analysis of alternatives evaluated in detail.

Alternatives Table 7
Summary Comparison of Alternatives Evaluated in Detail to Project Objectives

Project Objective	No Project Alternative (CEQA) No Action Alternative (NEPA)	No Fertilizer Manufacturing Complex (Reduced Project) Alternative
Provide dependable, low-carbon electricity to help meet future power needs … (Note: HECA would not meet this project objective.)	No. Under the No Project Alternative, no electricity would be produced by the HECA project.	Potentially. If HECA is constructed and attains mature operations, it would demonstrate that coal facilities could be carbon-equivalent to natural gas facilities
… and to help back-up intermittent renewable power sources, to support a reliable power grid. (Note: HECA would not meet this project objective.)	No. HECA could not back up intermittent renewable power sources.	Under the No Fertilizer Manufacturing Complex (Reduced Project) Alternative, without the fertilizer manufacturing complex the facility would have less ability to ramp up and down by approximately 114 megawatts.
Enhance the production and availability of in state nitrogen-based products for use in agricultural, transportation, and industrial applications by producing approximately 1 million tons per year of low-carbon products, including urea, UAN, and anhydrous ammonia.	No. Under the No Project Alternative, no nitrogen-based products would be produced by the HECA project. Pet coke would continue to be exported to other countries for their use (with associated GHG emissions).	No. Under the No Fertilizer Manufacturing Complex (Reduced Project) Alternative, no nitrogen-based fertilizer products would be produced by HECA.
Conserve domestic energy supplies and enhance energy security by using abundant solid feedstocks, coal, and petroleum coke to generate electricity and manufacture low-carbon nitrogen based products.	No. The No Project Alternative would not produce electricity or nitrogen based products. However, the facility would have less ability to ramp up and down by approximately 114 megawatts.	No. While this alternative would enhance energy security by using petcoke and coal to generate electricity, no nitrogen-based fertilizer products would be produced under the No Fertilizer Manufacturing Complex (Reduced Project) Alternative.
Mitigate impacts related to climate change by dramatically reducing average annual GHG emissions relative to those emitted from a conventional power plant and/or nitrogen-based product manufacturing facility by capturing, at a rate of at least 90 percent, and sequestering CO_2.	No. While the No Project Alternative would not generate any GHG emissions, no nitrogen-based products would be produced and no CO_2 sequestration by HECA would occur.	**Yes.** Under the No Fertilizer Manufacturing Complex (Reduced Project) Alternative, no nitrogen-based fertilizer products would be produced by HECA, which would reduce air quality emissions from transporting fertilizer products produced by the project. Furthermore, this alternative would not impact the ability for CO_2 capture and sequestration by the HECA project.
Use captured CO_2 for EOR to produce additional oil reserves.	No. Under the No Project Alternative, no CO_2 sequestration for EOR would occur by HECA.	**Potentially**. The No Fertilizer Manufacturing Complex (Reduced Project) Alternative would not affect the ability for CO_2 capture, sequestration and EOR by the HECA project. However, HECA has not shown that their project would produce oil reserves that could not otherwise be produced by other means.
Demonstrate advanced solid fuel based technologies that can generate clean, reliable, and affordable electricity in the United States …	No. Under the No Project Alternative, no electricity or carbon capture would be created by HECA.	**Potentially**. The No Fertilizer Manufacturing Complex (Reduced Project) Alternative would not impact the ability of the HECA project, if it reaches

Project Objective	No Project Alternative (CEQA) No Action Alternative (NEPA)	No Fertilizer Manufacturing Complex (Reduced Project) Alternative
(Note: HECA may not meet this project objective.)		mature operations, to generate low-carbon electricity utilizing solid fuel based technologies or impact CO_2 capture and sequestration, assuming project financing was not adversely affected. If HECA is constructed and attains mature operations, it would demonstrate that coal facilities could be carbon-equivalent to natural gas facilities. However, the applicant has not shown that the electricity produced by HECA would be priced at a low enough price to meet their stated annual hours of operation and at a high enough price to make their facility operate reliably.
… and prove out carbon capture and sequestration as a viable method for reducing the carbon footprint of power generation and manufacturing. (Note: HECA would not meet this project objective.)	No. Under the No Project Alternative, no carbon capture and sequestration would be included as a means of reducing the carbon footprint of power generation and manufacturing.	No. HECA has not shown that its facility would reduce the carbon footprint of power generation facilities likely to be located in California.
Facilitate and support the development of hydrogen infrastructure in California by supplementing the quantities of hydrogen available for future energy and transportation technologies. (Note: HECA would not meet this project objective.)	No. Under the No Project Alternative, no hydrogen infrastructure would be developed by HECA.	No. HECA has not shown that their facility would facilitate development of hydrogen infrastructure in California.
Minimize environmental impacts associated with the construction and operation of the project through technology selection, project design, and implementation of feasible mitigation measures, where necessary.	**Yes.** Under the No Project Alternative, none of the environmental impacts associated with HECA would occur.	**Yes.** Under the No Fertilizer Manufacturing Complex (Reduced Project) Alternative, no nitrogen-based fertilizer products would be produced by the project, which would reduce significant solid waste impacts associated with HECA.
Site the project at a location over which HECA LLC will have control, and which offers reasonable access to necessary infrastructure, including natural gas, process water supply, transmission and rail interconnection, and geologic formations appropriate for CO_2 EOR and sequestration.	No. Under the No Project Alternative, the HECA project would not be built.	**Yes.** Under the No Fertilizer Manufacturing Complex (Reduced Project) Alternative, the proposed fertilizer complex would not be built, and the project's ability to site this alternative within the HECA project site and utilize proposed linear infrastructure would not be significantly affected.
Ensure the economic viability of the project by integrating electricity production with the manufacture of multiple products to meet market demand. (Note: HECA may not meet this project objective.)	No. Under the No Project Alternative, the HECA project would not be built.	No. Under the No Fertilizer Manufacturing Complex (Reduced Project) Alternative, no nitrogen-based fertilizer products would be produced by the HECA project. The project is likely to be less financially viable if no fertilizer is manufactured.
Meet all requirements necessary to secure and retain DOE funding for the project.	No. Under the No Project Alternative, the HECA project would not be built.	**Yes.** Under the No Fertilizer Manufacturing Complex (Reduced Project) Alternative, the proposed fertilizer complex would not be built.

Project Objective	No Project Alternative (CEQA) No Action Alternative (NEPA)	No Fertilizer Manufacturing Complex (Reduced Project) Alternative
		However, the elimination of this facility would not conflict with DOE CCPI Program requirements.

NEPA NO ACTION ALTERNATIVE

Environmental Analysis

The analysis of the impacts of NEPA's No Action Alternative is contained within each environmental issue area section of this PSA/DEIS. Under the No Fund (NEPA No Action) Alternative, DOE would not provide financial assistance to the applicant for the HECA project. The applicant could still elect to construct and operate its project in the absence of financial assistance from DOE, but DOE believes this is unlikely. For the purposes of analysis in the PSA/DEIS, DOE assumes the project would not be constructed under the No Action Alternative.

CEQA NO PROJECT ALTERNATIVE

Overview

While the No Project Alternative would be inconsistent with all but one HECA project objective (refer to **Alternatives Table 7**), this analysis evaluates the No Project Alternative to the HECA project to fulfill Energy Commission requirements under CEQA §15126 and DOE's obligation to analyze a No Action Alternative under NEPA (40 C.F.R. § 1502.14(d)). As described in Section 6.2 of the Amended AFC (2012), under the No Project Alternative, HECA would not receive authorization from the Energy Commission to construct and operate a low-carbon IGCC polygeneration facility. As a result, under the No Project Alternative, the HECA project would not be developed (HECA 2012ll, Response A201).

Environmental Analysis

Air Quality

There would be no direct, localized emission changes to the SJVAPCD under the No Project Alternative. Therefore, there would be no direct impacts related to air quality and no mitigation agreements would be required under the No Project Alternative.

Biological Resources

HECA and its associated linear facilities are located in a rural, agricultural setting. Under the No Project Alternative, staff assumes most of the project area would remain in active agriculture. No natural allscale scrub habitat would be converted to agriculture for the project's associated transmission lines and linears. Agriculture is a land use that is relatively non-compatible with most terrestrial wildlife and special-status plant species that occur in the project area. Under the No Project Alternative, direct and indirect sources of biological impacts would remain at current levels including habitat disturbance, traffic, air emissions, ambient noise and lighting sources. Biological effects associated with implementation of the proposed project would not occur and the biological baseline would remain relatively unchanged. Staff also assumes under the No Project Alternative, that the Occidental CO_2 EOR project would not be implemented, and there would be few changes to the current impacts to special-status plant and wildlife species as a result of oil and gas activities on the EHOF. Therefore, the current endangered species permitting and mitigation strategy for ongoing oil and gas activities on EHOF would also remain in effect under the No Project Alternative and the biological baseline on EHOF would remain relatively unchanged. In summary, the potential for impacts to biological resources under the No Project Alternative would be less than those under the HECA project.

Carbon Sequestration and Greenhouse Gas Emissions

There would be no direct greenhouse gas emissions and there would be no carbon sequestration under the No Project Alternative. Therefore, no impacts would occur related to greenhouse gas emissions, climate change, and there would be no geologic or other impacts related to carbon sequestration under the No Project Alternative.

While the No Project Alternative would not result in direct emissions of greenhouse gases, other sources of these would continue to operate. Other less efficient or more CO_2-emitting power and fertilizer plants might be constructed in its place or existing plants might be operated more, thereby increasing their CO_2 emissions,

Domestically produced oil, with or without EOR, reduces CO_2 emissions caused by the transportation of foreign oil into the United States. The average distance of "water carrier" transport of imported oil is estimated at 4,300 miles/barrel (bbl). The CO_2 equivalent emissions associated with this transport are estimated at approximately 12 pounds of CO_2 per barrel of foreign oil transported to refineries in the United States. Based on the estimated increased production of domestic oil resulting from the use of the project's CO_2 for EOR at the OEHI (4,500 to 22,500 bbl/day), HECA could result in a CO_2 reduction of 10,000 to 49,000 tons/yr. This potential reduction in CO_2 would not be realized under the No Project Alternative.[3]

Similarly, under the No Action Alternative, there would be no production of urea or other nitrogenous compounds. HECA is estimated to generate 550,000 tons/yr of pelletized urea. Presently, all of the urea consumed in California's Central Valley is produced outside of California. Accordingly, the No-Project Alternative would require California to continue to import 100 percent of its urea, resulting in CO_2 from its transportation. Unlike the urea produced by HECA, it is likely that this imported urea is produced by facilities that do not capture and sequester their CO_2 emissions.

Finally, the No Project Alternative would not present the opportunity to demonstrate carbon capture and sequestration at a commercial scale.

Cultural Resources

Under the No Project Alternative, the current mix of land use practices in the project area of analysis/area of potential effects (PAA/APE) would continue (refer to the **Cultural Resources** section of this PSA/DEIS, Section 4.4, subsection "Project Area of

[3] Variations in crude oil and relationships of supply and demand are not reflected in these numbers. Numbers calculated using DOE-NETL's UpStreamDashBoard_v2.0.3 (DOE 2013) available at http://www.netl.doe.gov/energy-analyses/refshelf/PubDetails.aspx?Action=View&PubId=439

Analysis and Area of Potential Effects"). For the HECA site, controlled area, associated linears, and CO_2 pipeline north of the California Aqueduct, lands within the PAA/APE would remain in agricultural production and water conveyance. For the proposed CO_2 pipeline south of the California Aqueduct and EOR project elements, lands within the PAA/APE would be subject to maintenance of water conveyance structures, grazing, and oil production. The proposed EOR project elements would remain in oil production. Each of these types of activities would entail ground disturbance: disking and deep-ripping fields, off-pavement vehicular traffic, the passage of cattle, road maintenance and development, and well drilling and maintenance.

Although ground disturbance would continue under the No Project Alternative and result in impacts to surface archaeological resources identified in **Cultural Resources Table 8**, these impacts would occur at current intensity and generally at shallower depths than under the HECA project. The No Project alternative would result in impacts less severe than those of the HECA project. However, staff cannot currently assess the significance of impacts on buried archaeological resources in the PAA/APE or surface archaeological resources in the proposed EOR area; therefore, the significance of ground-disturbing impacts on buried archaeological resources in the PAA/APE and surface archaeological resources in the EOR area under the No Project Alternative is unknown.

Under the No Project Alternative, the only reasonably foreseeable impacts on significant historic built environment resources (Old Headquarters Weir and California Aqueduct) would be alteration of the structures for maintenance purposes. The significance level of impacts on these two cultural resources would be similar (less than significant).

Staff cannot currently assess the significance of impacts on historic built environment resources in the proposed EOR area. Therefore, the significance of impacts on historic built environment resources in the proposed EOR area under the No Project Alternative is unknown.

Geology and Paleontology

HECA is located in an active geologic area of the southern Great Valley geomorphic province in western Kern County, California. Because of its geologic setting, the site could be subject to moderate to high levels of earthquake-related ground shaking. Significant thicknesses of expansive clay soils are also present at the surface.

There are no known viable geologic or mineralogical resources at the site, with the exception of the oil and gas fields of the Naval Petroleum Reserve. Paleontological resources have been documented regionally within Quaternary alluvium and Tertiary Tulare Formation, similar to deposits that underlie the HECA site.

The No Project Alternative would not create a facility on the site and would therefore, not cause site grading or foundation construction that could disturb site soils that may potentially contain important fossils. Additionally, the absence of site development would preclude the erection of structures that could be susceptible to potential geologic hazards.

Therefore, the No Project Alternative would create no activities or objects that would increase impacts to geological or paleontological resources or be subject to geological hazards. Therefore, no impacts would occur related to geology and paleontology.

Hazardous Materials

Under the No Project Alternative, the need for hazardous materials management would be reduced to zero during either construction or operations. No hazardous materials would be transported to or from the facility, used at the site, or stored on the site. Therefore, no impacts would occur to the off-site public.

Land Use and Agriculture

No activities would impact land use or agricultural activities under the No Project Alternative. Therefore, no impacts would occur related to land use and agriculture.

Noise and Vibration

No activities that would increase noise or groundborne vibration levels above existing conditions would occur under the No Project Alternative. Therefore, no impacts would occur related to noise and vibration.

Public Health and Safety

Under the No Project Alternative, impacts on public health would be reduced to zero risk due to no exposure to toxic air contaminant during either construction or operations.

Socioeconomics

No activities that would impact socioeconomic resources would occur under the No Project Alternative. Staff notes that the No Project Alternative would eliminate any potential economic benefits that might otherwise result from HECA project construction and operation.

Soil and Surface Water

Under the No Project Alternative, continuing agricultural activities could cause potential soil erosion. The HECA project conservatively assumes that all 453 acres of the site would be disturbed during construction, which would be similar to the disturbance for the No Project Alternative, assuming agricultural activities would include a significant portion of the 453-acre site. However, construction of the HECA project would also include substantially more earthwork (such as excavation of unsuitable soil and construction of large berms), use of large construction equipment, and a larger number of active vehicles and personnel at the site. Although construction activities under the HECA project and agricultural activities under the No Project Alternative would both implement appropriate Best Management Practices (BMPs) to reduce the amount of soil erosion, staff believes that the No Project Alternative would have less impacts to soil erosion compared to the HECA project during construction due to the much larger amount of earthwork.

Conversely, the No Project Alternative would have greater impacts to soil erosion compared to the HECA project during operations, because ground disturbing activities would end after the HECA project is constructed and the site is stabilized. Ongoing farming activities would result in continued ground disturbance and potential soil erosion with the No Project Alternative. Furthermore, the HECA project would implement soil stabilizing measures (such as hydroseeding, paving, and gravel) to reduce erosion during operations.

The No Project Alternative does not include any of the facilities associated with the HECA project and there would be no impacts to water quality from the increase of impervious areas, operation of an industrial facility, or sanitary waste. As a result, these impacts under the No Project Alternative would be much less than the HECA project. In addition, because No Project Alternative does not include a CO_2 EOR component, all impacts associated with the CO_2 EOR facility would be much less than the HECA project. The No Project Alternative would generally maintain existing drainage patterns during times when rainfall produces runoff, allowing gradual sheet flow across agricultural land and into an onsite irrigation ditch, or to the site boundary and offsite. Although the increased impervious area of the HECA project could potentially increase the impacts of both onsite and offsite flooding, onsite retention basins would mitigate these impacts by directing flows away from proposed facilities and preventing the increased volume of runoff from flowing offsite. For this reason, staff believes that the potential impacts from onsite and offsite flooding of the No Project Alternative would be somewhat greater than the HECA project. During extremely large rain events (100-year storm or larger), some of the smaller unlined retention basins may overflow storm water runoff onto the site. The proposed berm located at the north border of the site could dam and redirect flow to cause localized flooding and erosion. For this situation, the No Project Alternative would be similar to the HECA project.

Assuming the No Project Alternative could potentially use pesticides or herbicides during agricultural activities, contaminated runoff could potentially impact water quality of offsite water resources (though BMPs could reduce these impacts). The HECA project would retain all wastewater and storm water runoff onsite, therefore the No Project Alternative would have somewhat greater potential impacts to water quality from contaminated runoff. The HECA project site is located outside the designated Federal Emergency Management Agency (FEMA) 100-year flood zone, the potential for the project to impede or re-direct expected 100-year flood flows would be less than significant. Therefore, these impacts under the No Project Alternative would be similar to the HECA project.

Traffic and Transportation

Activities that would increase traffic on the local roadway system above existing conditions and that would introduce a potential aircraft hazard (i.e., exhaust plumes) would not occur under the No Project Alternative. Therefore, no impacts would occur related to traffic and transportation.

Transmission Line Safety and Nuisance

With the No Project alternative, the field and non-field impacts from operating the project-related transmission lines would not occur. The field impacts would relate to the perceptible and non-perceptible field impacts described in staff's analysis as noise impacts, shock hazards, interference with radio-frequency communication, and fire hazards and human exposure to electric and magnetic fields. The noted hazard to area aviation would relate to the physical presence of the line itself. Although the proposed line design and operational plan would reduce these field and non-field impacts to levels of environmental insignificance, introduction of the line would generate such impacts in an area that would have been without them. The No Project Alternative would have no impacts in this area.

Visual Resources

The No Project Alternative would leave the site in a condition identical to its current state. The 453-acre project site is currently being used for farming purposes, including the cultivation of alfalfa, cotton, and onions. The No Project Alternative would eliminate the significant visual impact at KOP 1 (view of the HECA project site, looking west from Station Road), as this impact, resulting from the visual contrast and intrusion of the HECA project facilities, would not occur. Therefore, there would be no impacts to visual resources under present conditions compared to those of HECA.

Waste Management

Three Phase I Environmental Site Assessments (ESAs) and one Phase II ESA were completed for the HECA site. The last Phase I ESA was dated April 2012 and was prepared by URS for the 473-acre project site. The ESA was completed in accordance with the American Society for Testing and Materials Standard Practice E 1527-05 for ESAs. The December 2010 Phase II ESA, prepared by AECOM, was completed to evaluate the recognized environmental conditions (RECs) that were identified in the April 2009 and August 2010 HECA Phase I ESAs. A REC is considered to be the presence or likely presence of any hazardous substances or petroleum products on a property under the conditions that indicated an existing release, past release, or a material threat of a release of any hazardous substance or petroleum products into structures on the property or in the ground, groundwater, or surface water of the property. Most of the RECs for this project are depicted in **Waste Management Figure 1** (refer to the **Waste Management** section of this PSA/DEIS). The RECs for the proposed project site include: five former underground storage tanks (USTs), unidentified concrete structures, a farm equipment wash pad, a former PO fertilizing manufacturing facility (PO), outdoor and indoor tailings piles of raw materials used by PO, PO East Sump, and a number of locations with stained surface soil (HECA 2012e, Appendix L).

Based on available information, the No Project Alternative consists of retaining the HECA site in its current condition. No action would be taken and no energy project would be constructed and operated on the site. No other use is reasonably foreseeable;

therefore, it is assumed that existing conditions would persist at the site absent the proposed project. The No Project alternative would not cause any waste management impacts on existing disposal facilities because no waste would be generated and there would be no disturbance of contamination on site that could impact human health and the environment.

Water Supply

Under the No Project Alternative, baseline conditions would conceivably persist at both the HECA site, the Buena Vista Water Storage District (BVWSD) proposed well field, and at the West Kern Water District (WKWD) well field. No other activities were identified for these locations if HECA were not to receive authorization for operation. An additional 7,500 acre-feet per year (AF/y) would not be extracted from the BVWSD well fields, 12 AF/y would not be extracted from the WKWD well fields, and no water would be extracted from the HECA site.

Impacts resulting from continuation of baseline conditions (No Project Alternative) would be much less than those identified in the **Water Supply** section of this PSA/DEIS (refer to Section 4.15) for the proposed project. The following impacts would potentially be lessened under the No Project alternative:

- Water level lowering in local well owner wells;
- Increased Kern County sub-basin groundwater overdraft;
- Potential impacts to the California Aqueduct from subsidence; and
- Potential degradation of groundwater quality from project pumping.

Worker Safety and Fire Protection

Under the No Project Alternative, impacts on worker safety would be reduced to zero due to no workers being exposed to an industrial environment during either construction or operations. Fire protection would not be needed if no construction or operation occurred and thus there would be no direct or cumulative impact on the Kern County Fire Department.

NO FERTILIZER MANUFACTURING COMPLEX (REDUCED PROJECT) ALTERNATIVE

Overview

While the No Fertilizer Manufacturing Complex (Reduced Project) Alternative would not meet a number of project objectives, this alternative was evaluated for its potential to avoid or substantially lessen significant environmental impacts. Additionally, both public and intervener comments requested the scope and content of this alternatives analysis include a No Fertilizer Complex (Reduced Project) Project Alternative. Therefore, this alternative is evaluated in detail.[4]

The applicant has stated, absent the fertilizer manufacturing complex, HECA would use the hydrogen it produces to generate electricity only (HECA 2012ll, Response A207). The project applicant has stated the prior HECA design, without the fertilizer manufacturing complex (2009 Revised AFC), was abandoned by the previous project owners, in part because it was not economically viable (HECA 2012ll, Response A207).

HECA has the ability to limit the amount of fertilizer produced (HECA 2012ll, Response A207). To evaluate the ability of this alternative to avoid or lessen significant impacts, the No Fertilizer Manufacturing Complex (Reduced Project) Alternative assumes complete elimination of the fertilizer manufacturing facility from the project. This alternative assumes the remaining HECA project facilities would be constructed as proposed within the same project site footprint, but absent the fertilizer complex and necessary infrastructure to serve fertilizer and other nitrogen-based product manufacture and distribution.

Energy Commission engineering staff made the following assumptions and observations regarding the No Fertilizer Manufacturing Complex (Reduced Project) Alternative:

- According to the applicant, the HECA gasifier only comes in one size. Therefore, the No Fertilizer Manufacturing Complex (Reduced Project) Alternative could operate the gasifier at 100 percent capacity with the same coal/petcoke tonnage input and the same ash output. This would hold the fuel delivery and ash removal trains/trucks at the same number. This would also mean that the No Fertilizer Manufacturing Complex (Reduced Project) Alternative would have more H2 to combust in the power block (as H2 can no longer be diverted to the fertilizer plant). This would require the power block to be bigger or run harder, both would increase water use in the cooling tower and also mean more ammonia deliveries for the SCR than ammonia tonnage the HECA project would get from the fertilizer plant. The No Fertilizer Manufacturing Complex (Reduced Project) Alternative would also not have H2 storage on site, so this alternative must burn the excess H2 as it is made.

- Gasifiers (and most solid fuel power plants) are not as flexible as gas plants. They are much easier to operate and maintain if they are operated at a steady state. Once these plant types are brought to a steady fuel input rate state, their H2 output to the CTCC is also fairly fixed.

- Alternatively, under the No Fertilizer Manufacturing Complex (Reduced Project) Alternative, the applicant could buy the same gasifier and only operate it at 75 percent of its rated capacity. This would lower the fuel delivery and ash removal trains/trucks. However, staff does not know if the gasifier can turndown that much

[4] DOE believes this may not be a reasonable alternative for purposes of NEPA because the applicant is unlikely to proceed with the project without fertilizer manufacture as it is essential to its financing of the project. This is another example of a situation in which there is a divergence of alternatives under CEQA and NEPA.

and still operate, or what are its operating characteristics (efficiency, syngas and slag composition, etc.) at 75 percent capacity.

- Energy Commission staff acknowledges that the fertilizer plant is a very useful flywheel to allow some flexibility between electricity and fertilizer production, as the H2 production out of the gasifier is fairly fixed.

- Under the No Fertilizer Manufacturing Complex (Reduced Project) Alternative, the downstream effects should follow. If the gasifier has to operate at 100 percent capacity: coal, ash, sulfur, and electricity should all be tied to that. Should staff determine that the gasifier can operate at 75 percent, downstream numbers could reflect that change, with staff acknowledging any consequences to the gasifier operating off of its design point.

Environmental Analysis

Air Quality

Total HECA project criteria air emissions would change if the fertilizer plant is not built. Nitrogen oxide (NOx) emissions from the fertilizer plant are approximately 11 percent of the total NOx and particulate emissions including inhalable particulate matter less than 10 microns in diameter (PM10). Fine particulate less than 2.5 microns in diameter (PM2.5) are approximately 2 percent of the total PM10 and PM2.5 emissions from stationary source operation of the HECA plant. These emission reduction percentiles are based on the annual permitted HECA stationary source emissions totals (refer to **Air Quality Table 17** within Section 4.1 of this PSA/DEIS) and do not include emissions associated with the OEHI EOR component, nor the expected emissions reductions associated with reduced cooling tower heat rejection. The addition of the fertilizer plant to the HECA project also provides operational flexibility for the gasifier's hydrogen and CO_2 products use, so removing the fertilizer plant could cause an increase in gasifier startup and shutdown frequency that could increase the operating emissions. However, the emissions increase from the loss of operational flexibility is expected to be less than the emissions reduction from removing the fertilizer plant. In addition, emissions from construction and from product transportation during operation would decrease if the fertilizer plant is not built. However, with Energy Commission staff's proposed conditions of certification, air quality impacts from HECA, including impacts from construction and transportation, would be fully mitigated. Therefore, the No Fertilizer Manufacturing Complex (Reduced Project) Alternative would not lessen or avoid any significant (and unmitigable) air quality impact.

Biological Resources

Under the No Fertilizer Manufacturing Complex (Reduced Project) Alternative, the HECA project's habitat impact calculation would not change with the removal of this component from the site plan since staff considers use of the 453-acre project site a complete loss of habitat values. However, with the removal of the fertilizer plant and necessary infrastructure to serve the fertilizer complex manufacturing and distribution, fewer vehicle trips would be necessary during operations which would benefit terrestrial wildlife by reducing the effects of increased traffic volumes on wildlife population dynamics, such as vehicle-related road mortality, disturbance and stress from increased human encroachment, changes in prey availability and predator abundance, and reduced genetic exchange as a result of fewer road crossing attempts by wildlife. Although the number of vehicle trips that would decrease from not constructing the fertilizer complex is unknown, staff believes the number of truck trips directly attributed to the manufacturing and distribution of nitrogen-based products is a small percentage of the total operational traffic. While the number of vehicle trips would not be reduced significantly, fewer vehicle trips on roadways would reduce the potential of direct traffic mortality to terrestrial wildlife, primarily San Joaquin kit fox, blunt-nosed leopard lizard, and other upland species of the southern San Joaquin Valley. Overall, impacts related to biological resources would be slightly less under the No Fertilizer Manufacturing Complex (Reduced Project) Alternative when compared to HECA, primarily due to the reduced number of vehicle trips on roadways.

Carbon Sequestration and Greenhouse Gas Emissions

The carbon sequestration operations of the HECA project would not be directly affected by the removal of the fertilizer plant from the project. The CO_2 emissions from the gasifier would still be separated in the same proportions and sent to OEHI for use in EOR and carbon sequestration. Staff has provided conditions of certification and associated verifications to ensure that the impacts from carbon sequestration are less than significant. Therefore, with staff's proposed mitigation measures, the carbon sequestration impacts would be less than significant for the No Fertilizer Manufacturing Complex (Reduced Project) Alternative.

The greenhouse gas emissions from the HECA project would be reduced by a small degree if the fertilizer plant is not built. The carbon dioxide equivalent (CO_2E) emissions from the fertilizer plant are approximately two percent of the total HECA stationary source CO_2E emissions (refer to **Carbon Sequestration and Greenhouse Gas Emissions Table 4** in Section 4.3 of this PSA/DEIS). In addition, greenhouse gas emissions from construction and from product transportation during operation would decrease if the fertilizer plant is not built. However, the removal of the fertilizer plant would not directly impact the carbon sequestration requirements for the facility or impact the CO_2E emissions from the OEHI CO_2 EOR component. The removal of the fertilizer plant would not change the impact determination of the HECA project's greenhouse gas emissions, which were evaluated in the context of the electricity system as a whole and would be less than significant for the No Fertilizer Manufacturing Complex (Reduced Project) Alternative. Yet to be studied is whether operation of the No Fertilizer Manufacturing Complex Alternative facility's electricity would meet California's Environmental Performance Standard developed in response to SB 1368. This may depend on the facility's ability to operate reliably without swinging gasifier output between electricity production and fertilizer manufacturing.

Cultural Resources

Although the No Fertilizer Manufacturing Complex (Reduced Project) Alternative would involve less ground disturbance compared to HECA, staff believes that the impact conclusions would be essentially identical. Removal of the fertilizer manufacturing complex would reduce the horizontal extent of ground disturbance on the HECA site, but all other project elements would remain the same for the purposes of the cultural resources analysis. Specifically, this alternative would affect the same suite of surface archaeological resources as HECA project components, and the severity of impact would be the same. Because the applicant has not yet provided staff with adequate information to assess the proposed project's impacts on buried archaeological resources and cultural resources in the EOR components of the proposed project (see the **Cultural Resources** section of this PSA/DEIS), staff cannot analyze the impacts of this alternative on such resources. Removal of the fertilizer manufacturing complex would not change the project's impacts on the Old Headquarters Weir or the California Aqueduct: as with the HECA project, these impacts would be less than significant under the No Fertilizer Manufacturing Complex (Reduced Project) Alternative.

Geology and Paleontology

The No Fertilizer Manufacturing Complex (Reduced Project) Alternative would slightly reduce the number and size of the facility's structures. Because staff is not able to make assumptions based upon the scale of this possible reduction, staff assumes the No Fertilizer Manufacturing Complex (Reduced Project) Alternative would be constructed within the same project site footprint, absent the fertilizer complex and necessary infrastructure to serve fertilizer and other nitrogen-based product manufacturing and distributing.

Both HECA and the No Fertilizer Manufacturing Complex (Reduced Project) Alternative are located in an active geologic area of the southern Great Valley geomorphic province in western Kern County, California. Because of its geologic setting, the site could be subject to moderate to high levels of earthquake-related ground shaking. Significant thicknesses of expansive clay soils are also present at the surface.

There are no known viable geologic or mineralogical resources at the site, with the exception of the oil and gas fields of the Naval Petroleum Reserve. Paleontological resources have been documented regionally within Quaternary alluvium and Tertiary Tulare Formation, similar to deposits that underlie the project site. Quaternary alluvium and Pliocene to Pleistocene Tulare Formation deposits beneath the proposed site have a high sensitivity rating for paleontologic impacts. Based on the soils profile, assessment criteria, and the shallow depth of potentially fossiliferous geologic units, staff considers the probability of encountering paleontological resources during construction of HECA to be high. Quaternary alluvium near the surface is less sensitive relative to deeper and older alluvium (refer to **Geology and Paleontology** section of this PSA/DEIS, Section 5.2), however, all Quaternary sediments at the project site should be considered to have a high sensitivity rating until determined otherwise by a qualified professional paleontologist. Since the upper portion of the surface has been disturbed during agricultural operations, the upper 1 to 2 feet of ground would not be likely to yield fossil remains in their natural context. Any excavation into undisturbed native ground at the surface or below disturbed material at the proposed HECA site and along project linears, would be considered to have a high potential to encounter significant paleontological resources.

Mass grading operations within structure footprints of the No Fertilizer Manufacturing Complex (Reduced Project) Alternative, that could be required for removal of expansive clays, would have the potential to disturb paleontological resources. Fossil remains could also be encountered in deep trenches excavated for utilities.

As this alternative proposes a slight reduction in the HECA project, all conditions of certification applicable to the project that would mitigate impacts to paleontological resources would be applicable to the No Fertilizer Manufacturing Complex (Reduced Project) Alternative.

The No Fertilizer Manufacturing Complex (Reduced Project) Alternative would not increase impacts to geological or paleontological resources or be subject to geological hazards above the HECA project level. Therefore, no impacts would occur from the No Fertilizer Manufacturing Complex (Reduced Project) Alternative with the incorporation of Conditions of Certification identical to that presented within the **Geology And Paleontology** section of this PSA/DEIS.

Hazardous Materials Management

The No Fertilizer Manufacturing Complex (Reduced Project) Alternative would most likely eliminate the need for many “up-stream” intermediate hazardous and flammable materials that would be produced, used, and stored on the site that are associated with the fertilizer manufacturing complex. To more accurately assess the impacts of a No Fertilizer Manufacturing Complex (Reduced Project) Alternative, staff has made the following assumptions:

- No fertilizer plant, no urea unit, urea pastillation unit, and no urea pastille handling and transfer unit.
- No anhydrous ammonia production or storage of up to 3.8 million gallons of anhydrous ammonia would occur on-site. Instead, aqueous ammonia would be imported onto the site in tanker trucks for use in Selective Catalytic Reduction (SCR).
- The Air Separation Unit (ASU) would no longer be used to produce nitrogen for fertilizer production but would continue to be used to provide oxygen for the gasifier.
- There would be no need for the production and storage of nitric acid, an intermediate substance produced and then used in the UAN production process (UAN is a solution of urea and ammonium nitrate in water used as a fertilizer), and thus on-site storage of extremely large volumes (5,200,000 pounds) of highly concentrated acid (~60 percent by weight) for up to three days on-site would be eliminated.

Given the above assumptions, the need for hazardous materials management on the site and impacts to the off-site public during both construction and operations would be reduced under this alternative, but only by a small amount. The removal of large amounts of stored anhydrous ammonia, nitric acid, and UAN liquid would reduce the need to properly manage these hazardous materials and would reduce slightly the potential impacts to the off-site public. The remaining project components under this alternative would include:

- Coal/pet coke gasification plant;
- ASU;
- Syngas scrubber, sour shift, low-temperature gas cooling, sour water treatment facility;
- Mercury removal unit;
- Acid gas removal (Rectisol process) unit;
- A sulfur recovery unit that includes the storage of up to 1.4 million pounds (700 tons) of liquid sulfur at elevated temperatures;
- 13-mile natural gas pipeline;
- 3-mile pressurized CO_2 pipeline;
- EOR Facility; and
- Storage of large volumes of other hazardous materials including sodium hydroxide (60,000 gallons of 5-50 percent concentration), sodium hypochlorite (7,000 gallons of unknown concentration), diesel fuel (2000 gallons), gasoline during construction (4000 gallons), 220,000 pounds of methyldiethanolamine (40 percent), and 300,000 gallons of methanol.

These remaining components would continue to constitute a highly complex industrial environment necessitating increased vigilance and risk management. Furthermore, the need to import aqueous ammonia for selective catalytic reduction (SCR) would result in new potential risks to the off-site public during transportation, transfer operations from tanker truck to an on-site storage tank, and storage.

Staff has repeatedly found at numerous other power plants that the greatest risk of an accidental release occurs during the transfer of liquid hazardous materials to/from a tanker truck. Since no anhydrous ammonia would be transported to or from the facility under the original project and no transfer between an on-site storage tank and a tanker truck would occur, the need to import aqueous ammonia under the No Fertilizer Manufacturing Complex (Reduced Project) Alternative would add an increased risk to the off-site public. Therefore, the decrease in hazards due to the elimination of anhydrous ammonia and other large-volume hazardous materials would be off-set by the addition of a new risk of aqueous ammonia transport and transfer, thus resulting in a net minimal reduction in overall risk posed to the off-site public. Staff concludes that there would be a slight reduction in impacts on hazardous materials management with the No Fertilizer Manufacturing Complex (Reduced Project) Alternative. Staff therefore would continue to recommend that all proposed conditions of certification in the **Hazardous Materials Management** section of the PSA/DEIS be retained to mitigate the impacts.

Staff bases its proposed mitigation for the No Fertilizer Manufacturing Complex (Reduced Project) Alternative on two factors:

- The complexity of the proposed HECA facility even when modified; and
- The use and storage of vast amounts of flammable and combustible materials even when modified.

The presence of numerous chemical processes - specifically the larger gasification process and sulfur recovery process that consists of large amounts of hazardous materials in closed tanks and piping at elevated temperature and pressure - could potentially pose significant risks if not managed properly. Staff determined that all of the proposed processes, even under the No Fertilizer Manufacturing Complex (Reduced Project) Alternative, must be managed and monitored in greater detail than usual, regardless if the quantities of hazardous materials present are below the federal or state thresholds that would trigger this increased level of safety management. Staff continues to propose that the project owner be required to develop a Process Safety Management Plan (PSM Plan) which includes a Hazard and Operability analysis to address several different processes, a Risk Management Plan (RMP) which would include several new Offsite Consequence Analyses, and a Spill Prevention Control and Countermeasures (SPCC) Plan for each of the approximately ten processes that would remain as part of the project under the No Fertilizer Manufacturing Complex (Reduced Project) Alternative.

Staff believes that these plans will identify potential system failures before failure can occur and indicate/implement mitigation to reduce the risk of on-site and off-site consequences to less than significant. Establishing and implementing a strict code of process safety management and implementing engineering and administrative controls to prevent accidents, followed by quick and effective spill containment, control, and cleanup should an accidental release occur, would reduce both the chance and severity of an impact to an insignificant level.

In conclusion, staff finds that the No Fertilizer Manufacturing Complex (Reduced Project) Alternative would result in only a slight reduction of the impacts on hazardous materials management but that no difference in proposed mitigation is warranted.

Land Use and Agriculture

The initial Amended HECA AFC (2012) submitted by the project applicant included a chemical manufacturing complex proposed to produce products for agricultural, transportation and industrial uses. Kern County provided response letters in June and July of 2012 stating that such a manufacturing complex would constitute an industrial land use and would require a zone change and a General Plan Amendment to a compatible land use designation (Kern County 2012d, Kern County 2012e). To address this issue, the project applicant revised the HECA project to restrict production of "nitrogen-based products" (including urea, urea ammonium nitrate and anhydrous ammonia) to manufactured products for the purpose of "fertilizer manufacture and storage for agricultural use only" (HECA 2012jj). It should be noted that LORS conformance is a CEQA issue, as discussed within the **Land Use** section of this PSA/DEIS.

The March 6, 2013 Kern County Planning Department letter stated the revised HECA project description to restrict the chemical manufacturing and storage of fertilizers for agricultural use only, would comply with the County General Plan and Zoning Ordinance (Kern County 2013a). Kern County staff recommends that if approved by the Energy Commission, the project “include Mitigation Measure(s) to restrict the items produced on site and in the Manufacturing Complex to ’fertilizer manufacture and storage for agricultural use only’ per Section 19.12.030.A of the Kern County Zoning Ordinance.” Staff is recommending Condition of Certification **LAND-6**, which would require the project applicant to restrict the products from the chemical manufacturing complex to fertilizer for agricultural use only.

The No Fertilizer Alternative would remove this issue from the land use and agriculture analysis and eliminate proposed Condition of Certification **LAND-6.** Therefore land use impacts would be less under the No Fertilizer Manufacturing Complex (Reduced Project) Alternative than that of HECA.

Noise and Vibration

There would be less noise and vibration impacts under this alternative due to the elimination of one of the sources of noise, the manufacturing complex, and product truck transport to market.

Public Health and Safety

The No Fertilizer Manufacturing Complex (Reduced Project) Alternative would most likely eliminate the need for other processes associated with the manufacture of fertilizer. The same assumptions as made by staff above under Hazardous Materials Management are utilized to more accurately assess the impacts of the No Fertilizer Manufacturing Complex (Reduced Project) Alternative. Given these assumptions, the number of sources of emissions that could potentially impact public health would be slightly reduced.

Staff analysis shows the public health and safety impacts of HECA would be below the level of significance during the construction phase when diesel particulate matter (DPM) emissions from construction equipment and vehicles would be emitted. A somewhat shorter construction period would result in slightly lower emissions of DPM from ground moving equipment and other construction equipment. This difference would be negligible.

For the operations phase of HECA, the project applicant and staff modeled 294 emitting units and 54 toxic air contaminants that would be emitted from stacks, flares, or as fugitive emissions from valves, flanges, and other sources. Eliminating the above-mentioned sources under a No Fertilizer Manufacturing Complex (Reduced Project) Alternative would bring these values down to approximately 250 emitting units and 48 toxic air contaminants. Staff's analysis in the **Public Health** section of this PSA/DEIS (refer to Section 4.8) found that toxic air contaminants from the following sources contributed the most to the risk posed to public health: Heat Recovery Steam Generator (HRSG), coal dryer, CO_2 vent, gasification fugitives, shift area fugitives, Acid Gas Recovery (AGR) fugitives, Sulfur Recovery Unit (SRU) fugitives, and (Sour Water Strippers (SWS) fugitives. Not one of the units staff assumed would not exist under the No Fertilizer Manufacturing Complex Alternative was found to contribute significantly to the risk posed to public health. Therefore, staff concludes that the reduction in emissions under the No Fertilizer Manufacturing Complex (Reduced Project) Alternative would not result in any significant reduction in risk.

Under this alternative, the remaining project components would include:

- Coal/pet coke gasification plant;
- ASU;
- Syngas scrubber, sour shift, low-temperature gas cooling, sour water treatment facility;
- Mercury removal unit;
- Acid gas removal (Rectisol process) unit;
- Sulfur recovery unit that includes the storage of up to 1.4 million pounds (700 tons) of liquid sulfur at elevated temperatures;
- 13-mile natural gas pipeline;
- 3-mile pressurized CO_2 pipeline;
- EOR facility; and
- Storage of large volumes of other hazardous materials including sodium hydroxide (60,000 gallons of 5-50 percent concentration), sodium hypochlorite (7,000 gallons of unknown concentration), diesel fuel (2000 gallons), gasoline during construction (4000 gallons), 220,000 pounds of methyldiethanolamine (40 percent), and 300,000 gallons of methanol plus vehicular emissions.

Staff has determined these components would pose an insignificant risk to public health as estimated by staff. However, staff continues to propose mitigation for the No Fertilizer Manufacturing Complex (Reduced Project) Alternative. To ensure that long-term routine operating emissions would not, as estimated, pose a significant risk to the off-site public, staff proposes that routine sampling of certain toxic air contaminants that pose the greatest potential risk and hazard to the public be required and that a health risk assessment be conducted, as per the requirements and schedule of Conditions of Certification **PUBLIC HEALTH-1, PUBLIC HEALTH-2, and PUBLIC HEALTH-3**, as found in the **Public Health** section of this PSA/DEIS (refer to Section 4.8).

In conclusion, staff finds that the estimated risks posed to public health from the No Fertilizer Manufacturing Complex (Reduced Project) Alternative would be similar to HECA.

Socioeconomics

Because HECA would not result in significant impacts to socioeconomic resources, no significant socioeconomic impacts would likely occur under the No Fertilizer Manufacturing Complex (Reduced Project) Alternative. The reduction in the project scope would decrease the construction and operations workforce necessary for HECA project implementation, therefore, lessening the total potential impact on socioeconomic resources. The reduction in the HECA project scope would also likely reduce the value of the economic benefits (namely jobs and construction spending) that would accrue to communities in the project area.

Soil and Surface Water

Staff estimates that removing the fertilizer manufacturing facility from the HECA project would reduce the total impervious area by roughly 35 percent. Due to this reduction, the impacts of this alternative for potential erosion during construction would be less than HECA. Although this alternative would decrease the amount of impervious area and eliminate the potential for contamination of nitrogen-based manufacturing, impacts to water quality would only be somewhat less than HECA because the use of retention basins would reduce these impacts to offsite water resources. Because all other aspects of the project would remain the same, the other impacts of this alternative relating to soil and surface water would be similar to the HECA project.

Traffic and Transportation

Elimination of the fertilizer manufacturing facility from HECA would reduce the number of truck trips generated during operations. The number of truck trips that would be generated by the fertilizer manufacturing facility account for approximately one-third of the total truck trips generated during construction and operation activities. Potential impacts associated with increased traffic and potential aircraft hazards (i.e., exhaust plumes) would remain with implementation of this alternative. Overall, impacts related to traffic and transportation would be less under the No Fertilizer Manufacturing Complex (Reduced Project) Alternative.

Transmission Line Safety and Nuisance

Without the fertilizer manufacturing facility, the additional transmission line for importing power (from the PG&E power grid) for the identified on-site Air Separation Unit would be the same as the proposed project, because the air separation unit would still be needed to provide oxygen for the main gasifier.

Visual Resources

The No Fertilizer Manufacturing Complex (Reduced Project) Alternative would remove the structures associated with the manufacturing of low-carbon, nitrogen-based products. As such, some of the manufacturing complex’s more prominent structures (i.e. the urea and UAN storage units) would be removed from the view at KOP 1. However, the feedstock barn, the largest and most prominent structure from the view at KOP 1, would remain unaffected by this alternative. Therefore, the visual impact associated with the No Fertilizer Manufacturing Complex (Reduced Project) Alternative would be identical to HECA’s significant visual impact.

Waste Management

HECA would produce thousands of tons per year of waste during the operation of the facility due to the operation of the gasification process. The majority of the waste from HECA would be gasification solids. The fertilizer plant does not produce gasification solids. Waste management impacts from the No Fertilizer Manufacturing Complex (Reduced Project) Alternative would be similar to HECA with respect to volume of waste disposal. Potential impacts to human health and the environment would be slightly less since the area of soil disturbance in potentially contaminated areas would be less.

Water Supply

Staff cannot determine what change there may be in the impacts to water supply when considering the No Fertilizer Manufacturing Complex (Reduced Project) Alternative. Figure 2-10 of the Amended AFC shows that production of 'Low-Carbon Nitrogen Products' would require the use of 5% of the total project water use. This would constitute approximately 375 acre feet per year of the maximum total water use of 7,500 AFY. If the reduction in water use for the No Fertilizer Manufacturing Complex (Reduced Project) Alternative is proportionate to the HECA project water use then the level of impacts would be somewhat less than HECA. If the reduction in water use is not proportionate and the No Fertilizer Manufacturing Complex (Reduced Project) Alternative results in increased power production due to more availability of hydrogen gas for combustion, then water use for cooling could increase and impacts could be somewhat to significantly increased. Staff needs more information on how the gasifier and combined cycle could or would be operated to evaluate the relative impact from the No Fertilizer Manufacturing Complex (Reduced Project) Alternative.

Worker Safety and Fire Protection

Although worker safety is evaluated on the basis of LORS conformity and not CEQA, staff has provided an analysis of changes in potential worker safety impacts for this alternative. The No Fertilizer Manufacturing Complex **(**Reduced Project) Alternative would most likely eliminate the need for many "up-stream" intermediate hazardous and flammable materials to be produced, used, and stored on the site. Assumptions made by staff above in Hazardous Materials Management are used to more accurately assess the impacts of the No Fertilizer Manufacturing Complex Alternative. Given these assumptions, the on-site impacts to workers during construction and operations would be reduced under this alternative but not by a significant amount.

The removal of large amounts of stored anhydrous ammonia, nitric acid, and UAN liquid would reduce hazards to workers somewhat but the remaining project components would include:

- Coal/pet coke gasification plant;
- ASU;
- Syngas scrubber, sour shift, low-temperature gas cooling, sour water treatment facility;
- Mercury removal unit;
- Acid gas removal (Rectisol process) unit;
- Sulfur recovery unit that includes the storage of up to 1.4 million pounds (700 tons) of liquid sulfur at elevated temperatures;
- 13-mile natural gas pipeline;
- 3-mile pressurized CO_2 pipeline;
- EOR facility; and
- Storage of large volumes of other hazardous materials including sodium hydroxide (60,000 gallons of 5-50 percent concentration), sodium hypochlorite (7,000 gallons of unknown concentration), diesel fuel (2000 gallons), gasoline during construction

(4000 gallons), 220,000 pounds of methyldiethanolamine (40 percent), and 300,000 gallons of methanol plus vehicular emissions.

Staff has determined that all of these components would continue to constitute a dangerous work environment necessitating increased vigilance to protect worker safety. Furthermore, the need to import aqueous ammonia for SCR would result in a new risk to workers during transfer operations from a tanker truck to an on-site storage tank. Therefore, the net results in hazards posed to workers would be minimal and staff concludes that there would be no significant reduction in impacts on worker safety with the No Fertilizer Manufacturing Complex (Reduced Project) Alternative.

Regarding impacts on fire protection, there would continue to be a serious need for fire detection, suppression, and off-site response under this alternative. Although HECA would be somewhat reduced under this alternative, the remaining project components would continue to require on-site fire protection measures and off-site response by the Kern County Fire Department (KCFD). Therefore, staff also concludes that there would remain a significant direct and cumulative impact on the Kern County Fire Department. As stated in staff's **Worker Safety and Fire Protection** section of this PSA/DEIS (refer to Section 4.16), the KCFD identified the need for nine specific mitigation measures:

1. Provide a fire-fighting foam pumper/tender to fight methanol fires.
2. Provide a fire protection specialist to be hired by the KCFD during the plan review process.
3. Purchase a plot of land for the relocation of KCFD station 53 and a helipad.
4. Provide 50 percent of the costs of a KCFD fire prevention inspector during the construction phase.
5. Provide the costs of training the crews at five fire stations who would respond to emergencies at the facility.
6. Purchase to the KCFD a fire rescue truck with a rotator crane to assist in vehicular accidents within Kern County.
7. Provide air monitoring equipment to the KCFD that will monitor multiple toxic gases.
8. Provide funds for six fire engineer positions needed to operate the foam pumper/tender.
9. Contribute annual funds to help maintain the reverse 9-1-1 system.

Staff independently arrived at the same opinion for some of the requested mitigation and has proposed Condition of Certification **WORKER SAFETY-8** to address the direct incremental and cumulative impacts on the KCFD and to ensure that emergency response for fires, spills, rescue, and EMS are adequate. The mitigation staff proposes for the full project is also proposed for the No Fertilizer Manufacturing Complex (Reduced Project) Alternative because the need for mitigation would remain.

Staff bases its proposed mitigation for the No Fertilizer Manufacturing Complex (Reduced Project) Alternative on several factors. First, the complexity of the HECA project facility, the use and storage of vast amounts of flammable and combustible materials, the relatively remote location, and the size of the industrial environment, even for a reduced project, all dictate the need for the following efforts to be undertaken by the KCFD:

1. Complex plan reviews.
2. Frequent hazmat and fire inspections.
3. Emergency Response including medical, fire, rescue, and hazardous materials incidents.

Second, as stated in the **Worker Safety and Fire Protection** section of this PSA/DEIS, standard fire department responses for a fire and for a hazmat spill include response from two fire stations and at least three fire fighters from each station regardless of the number and amounts of hazardous materials stored on the site. No matter what size the fire or how many workers are initially in need of rescue, the KCFD would dispatch engines from at least two fire stations so that at a minimum, six firefighters are sent to the scene. Also, the issue of “draw-down” remains a concern even under the No Fertilizer Manufacturing Complex (Reduced Project) Alternative if two or more fire stations are dispatched to the HECA site. The community cannot be left without fire response and thus crews from other KCFD stations would be dispatched to cover the areas vacated by those going to aid at the HECA facility. Because of the very serious threat of escalation from a small incidence to a much larger incidence at the HECA facility even if it is reduced in size and number of industrial processes, dispatch from more stations will be the rule rather than the exception and draw-down would occur more rapidly.

Third, it is very important to note that the HECA facility would be located in an area that has a rather harsh environment in the summer months and the ability of a fire fighter to perform duties while wearing a turn-out coat, heavy boots, and a respirator (self-contained breathing apparatus) is limited under the best of circumstances. Severe limits on a fire fighter’s ability to perform duties necessitate the mobilization of more fire fighters to respond to an emergency and hence potential for greater draw-down impact.

In conclusion, staff finds that on the whole, the No Fertilizer Manufacturing Complex (Reduced Project) Alternative would not substantially reduce the impacts on fire protection or on the impacts to the KCFD.

CEQA ENVIRONMENTALLY SUPERIOR ALTERNATIVE

A CEQA environmentally superior alternative (Cal. Code Regs., tit. 14, §15126.6[e][2]) will be identified in the FSA/FEIS.

NEPA ENVIRONMENTALLY PREFERRED ALTERNATIVE

A NEPA environmentally preferred alternative (CEQ §1505.2[b]) will be identified in the FSA/FEIS.

REFERENCES

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California Division of Land Resources Protection 2013 – Important Farmland Data [online]: http://redirect.conservation.ca.gov/dlrp/fmmp/product_page.asp. Accessed April.

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HECA 2012x – SCS Energy California, LLC/URS/D. Shileikis (tn 67515). Response to Sierra Club's Data Requests Nos. 1 - 97, dated 10/03/2012. Submitted to CEC Docket Unit on 10/03/2012.

HECA 2012jj - Latham & Watkins LLP/M. Carroll (tn 68600). Objections and request 45-day extensions to Set 3 Data Requests A181(a), A183 (a)-(c), A184, A185, A192, A193, A194, A196, A197(a)-(e), A198, A199, A200(1)-(5), A201, A202, A203, A204, A205(a)-(c), A206(a)-(d), A207, A208, A209, A210, A211, and A212., dated 11/20/2012. Submitted to CEC Docket Unit on 11/20/2012.

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HEI 2008a - Hydrogen Energy International, LLC /J. Briggs (tn 47347). Application for Certification, dated 07/30/08. Submitted to CEC/Docket Unit on 07/31/08

HEI 2009c - Hydrogen Energy International, LLC /J. Briggs (tn 51735). Revised Application for Certification, dated 05/28/09. Submitted to CEC/Docket Unit on 05/28/09.

Kern County 2012d – Kern County Planning and Community Development Department (tn 65837). Letter to Applicant: Request for Land Use Amendments, dated 06/11/2012. Submitted to Docket Unit on 06/19/2012.

Kern County 2012e – Kern County Planning and Community Development Department (tn 65840). Letter to CEC: Response to Request for Agency Participation, dated 06/11/2012. Submitted to Docket Unit on 06/19/2012.

Kern County 2013a – Kern County Planning and Community Development Department Comments on the HECA Project (TN 69831). March 6, 2013

Kern County 2013b – Kern County Engineering, Surveying, and Permit Services – Zone Maps [online]: http://esps.kerndsa.com/maps/zone-maps. Accessed April.

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ALTERNATIVES Appendix 1
Staff Contributors to the HECA Project Alternatives Analysis

All National Environmental Policy Act (NEPA)-related text and analysis provided by the U.S. Department of Energy (DOE) staff.

Energy Commission staff contribution to the California Environmental Quality Act (CEQA)-related text and analysis include the following:

Issue Area	Energy Commission Staff Contributor
Air Quality	William Walters, Nancy Fletcher
Biological Resources	Amy Golden, Carol Watson
Cultural Resources	Gabriel Rourke, Melissa Maroukas
Geology and Paleontological Resources	Casey Weaver
Growth Inducing Impacts	Lisa Worrall
Greenhouse Gases and Carbon Sequestration	William Walters, Gerry Bemis, Dave Vidaver
Hazardous Materials	Alvin Greenberg
Land Use and Agriculture	Jonathan Fong
Noise and Vibration	Shahab Khoshmashrab
Public Health	Alvin Greenberg, Huei-An Chu, Gerry Bemis
Socioeconomics	Aaron Nousaine, Lisa Worrall
Soil and Surface Water	Mike Conway, Marylou Taylor
Transportation & Traffic	John Hope
Transmission Line Safety and Nuisance	Obed Odoemelam, Huei-An Chu
Visual Resources	Elliott Lum
Waste Management	Ellie Townsend-Hough
Water Supply	Mike Conway, Paul Marshall
Worker Safety & Fire Protection	Alvin Greenberg
Engineering Staff and Alternatives Still Under Consideration	Gerry Bemis, Matthew Layton

U.S. DEPARTMENT OF ENERGY

Environmental Consequences

1.1 U. S. DEPARTMENT OF ENERGY - ENVIRONMENTAL CONSEQUENCES

1.1.1 Air Quality

The Project would generate emissions of criteria pollutants including nitrogen oxide (NO_X), carbon monoxide (CO), volatile organic compounds (VOCs), sulfur dioxide (SO_2), and particulates less than or equal to 10 microns in diameter and 2.5 microns in diameter (PM_{10} and $PM_{2.5}$) during construction and operations.

In the construction phase, emissions would be reduced through the implementation of fugitive dust mitigation and diesel equipment exhaust mitigation. Construction emissions will be further mitigated through participation in the San Joaquin Valley Air Pollution Control District's Emission Reduction Incentive Program, pursuant to which the Hydrogen Energy California (HECA) Project will pay fees to the District to be invested in emission reduction projects in the vicinity of the HECA Project.

During operations, emissions will be mitigated through the installation of best available emission control technology. Remaining emissions of NO_X, VOC, SO_2, and PM_{10} would be fully offset by providing emission reductions from emission reduction credits. Transportation emissions associated with trucks and/or trains will be mitigated through participation in the District's Emission Reduction Incentive Program described above. The air dispersion modeling analyses conducted for NO_X, CO, SO_2, PM10 and PM2.5 results show that the HECA Project, with the planned emission control systems and other forms of mitigation, would neither cause an exceedance of the California and National Ambient Air Quality Standards nor contribute significantly to an existing exceedance.

By complying with all applicable laws, ordinances, regulations, and standards (LORS), as well as implementing Project design features and Conditions of Certification, the Project would not result in significant impacts to air quality.

1.1.2 Biological Resources

No threatened or endangered plant or wildlife species were identified on the HECA Project Site. However, threatened or endangered plant or wildlife species could be impacted by construction of the HECA Project linears or the Occidental of Elk Hills, Inc. Project. To ensure that no threatened or endangered plant or animal species are affected by the Project, avoidance and Conditions of Certification—such as pre-construction surveys and exclusionary fencing—would be implemented to reduce impacts on threatened and endangered species.

The Project construction and operation would avoid nearly all of the potential jurisdictional waters in the delineation study area. Portions of the CO_2 pipeline will be constructed using horizontal directional drilling (HDD) to avoid environmentally sensitive areas associated with the California Aqueduct and Kern River Flood Control Channel. Wetland features adjacent to the proposed natural gas linear right-of-way would be avoided.

Only a total of 0.20 acre of potential jurisdictional nonwetland waters of the United States would be temporarily impacted during construction associated with the natural gas pipeline. No wetlands would be impacted, and no permanent impacts to any jurisdictional features are expected, pending final jurisdictional determination.

1.1.3 Climate

A key objective of HECA is to mitigate impacts related to climate change by reducing greenhouse gas emissions relative to those emitted from conventional coal-fuel–fired power generation and nitrogen-based fertilizer manufacturing by capturing and sequestering CO_2 emissions. HECA would emit less than 400 lb CO_2 per megawatt hour by capturing approximately 90 percent of the carbon in the synthesis gas, and beneficially using it for Enhanced Oil Recovery at a nearby oil field. (Energy Commission staff's CEQA analyses indicate that HECA would emit 1,000 to 1,120 lb CO_2 per MWh during early operations and 788 to 843 lb CO_2 per MWh if and when it reaches mature operations, expected after about two years of early operations.) The development of the clean coal technology and demonstration of carbon capture and sequestration at this scale will pave the way for future low-carbon projects. Therefore, HECA provides a benefit toward minimizing climate change. If HECA is constructed and attains mature operations, it would demonstrate that coal facilities could be carbon-equivalent to natural gas facilities.

1.1.4 Cultural Resources

Cultural resources have been identified in the Project area. The Applicant proposes to avoid these resources to ensure that no significant impacts would occur. However, the applicant has not yet demonstrated the ability to avoid damaging known cultural resources. In addition, the historical significance of most identified cultural resources in the Project area has not been determined. As such, staff is unable to draw definite conclusions regarding the significance of the proposed project's impacts on cultural resources. Similarly, staff is currently unable to determine whether the proposed project would comply with all applicable LORS. These information gaps prevent staff from determining whether the proposed project would result in significant impacts on cultural resources.

1.1.5 Geologic Hazards and Resources

There are no known active or potentially active faults in the immediate Project area. The primary geologic hazards include ground motion from a seismic event centered on nearby active faults, and the potential for expansive soils due to high clay content in surface soils.

Project facilities would be designed in accordance with applicable building code seismic design criteria. To reduce the potential for adverse differential settlement, removal of the susceptible soils and replacement with engineered fill has been recommended where appropriate.

By complying with all applicable LORS as well as implementing Project design features and Conditions of Certification, the Project would not be adversely impacted by geologic hazards and would not result in significant impacts on geologic resources.

1.1.6 Hazardous Materials Handling

Of the chemicals proposed for use at the HECA Project Site, only anhydrous ammonia would be stored in quantities above the federal threshold found in 40CFR 68.130 (10,000 lbs).,And, only anhydrous ammonia would be stored on the site in a quantity greater than the California Accidental Release Prevention Program threshold (10,000 lbs). Based on the results of the Offsite Consequence Analysis, no offsite impact is expected to occur.

By complying with all applicable LORS as well as implementing Project design features and Conditions of Certification, the Project would not result in significant impacts from hazardous materials handling.

1.1.7 Land Use

The majority of the HECA Project Site is currently used for agricultural purposes, and is designated Prime Farmland. The Project Site is also under Williamson Act contract. Williamson Act restrictions on the HECA Project Site would need to be cancelled pursuant to California Government Code Section 51280(b)..While the project would meet zoning requirements with a conditional use permit, it is unclear whether or not the project is fundamentally compatible with existing land uses and if the conditional use permit findings of approval can be met. Staff cannot reach a conclusion on the potential significant issues on land use until the outstanding information identified in the technical areas requesting such information is provided.

1.1.8 Noise

Noise impacts on sensitive receptors were evaluated for construction, commissioning, operations, groundborne vibrations, and vehicle traffic. In addition, worker exposure noise impacts were evaluated. Construction noise is usually considered a temporary phenomenon, but the construction period for HECA would extend beyond what is reasonably considered “a temporary phenomenon” (approximately 3.5 years). Construction-related traffic noise may cause significant impacts at noise-sensitive receptors within the proximity of the project’s truck route, and therefore, mitigation measures may be required near those receptors to reduce the noise impacts to less than significant. This would be accomplished by Condition of Certification **NOISE-9**, which would require an evaluation of the impacts, and if found necessary, implementation of appropriate mitigation measures. The Project has also incorporated extensive noise-reduction features to minimize noise levels during operation.

1.1.9 Paleontological Resources

Project construction could impact paleontological resources within the Quaternary alluvium and the Plio-Pleistocene Tulare Formation. Therefore, Conditions of Certification would be implemented to reduce potential adverse impacts on paleontological resources resulting from Project construction. The paleontological resources impact mitigation program would ensure that direct, indirect, and cumulative adverse environmental impacts on paleontological resources would not be significant. Conditions of Certification would allow for the salvage of fossil remains and associated specimen data and corresponding geologic and geographic site data that otherwise might be lost to earth-moving and to unauthorized fossil collecting.

By complying with all applicable LORS as well as implementing Project design features and Conditions of Certification, the Project would not result in significant impacts on paleontological resources.

1.1.10 Public Health

During construction, toxic air contaminant (TAC) emissions would be reduced through the implementation of diesel equipment exhaust mitigation. During operations, the emissions control systems of the Project would minimize potential TAC emissions. The maximum incremental cancer risk from Project emissions during construction and operations is estimated to be below the significance criterion of 10 in one million. The maximum chronic and acute total hazard indices are both estimated to be less than the significance criterion of 1.0. Project emissions are expected to pose no significant cancer or noncancer health effects; therefore, emissions from the Project do not pose a significant adverse public health risk. However, Energy Commission staff notes that the integration of coal/petcoke gasification with the production of fertilizer, sulfur, electricity and carbon dioxide results in a complex project and that careful monitoring is needed to ensure that public health and worker safety are not adversely affected by the project.

1.1.11 Socioeconomics and Environmental Justice

The construction and operation of the Hydrogen Energy California (HECA) Project, described in the Amended Application for Certification (AFC), would not result in significant direct, indirect, or cumulative adverse socioeconomic impacts on project area housing, schools, law enforcement services, and parks. The project would not induce substantial population growth, displacement of population, or demand for housing and public services. The Project would have a positive impact on fiscal resources and provide job opportunities in the local community and region. Environmental justice communities were identified near the Project based on a review of U.S. Census data, including low-income and minority communities. Therefore, the Project was evaluated to determine whether these communities might experience disproportionately high and adverse effects as a result of the Project.

Based on the environmental analyses presented in the Preliminary Staff Assessment/ Draft Environmental Impact Statement, several technical areas have identified potential significant unmitigated impacts from the construction and operation of the proposed HECA project, but have not concluded if their significant impacts would remain unmitigated. Therefore, based on the information available to staff, these impacts could have adverse or disproportionate impacts on an environmental justice population.

HECA may result in an increased use of the Wasco coal transloading facility which could result in impacts related to air quality, public health, and traffic and transportation, among others. The potential need for expansion and improvements of the coal transloading facility near Wasco was not analyzed in the PSA/DEIS. Staff will be analyzing these potential impacts in the FSA/FEIS. **Socioeconomic Table 2** shows that on April 1, 2010 there was an 86 percent minority population in Wasco. Staff will assess whether there is an environmental justice population in the immediate vicinity of the transloading facility that could be adversely or disproportionately impacted. Staff will provide updated information in the FSA/FEIS.

1.1.12 Soils

The surficial soils of the HECA Project Site would likely be excavated and recompacted or replaced with granular soils from adjacent onsite areas. Soil removed through grading activities is expected to be reused on the HECA Project Site. During construction and installation of the linear facilities, the soil within the alignment for the linear facilities may become more susceptible to erosion and could result in sediment-laden runoff. The extent of this construction-related impact on water quality and agricultural lands, however, would be temporary and minimized through implementation of appropriate best management practices (BMPs), including erosion control measures.

By complying with all applicable LORS as well as implementing Project design features and Conditions of Certification, the Project would not result in significant impacts on native soil, receiving water bodies, or agricultural lands at or near Project facilities.

1.1.13 Traffic and Transportation

Construction of the Project would result in a temporary increase in traffic associated with the movement of construction vehicles, equipment, and personnel on the transportation network serving the Project area. Where warranted, the Project would use proper signs and traffic control measures in accordance with California Department of Transportation (Caltrans) and Kern County requirements during the construction period. The Project would also coordinate construction activities, including the transport of oversized and overweight loads on state and county roadways, with appropriate Caltrans, California Highway Patrol, and Kern County departments, and with other jurisdictions to maintain traffic flow and safety. In addition, recommended Conditions of Certification by Energy Commission staff would require improvements at six roadway intersections along with redesigning and/or repaving roadway segments identified as needed prior to construction activities to adequately serve the increased heavy truck traffic.

During Project operations, the Project's surrounding area would experience a substantial increase in the frequency of heavy truck operations on local roadways associated primarily with feedstock deliveries. Although Conditions of Certification beyond typical actions is being recommended, the project site is located in an area not adequately served by existing roadways. Specifically, the current roadway system is not designed to support the high number of truck trips that would occur during construction and particularly during operation with implementation of the no rail spur option (Alternative 2). . As a result, recommended Conditions of Certification would require ongoing roadway restoration during operations.

1.1.14 Visual Resources

In general, the HECA Project area is composed primarily of agricultural lands with farming activities and scattered residences. However, it is also characterized by oilfield extraction, grain storage, fertilizer production activities/industrial facilities, and electrical transmission lines. Although the HECA Project would be clearly visible from the west, north, and east, with sporadic visibility from areas located to the south and southeast (within the identified 5-mile radius), the overall landscape is already highly modified by human activity and is considered of low scenic quality.

1.1.15 Waste Management

Wastes generated by the Project during construction and operation include nonhazardous and hazardous wastes. Nonhazardous wastes include scrap metal, paper, sanitary waste, some types of spent catalysts, and storm water. Hazardous wastes that would be generated include paint, solvents, cleaners, sludges, oil, batteries, and hazardous spent catalysts. During operation the project would also generate approximately 306,000 tons (271,584 cubic yards) of gasification solids per year.

An undefined percentage of gasification solids generated from HECA are expected to be used for beneficial reuse, and not disposed in a landfill. The applicant has not provided sufficient data to show a significant quantity would be reused. Based on the remaining capacity and estimated closure dates of the Class I, II, and III landfills in California the project has the potential to consume as much as ten percent of Kern County's Class III landfill capacity, which would be a significant impact. The gasification waste could be excluded from hazardous waste regulations (i.e., 40 CFR Section 261.4 (b) (7) (ii) (F) and Title 22 CCR Section 66261.4(b) (5) (A). However, prior to acceptance of the gasification solids into a Kern County owned and operated landfill the solids must be analyzed and classified as non-hazardous or hazardous waste according to California hazardous waste testing standards. If the solids are determined to be hazardous, the amount of hazardous waste would be burdensome to the State of California and disposal would be costly to the applicant.

Wastewater generated during construction of the Project would include sanitary wastes, equipment wash water, hydrostatic test water, and storm water runoff. Nonhazardous hydrostatic test water would be tested and then disposed. During operation, sanitary wastewater would be disposed in an onsite sanitary leach field. There would be no direct surface water discharge of industrial wastewater or storm water from process areas. Process wastewater would be treated on the HECA Project Site in a zero liquid discharge unit, and recycled within the gasification and Project systems.

1.1.16 Water Resources

HECA would use local groundwater and treat it on site to meet Project standards. Groundwater would be supplied from Buena Vista Water Storage District (BVWSD), as part of BVWSD's Brackish Groundwater Remediation Project, which is designed to remediate brackish groundwater that is considered to be unsuitable for agricultural or drinking uses. Potable water would be supplied by the West Kern Water District. Potable water would be used for drinking and sanitary purposes only. Energy Commission staff's analysis shows that it is likely the proposed supply would have beneficial uses for agriculture and may be usable as a drinking water supply. Energy Commission staff has also concluded given current data that there may be potential impacts to groundwater quality due to BVWSD pumping from the proposed well field. BVWSD and the applicant have indicated they have additional data that was not available to staff at the time of this PSA/DEIS that may show there would be no impacts.

During construction, BMPs would be implemented to minimize the potential for erosion and minimize impacts on offsite areas, including the nearby canals. For portions of the CO_2 pipeline that cross the Outlet Canal, the Kern River Flood Control Channel, and the California Aqueduct, the HDD installation method and appropriate BMPs would be implemented.

The Project Site is not located in a designated floodplain. Pipelines that cross floodplain areas would be buried or installed using HDD technology at canal crossings.

The Project would contribute to overdraft of the Kern county subbasin and create water quality impacts within the aquifer. The project, therefore, could result in significant impacts to water resources.

1.1.17 Worker Safety and Health

Worker exposure to physical and chemical hazards would be minimized through adherence to appropriate engineering design criteria, implementation of appropriate safety and administrative procedures, use of personal protective equipment, and compliance with applicable health and safety regulations. By complying with all applicable LORS as well as implementing Project design features and Conditions of Certification, the Project would not result in significant impacts on worker safety and health.

U.S. DEPARTMENT OF ENERGY

Project Potential Cumulative Impacts

U.S. DEPARTMENT OF ENERGY - Project Potential Cumulative Impacts

Compliance with the National Environmental Policy Act requires an analysis of cumulative impacts for each action (40 Code of Federal Regulations [CFR] § 1508.25[c][3]). The Council on Environmental Quality defines a cumulative impact as "the impact on the environment which results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions" (40 CFR § 1508.7). Cumulative impacts can result from actions that have individually minor impacts, but that collectively impose significant impacts over a period of time. The U.S. Department of Energy considers a reasonably foreseeable action to be a future action that has a realistic expectation of occurring. These include (but are not limited to) actions under analysis by a regulatory agency, proposals being considered by state or local planners, plans that have begun implementation, or future actions that have been funded.

1.0 Past, Present, and Reasonably Foreseeable Future Actions

Past actions in the area include the construction, use, operation, and maintenance of the surrounding agricultural properties; of residential, commercial, and industrial structures; and of roads in the project vicinity. Ongoing and current projects are limited to the use and maintenance of the developed facilities in the project vicinity (e.g., ongoing maintenance of roads, agricultural activities). These past and current actions are assumed to have created the existing affected environment; therefore, the impacts of such actions are detailed in the subsections of the Preliminary Staff Assessment (PSA)/Draft Environmental Impact Statement (DEIS).

Based on California Energy Commission (ENERGY COMMISSION) requirements, reasonably foreseeable future development was considered in the context of specific projects proposed for development within 6 miles of the Hydrogen Energy California HECA Project Site. The predicted environmental impacts of reasonably foreseeable actions were considered together with those of the HECA Project to produce a description of the combined or cumulative environmental impacts. For the purpose of this analysis, a list of proposed projects, presented in Table 1-1, was obtained by URS Corporation from the Kern County Planning Department (URS, 2012).

In addition to the information provided by Kern County, a public record request was submitted to the San Joaquin Valley Air Pollution Control District (SJVAPCD), to evaluate cumulative impacts to air quality. Based on ENERGY COMMISSION requirements, the record request asked for a list of large stationary source projects that met the following criteria: 1) projects with greater than 5 tons of permitted emissions of any single criteria pollutant; 2) projects located within 6 miles of the Project Site; and 3) projects that have been recently permitted but did not start operation prior to 2009, or that are in the process of being permitted. The SJVAPCD identified the following facilities in the Project area that met criteria 2 and 3, but none met criteria 1:

- E-Z Trip Food Store Gas Station
- Stockdale 76 Gas Station

- Shiralian ENT INC, DBA E-Z TRIP-B/W Gas Station
- California Highway Patrol Fueling Station
- Buttonwillow Chevron Gas Station
- Mobil Mart Gas Station
- Rio Bravo Tomato Company LLC

Therefore, because the seven projects listed above are relatively minor sources, they were not required to be included in the Air Quality modeling cumulative analysis.

2.0 Cumulative Impacts Analysis

The potential cumulative impacts to resource areas are discussed below. If an action would have no or negligible direct or indirect impacts to a resource, that action is assumed to not contribute to any cumulative impact on that resource, and the resource topic relative to that action is not discussed further in this section.

Notably, the Project would have negligible impacts on Worker Safety and Health through implementation of standard industry practices. Therefore, the Project would not contribute to any cumulative impact regarding Worker Safety and Health, and no further evaluation of this topic is warranted.

Table 2-1 provides a discussion and summary of the cumulative impacts regarding each of the remaining resource disciplines. Additional details are provided in the cumulative impact analysis subsection for each resource topic of the PSA/DEIS. Section 3.0 provides the conclusions of the cumulative impact analysis based on Table 2-1.

3.0 Conclusions

Based on the analyses presented in Table 2-1, with implementation of Project design features and Conditions of Certification, the Project is not expected to have significant cumulative impacts. No further analysis regarding cumulative impacts is warranted.

4.0 References

DOE (U.S. Department of Energy), 2011. National Energy Technology Laboratory. Project Facts, Clean Coal Power Initiative (CCPI 3). Hydrogen Energy California Project: Commercial Demonstration of Advanced IGCC with Full Carbon Capture. November.

URS (URS Corporation), 2012. Amended Application for Certification for Hydrogen Energy California. May.

Table 1-1
Proposed Projects within 6 Miles of HECA Project Site

Case ID	Project Location	APN	Applicant	Case Type	Request	Acres	Use Type
10212	North and West of the Project Site; Intersection of Dairy Road and Adohr Road	159-030-06 159-070-03 159-130-11 159-020-16	Dykstra Dairies/David Albers	CUP	Conditional Use Permit to Establish a 1,061-Acre Dairy (121-Acre Dairy, 739 Acres of Liquid Waste Disposal/Spreading, and 201 Acres for Solid Waste Disposal/ Spreading) (Palm Ranch)	1,061	Agriculture
10660	Southeast Corner of 7th Standard Road and Brandt Road	463-030-12	Affentranger, Franz (Pine Dairy)	CUP	Conditional Use Permit to Establish a 589.35-Acre Dairy and 1,973.28-Acre Crop Area (Pine Dairy)	2,564	Agriculture
11392	Northwest Corner of Stockdale Highway and Enos Lane	104-291-10	Stockdale Investor, LLC/David Wood	GPA	General Plan Amendment From Resource – Intensive Agriculture (R-LA) and Service Industrial (SI) to Low/Medium-Density Residential (LMR) Max 10 Units/Net Acre	264	Residential – Assume Maximum of 2,640 Residential Dwelling Units
12698	Tracy Avenue, Buttonwillow	103-080-44	Rio Bravo Vista/ Mcintosh and Associates	PD	Precise Development for “La Quinta” Hotel	6.5	Commercial
12766	345 Driver Road	104-291-52	Petro Ready Mix/Pete Pedroza	PD	Precise Development for Concrete Batch Plant	78.2	Industrial

Table 1-1
Proposed Projects within 6 Miles of HECA Project Site

Case ID	Project Location	APN	Applicant	Case Type	Request	Acres	Use Type
11389; 11390	Highway 43 at Country Triangle Road	104-292-29	Stockbuilding Supply/ Klassen Corp	PD; ZV	Precise Development for Lumber Truss Manufacturing/Warehouse Includes Variance for Reduction of Parking, May Require General Plan Amendment of Circulation Element; Zoning Variance for Reduced Parking	26.6	Industrial
11484; 11708	Southwest Corner of Highway 58 and Highway 43	104-220-19	Cn Holdings By San Joaquin Engineering	ZCC; Exclusion	Zoning Change/Amendment to Estate Minimum Lot Size 1 Acre (E[1]) District, General `Commercial (C-2) District, and Precise Development (PD) Combining District; Exclusion from Agricultural Preserve #9	149.6	Mixed – Assume Maximum of 149 Residential Dwelling Units
9952; 9953	7626 Superior Road	104-012-15	Cooper, Michael and Cheryl/D and D	ZCC; Exclusion	Zoning Change/Amendment From Exclusive Agriculture (A) to Natural Resource 5 Gross Acre Minimum Lot Size (NR[5]) District; Exclusion from Agricultural Preserve	10	Industrial
10507	East Side of Enos Lane, 1 Mile North of Panama Lane		Kern Water Bank Authority/ D-Millazo	CUP	Conditional Use Permit to Establish a Public Agency Building		Commercial

Table 1-1
Proposed Projects within 6 Miles of HECA Project Site

Case ID	Project Location	APN	Applicant	Case Type	Request	Acres	Use Type
11620	North Side of Brite Road, 1 Mile East of Wasco Way	103-210-12	Brewer, Susan By Del Marter & Deifel	MOD	Modify (Lot Size Reduction) Lot Line Adjustment (#105-06)	1.4	Residential
11869	312 Cotton Avenue, Buttonwillow	101-041-12	Scott, Leland	Vacation	Summary Vacation		
11955	Olen Avenue, West of Enos Lane, Bakersfield	184-010-83	Jenkins, Larry/Joe Engel	PD	Precise Development for Warehouse and Mobile Home	20	Mixed
12374	Southwest of Interstate 5 and Enos Lane, Bakersfield`	160-130-23	Enos Lane Farm Properties LLC by Summit Engineering	ZV	Zoning Variance for Lot Size	40.7	
12408	West of Elk Hills Road, 1 Mile North of Highway 119	298-050-16	Kern County Planning Department	CUP	Conditional Use Permit, Establish SMARA Enforcement Proceedings	10	
12434	South Side Interstate 5, South of Enos Lane, Bakersfield		Enos Lane Farm/Summit Engineering	Vacation	Vacate Offer of Dedication/Public Road		

Table 1-1
Proposed Projects within 6 Miles of HECA Project Site

Case ID	Project Location	APN	Applicant	Case Type	Request	Acres	Use Type
13004	Southwest Corner of Stockdale Highway and Enos Lane, Bakersfield	160-010-02 160-010-07 160-010-19 160-010-21 160-010-22 160-010-59 160-010-60	AECOM	SPA	Circulation Amendment	640	
13218	31139 7th Standard Road, Buttonwillow	104-012-38	Swan, Murrel/ Bruce Anderson	CUP	Conditional Use Permit to Establish Agriculture Related Uses	24	Agriculture
13220	1 Mile West of Elk Hill Road South of Aqueduct	158-010-15	Kern County Planning Department	CUP	Conditional Use Permit, Establish SMARA Enforcement Proceedings	81	
13252	Elk Hills	298-170-27	ENXCO Development Corporation	CUP	Conditional Use Permit to Establish 7-MW Solar Project	47.3	Energy

Table 1-1
Proposed Projects within 6 Miles of HECA Project Site

Case ID	Project Location	APN	Applicant	Case Type	Request	Acres	Use Type
13263	Enos Lane and Baker Road, Bakersfield	104-011-12	Recurrent Energy by Seth Isreal	CUP	Conditional Use Permit to Establish 5-MW Solar Project	40	Energy
13264	Acacia Street and Cherry Avenue, Taft	298-190-15	Recurrent Energy by Seth Isreal	CUP	Conditional Use Permit to Establish 20-MW Solar Project	160	Energy
13311	22356 Rosedale Highway	104-230-26	Wattenbarger, Scott	PD	Precise Development for RV Storage	4.7	Light Industrial
13312	Shank Road	103-280-50 103-280-54 103-280-55 103-280-57 103-280-72	Urban Land Advisors/Matt Wade	Vacation	Vacation of Shank Road		
13479	Old Tracy Avenue and Interstate 5, Buttonwillow	103-080-45 103-080-46	Thomas Nguyen	GPA	General Plan Amendment from Other Facilities (3.3) and Light Industrial (7.1) to Service Industrial (7.2) to Develop a 1.3 Million Square Foot Distribution Facility		Industrial

Table 1-1
Proposed Projects within 6 Miles of HECA Project Site

Case ID	Project Location	APN	Applicant	Case Type	Request	Acres	Use Type
13489	Dustin Acres Road and Van Pelt Court, Taft	298-120-49 298-120-51	Van Pelt, Don	ZCC	Zoning Change/Amendment to Estate (E) Nonjurisdictional Land (1) Residential Suburban Combining District (RS) Mobile Home Combining District (MH)	7.5	Residential
13536	Enos Lane and Snow Road, Buttonwillow	104-012-26	Brandon G. Eaton	CUP	Conditional Use Permit to Establish a Rock Gravel Sand Distribution and Asphalt Batch Plant		Industrial
13605	14 Mile Area, West of Enos Lane		Plains Westside Pipeline/KC General Services	SP	Negative Declaration only for Pipeline Franchise		Industrial – 14-Mile Pipeline Section
13663	Southwest Corner of Isaac Road and Ferrel Street, Taft	298-300-15	Torres Sandra by Aaron Byrd	ZCC	Zoning Change/Amendment to Limited Agriculture District (A-1) or Residential Estate District (E[5]) Residential Suburban Combining District (RS)	40.1	Residential
13727	Northeast Corner of Brite Road and Parsons Street	103-200-10	Pierucci A&L Family Trust by Ruettgers & Schuler	ZV	Zoning Variance to Home-site Parcel	119.7	Residential
13729	28323 Highway 119, Dustin Acres	298-110-21 298-110-22	Harrington, Billy	CUP	Conditional Use Permit to Establish an Agricultural Supply Service		Commercial

Table 1-1
Proposed Projects within 6 Miles of HECA Project Site

Case ID	Project Location	APN	Applicant	Case Type	Request	Acres	Use Type
13772	7th Standard Road and Superior Road	104-012-03 104-012-06	First Solar Development Inc.	CUP	Conditional Use Permit to Establish a 20-MW Alternating Current Photovoltaic Solar Project		Energy
13835	20641 Tracy Avenue, Buttonwillow	103-280-49	Castro, Salvador	ZV	Zoning Variance to Expand Existing Pole Sign Area		Commercial
No Case ID	Occidental of Elk Hills Gas Plant		Occidental of Elk Hills		Authority to Construct (Air Permits) to Construct and Operate a Cryogenic Natural Gas Processing Plant		Oil and Gas

Source: URS, 2012

Notes:
APN Assessor's Parcel Number
CUP Conditional Use Permit
Exclusion Exclusion from Agricultural Preserve
GPA General Plan Amendment
MOD Modification
MW megawatt
PD Precise Development
SMARA Surface Mining and Reclamation Act
SPA Specific Plan Amendment
Vacation Vacate a Street, Highway, or Public Service Easement
ZCC Zoning Change/Amendment
ZV Zoning Variance

Table 2-1
Cumulative Impact Analysis

Resource	Contribution from the HECA Project	Contribution from Other Reasonably Foreseeable Projects	Total Cumulative Impacts	Conclusion
Air Quality	Project emissions, in combination with conservative background concentrations, would not cause a violation of any the CAAQS or NAAQS, and with mitigation measures, would not significantly contribute to the existing violations of the federal and state PM_{10} and $PM_{2.5}$ standards. In addition, all of the Project's operational emissions of PM_{10}, NO_X, VOCs, and SO_X would be offset to ensure a net air quality benefit. $PM_{2.5}$ emissions would be mitigated by the PM_{10} ERCs, because $PM_{2.5}$ is a subset of PM_{10}. Because NO_2 impacts from HECA exceeded the 1-hour SIL, a regional analysis was conducted, and the impacts from the major sources in the region, plus background, plus the HECA project would not cause a violation of the NAAQS.	Based on the SJVAPCD list, all of the sources of emissions emit less than the 5 tons/year emission threshold for any criteria pollutant; and no sources with emissions greater than 5 tons/year have been permitted in the past few years, or would be permitted in the foreseeable future, within 6 miles of the Project Site. Emissions from activities associated with the operation and construction of EOR at OEHI would occur at the same time as the HECA Project. OEHI prepared an environmental assessment that demonstrated that impacts from the OEHI project would not be significant with mitigation. During the construction phase, Conditions of Certification would be implemented to minimize fugitive dust and equipment exhaust. OEHI operations would provide ERCs to mitigate emissions from permitted sources. The OEHI operations and construction would move	The potential impacts from HECA and nearby sources were analyzed, and it was determined that HECA would not would not cause a violation of a CAAQS or NAAQS, or significantly contribute to existing violations of the federal and state PM_{10} and $PM_{2.5}$ standards.	Significant adverse cumulative impacts on air quality are not expected.

Table 2-1
Cumulative Impact Analysis

Resource	Contribution from the HECA Project	Contribution from Other Reasonably Foreseeable Projects	Total Cumulative Impacts	Conclusion
		throughout the site as needed to access the wells needing EOR. The potential air impacts from OEHI would also move as the sources move, and may be as close as 4 miles and as far as 15 miles from the HECA property line. Because the OEHI impacts are not significant, and because the emissions are far from the HECA Project and variable in location, it is expected that the emissions from OEHI would not cause a cumulatively significant impact to air quality with the HECA Project. Therefore, because no large nearby sources were identified, and because OEHI is not expected to be cumulatively significant with HECA, cumulative modeling for CEQA was not necessary.		
Biological Resources	No threatened or endangered plant or wildlife species were identified on the HECA Project Site. However, construction, operation, and	Development of the proposed projects would potentially have similar adverse impacts to the same species affected by the HECA Project. All of the potential projects in the vicinity	Cumulative impacts of the Project in association with impacts of the proposed projects would contribute to a cumulatively adverse	Significant cumulative impacts to biological resources are not expected to

Table 2-1
Cumulative Impact Analysis

Resource	Contribution from the HECA Project	Contribution from Other Reasonably Foreseeable Projects	Total Cumulative Impacts	Conclusion
	decommissioning of the HECA Project, including associated linears (pipelines, rail spurs, transmission lines, etc.) are likely to adversely affect the following species: blunt-nosed leopard lizard, giant kangaroo rat, Tipton kangaroo rat, San Joaquin kit fox, Buena Vista Lake shrew, Nelson's antelope squirrel, and Swainson's hawk. Impacts are associated with temporary and permanent loss of habitats and mortality of individuals. Avoidance and minimization measures would be implemented that would reduce potential take of these species and provide long-term beneficial impacts. These measures include actions that would avoid or minimize the potential for mortality, disturbance, habitat degradation, and other	of the Project area would be required to comply with applicable federal, state, and local regulatory requirements that also protect state and federally listed wildlife species. Impacts from these projects are expected to be mitigated through the regulatory pathways that would reduce their cumulative impacts. Construction of other projects could adversely affect waters of the United States or waters of the State; however, impacts from these projects are expected to be mitigated through the regulatory pathways that would reduce their cumulative impacts.	impact to the identified species. Implementation of avoidance and conservation measures, as well as habitat compensation as appropriate and as required by the regulatory agencies, would substantially reduce the potential for adverse impacts on the affected species. Compliance with federal, state, and local regulatory requirements that protect federally and state listed wildlife species would reduce cumulative impacts. Projects that place fill in jurisdictional wetlands and nonwetland waters of the United States require either an individual or a nationwide permit from the USACE. Projects that affect waters of the State would be required	occur.

Table 2-1
Cumulative Impact Analysis

Resource	Contribution from the HECA Project	Contribution from Other Reasonably Foreseeable Projects	Total Cumulative Impacts	Conclusion
	potential adverse impacts on the species. Additional conservation measures would restore and provide permanent protection and enhancement of habitats for affected species. Collectively, when implemented, these measures would avoid jeopardy of the affected species, and improve opportunities for recovery of the species. The Project design has included avoidance measures so that construction and operation would avoid nearly all of the potential jurisdictional waters in the Project Area. The Project is expected to permanently affect less than 0.2 acre of waters of the United States and less than 0.14 acre of waters of the State. The Project would obtain a nationwide permit from the USACE, and a Lake and Streambed		to comply with State permitting requirements. Because all projects would need to comply with the appropriate regulatory requirements, cumulative impacts on wetlands would not be significant.	

Table 2-1
Cumulative Impact Analysis

Resource	Contribution from the HECA Project	Contribution from Other Reasonably Foreseeable Projects	Total Cumulative Impacts	Conclusion
	Alteration Agreement from CDFW to cover these impacts. With implementation of Conditions of Certification, impacts of the Project on biological resources would not be significant.			
Climate	A key objective of the Project is to mitigate impacts related to climate change by dramatically reducing GHG emissions relative to those emitted from conventional coal-fuel–fired power generation and nitrogen-based fertilizer manufacturing. This reduction would be achieved by capturing and sequestering CO_2 emissions. HECA would emit less than 400 pounds of CO_2 per MWh, and would capture and sequester approximately 90 percent of the carbon from the syngas. (Energy Commission staff analyses indicate that HECA would emit 1,000 to 1,120 lb CO_2 per MWh during early operations and 788 to 843 lb CO_2 per	Some GHG emissions would be emitted from the OEHI Project during EOR, and from the reasonably foreseeable future sources near the HECA Project.	GHG emissions and climate change by nature are a cumulative issue. HECA would emit GHGs, but significantly less than similar conventional projects. HECA would emit less than 400 pounds of CO_2 per MWh, which is significantly less than the state or national average for power production facilities. (Energy Commission staff analyses indicate that HECA would emit 1,000 to 1,120 lb CO_2 per MWh during early operations and 788 to 843 lb CO_2 per MWh if and when it reaches mature operations, expected after about two years of early	Significant cumulative impacts to climate change are not expected to occur. The development of the clean coal technology and demonstration of CCS at this scale would pave the way for future low carbon projects; therefore, the HECA project provides a cumulative benefit toward minimizing

Table 2-1
Cumulative Impact Analysis

Resource	Contribution from the HECA Project	Contribution from Other Reasonably Foreseeable Projects	Total Cumulative Impacts	Conclusion
	MWh if and when it reaches mature operations, expected after about two years of early operations).		operations)	climate change. If HECA is constructed and attains mature operations, it would demonstrate that coal facilities could be carbon-equivalent to natural gas facilities.
Cultural Resources	Archaeological resources have been identified in and adjacent to the project area of analysis/area of potential effects (PAA/APE), and Project-related ground disturbance could have adverse impacts on these resources. Although staff has proposed Conditions of Certification to reduce the significance of identified impacts, staff needs additional information from the applicant to prepare a conclusive analysis of project impacts on cultural resources. All buildings (built environment resources)	Construction of other projects could impact cultural resources within the Project area. Staff requires additional information from the applicant concerning cultural resources before it can draw conclusions related to cumulative impacts on cultural resources.	Staff cannot evaluate the cumulative impacts from the Project on the regional cultural resources until the applicant provides additional, staff-requested information on cultural resources	Inconclusive, to be analyzed in the FSA/FEIS.

Table 2-1
Cumulative Impact Analysis

Resource	Contribution from the HECA Project	Contribution from Other Reasonably Foreseeable Projects	Total Cumulative Impacts	Conclusion
	constructed before 1964 within the study area were recorded and evaluated. Two historic buildings/structures that qualify as significant cultural resources are located in the PAA/APE. The proposed project would not affect these two resources, however.			
Electrical Transmission	The Project would provide approximately 300 MW of new, low-carbon baseload electric-generating capacity during operations. This would result in beneficial impacts associated with electrical transmission.	Development projects would increase the demand on the electrical systems in the Project Area and in the region.	The Project would supply electricity in the Project Area to assist in meeting the increased demand from other projects.	Significant cumulative impacts to electrical transmission are not expected to occur.
Geological and Mineral Resources	Drawdowns associated with Project-specific pumping from BVWSD's well field are expected. Localized subsidence could result from the proposed project's pumping. A monitoring program accompanied by an action plan is recommended. The CO_2 captured by the Project would enable	Development projects are not in an area mapped as having measured land subsidence or hydro-compaction. Based on the location of the proposed projects identified in Table 1-1, and/or on the fact that these projects are not expected to withdraw large volumes of groundwater from the same aquifer, development projects in the Project area would not result in significant subsidence	The Project could contribute to a cumulatively significant impact associated with subsidence from groundwater withdrawal. Mitigation is proposed. CO_2 capture, injection, and oil recovery however is not expected to contribute to subsidence.	Cumulative impacts to geological and mineral resources can be mitigated.

Table 2-1
Cumulative Impact Analysis

Resource	Contribution from the HECA Project	Contribution from Other Reasonably Foreseeable Projects	Total Cumulative Impacts	Conclusion
	geologic storage at a rate of approximately 3 million tons of CO_2 per year, and would increase domestic oil production (DOE, 2011).	impacts. None of the reasonably foreseeable projects identified in this analysis would result in CO_2 capture or oil recovery. Therefore, none of these projects would contribute to CO_2 capture or increase in domestic oil production.		
Hazardous Materials Management	The Project would store anhydrous ammonia in double-integrity, steel-refrigerated storage tanks for maximum safety. Based on the quantity of anhydrous ammonia to be stored, the Project would be required to comply with federal and state Risk Management Plan and Process Safety Management regulations and Conditions of Certification. OCA modeling results for anhydrous ammonia demonstrated that under a worst-case scenario, the release of anhydrous ammonia would not extend beyond the Project Site boundary. HECA is not producing,	The projects listed in Table 1-1 are not expected to store large quantities of methanol, CO_2, hydrogen sulfide, or other hazardous chemicals used by HECA in substantial quantities, other than anhydrous ammonia. Anhydrous ammonia is frequently used by the agriculture industry as a fertilizer component, and is applied throughout agricultural fields. Because ammonia is applied throughout agricultural fields, mobile ammonia tanks can be potentially found in various locations of an agricultural field. The facilities that use hazardous chemicals are highly regulated through federal, state, and local	The project in combination with the other cumulative projects would not result in adverse cumulative hazard risks.	Significant cumulative impacts from hazardous materials are not expected to occur.

Table 2-1
Cumulative Impact Analysis

Resource	Contribution from the HECA Project	Contribution from Other Reasonably Foreseeable Projects	Total Cumulative Impacts	Conclusion
	storing, or using dry ammonium nitrate, and has specifically chosen a liquid form to avoid explosion concerns. Therefore, the potential impacts from the use and storage of anhydrous ammonia by the Project would not be significant. No other hazardous materials stored or used at the Project Site are anticipated to produce impacts with respect to hazards. Consequently, it is anticipated that the potential impacts from the operation of the Project would not be significant.	requirements, and would be required to comply with similar regulatory requirements that depend on the quantities stored. Therefore, impacts from these projects are expected to be mitigated through the regulatory pathways that would reduce their impacts.		
Land Use	The HECA Project is consistent with adopted General and Specific Plans and the Kern County Zoning Ordinance, and would not conflict with existing land uses in the vicinity. The Project would result in the conversion of the Project Site from agricultural to a power-generating plant and to fertilizer manufacturing and	Development of the proposed projects would result in physical changes that would introduce new land uses. Some of these projects could convert prime farmland to other uses and require Williamson Act cancellation, but these would be a small percentage of the overall acreage of Kern County Prime Farmland. Although developments would result in	The Project and other proposed future projects are expected to be consistent with adopted General and Specific Plans and zoning designations and would not conflict with existing land uses in the Project vicinity. Therefore, the Project in combination with other development	Significant cumulative impacts to land use are not expected to occur.

Table 2-1
Cumulative Impact Analysis

Resource	Contribution from the HECA Project	Contribution from Other Reasonably Foreseeable Projects	Total Cumulative Impacts	Conclusion
	storage use (agricultural use only). This area represents approximately 0.07 percent of the 608,789 acres of Kern County Prime Farmland inventoried in 2010. Existing farmland would also be converted for the construction of the railroad spur, electrical transmission line, PG&E gas metering station, and switching station. Construction would temporarily disturb areas, including land required for construction laydown and installation of underground offsite linears. Based on the small percentage of farmland affected by the Project and recommended Conditions of Certification, it would not result in significant impacts to agricultural lands and activities.	noticeable physical changes to the vicinity, such changes would not result in a significant cumulative land use impacts because the uses would be required to be consistent with surrounding development and adopted General and Specific Plans and zoning designations.	projects in the study area would not significantly result in adverse impacts to land use.	
Noise and Vibration	Noise emissions resulting from the construction and operation of the HECA Project would not be significant, and would comply with the Kern	Based on the proximity to the HECA Project Site, the dairy farm was identified as a future project that could potentially influence ambient levels at noise sensitive receptors in the	Based on the results of cumulative noise modeling for the Project and dairy farm operations, the Project and dairy farm are not	Significant cumulative impacts from noise and vibration are not expected to

Table 2-1
Cumulative Impact Analysis

Resource	Contribution from the HECA Project	Contribution from Other Reasonably Foreseeable Projects	Total Cumulative Impacts	Conclusion
	County noise standard.	Project area. Although no details are currently available for this development, noise from dairy operations is estimated to be in the range of 75 to 85 dB (unweighted decibels); this is approximately equivalent to 57 to 67 dBA. Based on expected levels of onsite dairy noise, and in consideration of the distances to the nearest sensitive receptors, the dairy facility is expected to contribute negligible, if any, additional noise levels to the environment around the HECA Project Site. For potential Project operations noise impacts to the future dairy facility, the 121 acres of cow yards and milking facilities were assumed, as a worst case, to be located immediately to the west of the HECA Project Site, across Dairy Road. Project modeling for this location indicated an expected daytime contribution of 51 dBA (which is approximately equivalent to 68 dB unweighted). The majority of Project noise sources would be more than	expected to result in cumulative noise impacts on sensitive receptors in the study area. Furthermore, Project operations are not expected to have significant impacts on the future dairy facility.	occur.

Table 2-1
Cumulative Impact Analysis

Resource	Contribution from the HECA Project	Contribution from Other Reasonably Foreseeable Projects	Total Cumulative Impacts	Conclusion
		0.5 mile away; and, based on predicted Project contributions, the estimated dairy facility self-generated noise is expected to eclipse the Project equipment noise levels by a difference of about 6 dB or more dB. Therefore, noise impacts from the Project are not expected to be significant at the closest potential dairy facility.		
Paleontological Resources	Any Project-related ground disturbance could have adverse impacts on paleontological resources; however, with implementation of the proposed mitigation program, and compliance with Conditions of Certification, impacts would not be significant.	Construction of other projects could impact paleontological resources in the Project area. All of the potential projects in the vicinity of the Project area would be required to comply with state and local regulatory requirements. Impacts from these projects are expected to be mitigated through the regulatory pathways that would reduce their cumulative impacts.	Cumulative impacts from the Project on the regional paleontological resources would not be significant with implementation of Conditions of Certification.	Significant cumulative impacts to paleontological resources are not expected to occur.
Public Health	The emissions of TACs were modeled to determine the potential health risks to nearby residents and workers. The model predictions showed that the	There are no large sources of TAC/HAPs or criteria pollutants near the Project Site, and none are known to be proposed or under development.	Because there are no large nearby sources, and the project would not exceed any of the health thresholds, the Project in combination	Significant cumulative impacts to public health are not expected to occur.

Table 2-1
Cumulative Impact Analysis

Resource	Contribution from the HECA Project	Contribution from Other Reasonably Foreseeable Projects	Total Cumulative Impacts	Conclusion
	HECA project impacts would not exceed any of the health thresholds; therefore, the project would not cause a significant adverse health risk.		with the other cumulative projects would not result in adverse cumulative health risks. . However, Energy Commission staff notes that a facility such has HECA has not previously been built or operated in the United States and that careful monitoring is needed to ensure public health and worker safety are not adversely affected by the project.	

Table 2-1
Cumulative Impact Analysis

Resource	Contribution from the HECA Project	Contribution from Other Reasonably Foreseeable Projects	Total Cumulative Impacts	Conclusion
Socioeconomics and Environmental Justice	The Project would not result in significant direct, indirect, or cumulative adverse socioeconomic impacts on project area housing, schools, law enforcement services, and parks. The project would not induce substantial population growth, displacement of population, or demand for housing and public services. The Project would result in beneficial impacts to populations in the short term from increased employment opportunities during construction. Several technical areas have identified potential significant unmitigated impacts from the construction and operation of the HECA Project, but have not concluded if their significant impacts would remain unmitigated. Therefore, based on the information available to staff, these impacts could have adverse or disproportionate impacts on an environmental justice population.	Beneficial impacts to populations in the short term from increased employment opportunities would result during the construction phases of the cumulative projects. Based on **Socioeconomics Table 14** which identifies a list of cumulative projects that could impact socioeconomics resources, staff identified 17 industrial, infrastructure, and natural resource projects with labor needs that could potentially overlap with those of the HECA power plant component, possibly affecting construction workforce availability, thus creating a demand for workers that may not be met by the labor force in Kern County. With the information available on the 17 cumulative projects, staff cannot conclude on whether these projects would or would not have an adverse or disproportionate impact on an environmental justice population.	Staff concluded that none of the projects considered together with the Project would create cumulative impacts with regard to labor supply. Staff, thereby, concludes that the proposed Project would not result in any significant and adverse cumulative impacts on population, housing, schools, parks and recreation, or law enforcement. As several technical areas have identified potential significant unmitigated impacts from the construction and operation of the HECA Project, but have not concluded if their significant impacts would remain unmitigated, staff (based on the available information)_consider these impacts could have an adverse or disproportionate impacts on an environmental justice population .	Significant cumulative impacts to socioeconomics are not expected to occur. At this time, several technical areas have identified potential significant unmitigated impacts from the construction and operation of the HECA Project. Staff has not concluded if these impacts would remain unmitigated. Therefore, there could be disproportionate impacts on an environmental justice populationSignificant cumulative impacts to socioeconomics, minorities, or low-income populations are not expected to occur.

Table 2-1
Cumulative Impact Analysis

Resource	Contribution from the HECA Project	Contribution from Other Reasonably Foreseeable Projects	Total Cumulative Impacts	Conclusion
	on an environmental justice population.		.	
Soils	During construction, the potential for erosion would be managed with the implementation of BMPs to minimize impacts, and compliance with Conditions of Certification. After construction, the potential for erosion would be minimal due to surface coverage and stormwater management.	Construction of the cumulative projects would have the potential to result in soil erosion. However, similar to the Project, other developments would have to comply with local regulations and implement BMPs to reduce erosion impacts. In the long term, overall soil loss in the area would be reduced due to the change in land use from agricultural uses to developed areas, such as commercial and industrial uses.	Soil loss resulting from the construction and operation of the Project and other development projects would be minimal. Therefore, cumulative impacts on soils would not be significant.	Significant cumulative impacts to soils are not expected to occur.
Traffic and Transportation	During Project construction and operations, the Project study area would experience increases in traffic associated primarily with worker commute trips, material and equipment deliveries, products truck trips, and operation and maintenance trips. With implementation of Conditions of Certification, Project impacts related to traffic would not be	Based on information provided by Kern County Road's Department staff, the Project's construction traffic would not coincide with any potential future project in the immediate vicinity of the HECA Project Site, so the Project's contribution to cumulative traffic impacts during construction would not be considered significant. For Project operations, the traffic modeling conducted to	The results of the traffic analysis showed that the Project construction and operational traffic, combined with future ambient traffic growth, would not result in significant cumulative impacts to traffic and transportation.	Significant cumulative impacts to traffic and transportation are not expected to occur.

Table 2-1
Cumulative Impact Analysis

Resource	Contribution from the HECA Project	Contribution from Other Reasonably Foreseeable Projects	Total Cumulative Impacts	Conclusion
	significant.	evaluate Project impacts assumed a conservative 2 percent annual ambient traffic growth to account for development that may come online in the study area. The projects listed in Table 1-1 are expected to be captured in this 2 percent growth estimate.		
Visual Resources	The Project would potentially result in significant impacts at Key Observation Point No. 1; however, impacts would be reduced to less than significant with the implementation of Conditions of Certification. Although the Project is expected to change the existing character of the site, significant impacts to the scenic attractiveness of the Visual Sphere of Influence as a whole are not anticipated due to existing industrial and agricultural activities.	Development projects within the VSOI can be characterized primarily as zone changes, lot line/property line adjustments, roadway improvements, home remodeling, agricultural supply services, or activities related to agriculture or to oil and mining operations. Based on the location of the proposed future projects identified in Table 1-1, no new residential or recreational uses are proposed that may generate additional sensitive visual receptors. A new dairy operation is planned across the road from the HECA Project Site, situated on the north side of Adohr Road and the west side of Dairy Road. The Project area is generally characterized by agricultural	The dairy facilities would be visually subordinate to the Project, and the adjacency of the two projects would not result in significant impacts for viewers in the area. The addition of the Project would alter the existing landscape and visual setting at the Project Site. However, the addition of any of the other listed projects, when considered in combination with the Project, would not cumulatively create significant impacts to the visual setting within the VSOI.	Significant cumulative impacts to visual resources are not expected to occur.

Table 2-1
Cumulative Impact Analysis

Resource	Contribution from the HECA Project	Contribution from Other Reasonably Foreseeable Projects	Total Cumulative Impacts	Conclusion
		activities, oil extraction, and other industrial facilities. Therefore, the dairy facilities would not significantly contribute to the alteration of the landscape in the Project area.		
Waste Management	Based on the remaining capacity and estimated closure dates of the Class III landfills in California, the nonhazardous wastes that cannot be recycled are expected to significantly impact the capacity of the Kern County Class III landfills. The project has the potential to consume as much as ten percent of Kern County's Class III landfill capacity. An undefined percentage of gasification solids generated from the Project are expected to be used for beneficial reuse, and not disposed in a landfill. The gasification waste could be excluded from hazardous waste regulations (i.e., 40 CFR Section 261.4 (b) (7) (ii) (F)	Future foreseeable projects are estimated to increase the amount of waste generated in the Project Area. The projects would be required to comply with Kern County's recycling requirements. The waste management impacts of the proposed project, in combination with past, present and reasonably foreseeable projects in the area would be cumulatively considerable The project has the potential to consume as much as ten percent of Kern County's Class III landfill capacity. The large quantity of waste would significantly impact Kern County landfills and possibly compromise the county's compliance with Public Resources Code section 40000 et seq and implementing	Future foreseeable projects, including the Project, would generate waste. There are, however, adequate recycling facilities and landfill capacities to dispose of the waste from the Project over the next 25 years. Waste generated by the Project would add to the total waste generated in Kern County and in California, Unless comprehensive waste diversion or recycling programs are implemented the large quantity of waste would significantly impact Kern County landfills and possibly compromise the county's compliance with Public Resources Code	Significant cumulative impacts from waste management are expected to occur.

Table 2-1
Cumulative Impact Analysis

Resource	Contribution from the HECA Project	Contribution from Other Reasonably Foreseeable Projects	Total Cumulative Impacts	Conclusion
	and Title 22 CCR Section 66261.4(b) (5) (A). However, prior to acceptance of the gasification solids into a Kern County owned and operated landfill the solids must be analyzed and classified as non-hazardous or hazardous waste. If the solids are determined to be hazardous, the amount of hazardous waste would be burdensome to the State of California and disposal would be costly to the applicant.	regulations.	section 40000 et seq and implementing regulations.	
Water Resources	The Project would use groundwater from BVWSD's Brackish Groundwater Remediation Project for process water demands. Annual pumping for the Project is expected to average 7,430 afy, with a maximum of 7,500 afy per the HECA/BVWSD agreement. Construction activities could affect surface water quality of nearby canals through	The cumulative development projects include agriculture, residential, and commercial projects that would have varying water demands. Water would be provided by private groundwater wells and/or the local water districts that provide water from groundwater and surface water. The projects' demands are expected to also contribute to overdraft of the Kern county subbasin. Therefore, a cumulative impact	Overall, Project-specific pumping would contribute to overdraft of the Kern county subbasin. Therefore, a cumulative impact to local water resources is expected.	Significant cumulative impacts to water resources could occur and would require mitigation.

Table 2-1
Cumulative Impact Analysis

Resource	Contribution from the HECA Project	Contribution from Other Reasonably Foreseeable Projects	Total Cumulative Impacts	Conclusion
	inadvertent spills or discharges. Construction activities could also increase the potential for erosion and uncontrolled runoff of stormwater contaminated with sediments or other pollutants that could impact surface water quality and sedimentation. These potential impacts would be prevented or reduced to a level of less than significant with the implementation of BMPs, a final DESCP, construction SWPPP, and compliance with all applicable erosion and stormwater management LORS and Conditions of Certification. During operations, the Project would introduce impervious surfaces that would increase the amount of stormwater runoff and would use and store materials that could contaminate stormwater. The Project would be constructed in such a way	to local water resources is expected . The cumulative development projects have the potential to generate water quality impacts during construction and operation activities. However, it is expected that existing programs, policies, and regulatory requirements would prevent and/or minimize the potential water quality impacts to a level below a substantial impact.		

Table 2-1
Cumulative Impact Analysis

Resource	Contribution from the HECA Project	Contribution from Other Reasonably Foreseeable Projects	Total Cumulative Impacts	Conclusion
	that stormwater runoff would be contained in retention basins and reused at the Project Site. Wastewater would be discharged to the ZLD unit. The Project would implement BMPs to properly store and handle all materials and prevent spills. Therefore, there would be no discharges to surface waters and no impacts to surface water quality.			

Notes:

afy acre-feet per year
BMP best management practice
BVWSD Buena Vista Water Storage District
CAAQS California Ambient Air Quality Standards
OCA Offsite Consequence Analysis
CCS carbon capture and sequestration
CDFW California Department of Fish and Wildlife
CEQA California Environmental Quality Act of 1970
CO_2 carbon dioxide
dB decibel
dBA A-weighted decibel
DESCP drainage, erosion, and sediment control plan
EOR enhanced oil recovery
ERC emissions reduction credits
GHG greenhouse gas
NAAQS National Ambient Air Quality Standards
NO_X oxides of nitrogen
NO_2 nitrogen dioxide
OEHI Occidental of Elk Hills, Inc.
PG&E Pacific Gas and Electric Company
PM_{10} particulate matter less than 10 microns in diameter
$PM_{2.5}$ particulate matter less than 2.5 microns in diameter
SIL Significant Impact Level
SJVAPCD San Joaquin Valley Air Pollution Control District
SO_X oxides of sulfur
SWPPP Storm Water Pollution Prevention Plan
syngas synthesis gas
TAC toxic air contaminant

Table 2-1
Cumulative Impact Analysis

Resource	Contribution from the HECA Project	Contribution from Other Reasonably Foreseeable Projects	Total Cumulative Impacts	Conclusion

HAP hazardous air pollutant
HECA Hydrogen Energy California
LORS laws, ordinances, regulations, and standards
MW megawatt
MWh megawatt hour
USACE United States Army Corps of Engineers
VOC volatile organic compound
VSOI visual sphere of influence
ZLD zero liquid discharge

U.S. DEPARTMENT OF ENERGY

Irreversible or Irretrievable Commitments of Resources

U.S. DEPARTMENT OF ENERGY - Irreversible or Irretrievable Commitments of Resources

A commitment of resources is irreversible when the primary (direct) or secondary (indirect) impacts from the use limit the future options for that resource. Irreversible commitments of resources refer to the use or consumption of a resource that cannot be reversed except over a very long time period (e.g., minerals). An irretrievable commitment of resources refers to the use or consumption of resources that is neither renewable nor recoverable for use by future generations and that cannot be restored. This commitment can refer to the use of non-renewable resources such as cultural resources, and the expenditure of labor or funds that, when used, would not be available for future use.

The No Action Alternative would not directly require the commitment of human or fiscal resources. However, this alternative fails to achieve all of the Project objectives related to production of energy, advancement of technology, and enhancement of energy security. The No-Action Alternative would not contribute to DOE goals of accelerating advanced emission controls and demonstrating new coal technologies that capture and beneficially use CO_2. In the long run, this alternative would not provide environmental benefits with regard to greenhouse gases, and would not help California meet its obligations under AB 32, SB 1368, and AB 1925.

The Action Alternatives would each involve irreversible or irretrievable commitment of resources, including the materials, energy, labor, and funds required during construction and operation. Implementation of Conditions of Certification, identified for this Project would minimize these commitments.

Non-renewable and irretrievable fossil fuels and construction materials (e.g., petroleum) would be required for both construction and operation. Use of raw building materials would be an irretrievable commitment of resources from which these materials were produced. Consumption or use of widely available materials such as gasoline and cement would not be anticipated to result in shortages.

Resources that would be irreversibly used during the construction of the Project include land and raw materials. Areas needed for construction of the Project and the associated linear facilities would be modified (e.g., cleared, graded, filled) to meet Project design requirements. The land resources needed would be physically altered, and the alteration of these land resources would constitute a permanent commitment of land for the life of the Project to a developed use and would decrease the amount of open/ agricultural land available for other uses. Access to lands in the Project Site would also be limited to authorized personnel, thus limiting the use of those lands for other uses.

Construction and operation would also result in an irreversible loss of biological resources, including loss of habitat and individual plants and animals which could be destroyed or displaced during construction and operation activities. The direct mortality of wildlife would be an irreversible impact and the loss of habitat would be an irretrievable impact.

Cultural and paleontological resources are non-renewable, and any disturbance of these resources from the action alternatives would constitute and irreversible and irretrievable commitment.

Construction and operation of the Project would result in an irretrievable commitment of resources such as non-renewable fuels to generate power and operate equipment and vehicles. Resources consumed during operation would include diesel oil, fuel oil, and gasoline.

An irretrievable expenditure of labor would occur during both construction and operation for all action alternatives. Funding would also be committed as part of any of the action alternatives, would not be available for other uses, and would therefore be irretrievable. Labor would also irreversibly and irretrievably be committed during preparation and creation of the construction materials.

Although the implementation of the action alternatives would result in the commitment of resources as described above, the alternatives would allow for the addition of a nominal 300 megawatts of baseload low-carbon power to the grid, provide environmental benefits with regard to greenhouse gases (among others), and help California meet its obligations under AB 32, SB 1368, and AB 1925.

1.1 THE RELATIONSHIP BETWEEN SHORT-TERM USES OF THE ENVIRONMENT AND LONG-TERM PRODUCTIVITY

This section addresses the relationship between short-term uses of the environment and the maintenance and enhancement of long-term productivity.

The No Action Alternative would not result in short-term uses of the environment. However, this alternative fails to achieve all of the Project objectives related to production of energy, advancement of technology, and enhancement of energy security. In the long run, this alternative would not provide environmental benefits with regard to greenhouse gases, nor help California meet its obligations under AB 32, SB 1368, and AB 1925.

Regardless of the Action Alternative, short-term uses of the environment would occur as a result of construction activities. These uses include impacts on air, noise, soils, water, and transportation resources. These short-term impacts would be minimized through the use of Best Management Practices and through the implementation of Conditions of Certification described for this Project. In addition, these short-term uses would allow for long-term productivity of several resources, as discussed below.

Some greenhouse gases would be emitted during construction and operation of the Project. However, implementation of the Project would result in long-term greenhouse gas benefits by dramatically reducing average annual greenhouse gas emissions relative to those emitted from a conventional coal-fueled power plant and nitrogen-based-product manufacturing facility by capturing and sequestering CO_2 emissions.

Short-term use of the construction labor force would result in substantial long-term productivity in the economic environment, given the short- and long-term benefits to local and regional employment and tax revenue.

Short-term commitment of non-renewable and irretrievable fossil fuels and energy would be required for both construction and operation, as discussed above. However, implementation of the Project would conserve domestic energy supplies and enhance energy security by using coal and a byproduct from the oil-refining process (petcoke) to generate electricity and by enhancing production of domestic petroleum reserves that may otherwise be unrecoverable.

In the long term, implementation would support the Project's objective to produce hydrogen for low-carbon baseload power generation and nitrogen-based products, and demonstrate carbon capture and sequestration on a commercial scale. If HECA is constructed and attains mature operations, it would demonstrate that coal facilities could be carbon-equivalent to natural gas facilities The Project would support the DOE's Clean Coal Power Initiative, to further the commercialization of clean coal technologies that advance efficiency, environmental performance, and cost competitiveness well beyond the level of technologies that are currently in commercial service. The Project would contribute an approximately 300-megawatt output of low-carbon baseload electricity to the grid during operations, and thus feed major load sources while providing environmental benefits regarding greenhouse gases (among others) and helping California to meet its obligations under California AB 32 and AB 1925, California SB 1368, and California Executive Orders S-7-04 and S-3-05. Energy Commission staff understands that HECA is designed to generate up to 431 megawatts (MW) of gross power but the overall project is expected to provide only up to 52.5[1] MW of new base load electricity to the grid. If other older coal-fueled power plants were replaced with newer plants similar to the Project's, the total domestic and international emissions of pollutants could be reduced, and there will be an increase in the efficient use of non-renewable resources.

If implemented, once the Project reaches mature operations it would contribute to long-term positive impacts through the reduction of CO_2 emissions per megawatt generation. In addition, the integrated production of nitrogen-based products would enhance the production and availability of nitrogen-based products by producing approximately 1 million tons per year of low-carbon nitrogen-based products (including Urea, Urea Ammonium Nitrate, and anhydrous ammonia) for regional markets, which will result in long-term productivity increases.

[1] This net power value includes all project-wide power generation and power consumption sources, including the power consumption of the third-party owned air separation unit and the power consumption required by the OEHI CO_2 EOR component.

U.S. DEPARTMENT OF ENERGY

HECA Project Permit/Approval List

HECA Project Permit/Approval List

Resource Area	Permit/Approval	Local/State/ Federal	Agency
General	Preliminary Staff Assessment/Draft Environmental Impact Statement	State/Federal	CEC/DOE
	Final Staff Assessment/Final Environmental Impact Statement	State/Federal	CEC/DOE
	Commission Decision/Record of Decision	State/Federal	CEC/DOE
	Class II injection wells under the Underground Injection Control program	Federal	Division of Oil, Gas, and Geothermal Resources
Air Quality	Preliminary Determination of Compliance	Regional	SJVAPCD
	Final Determination of Compliance	Regional	SJVAPCD
	Authority to Construct	Regional	SJVAPCD
	Permit to Operate	Regional	SJVAPCD
	Prevention of Significant Deterioration review	Federal	SJVAPCD
	General Conformity Determination	Federal	SJVAPCD and DOE
	Title IV Acid Rain Permit (Clean Air Act)	Federal	SJVAPCD
	Title V Operating Permit (Clean Air Act)	Federal	SJVAPCD
Biological Resources	Biological Opinion (Section 7 of federal Endangered Species Act)	Federal	USFWS
	Incidental Take Permit (California Fish and Game Code Section 2081)	State	CDFW
	Lake and Streambed Alteration Agreement (California Fish and Game Code Section 1600)	State	CDFW
	404 Nationwide Permit	Federal	U.S. Army Corps of Engineers
	401 Water Quality Certification/ Waste Discharge Requirements	State	RWQCB

Resource Area	Permit/Approval	Local/State/ Federal	Agency
Cultural Resources	Section 106 Compliance	Federal	State Historical Preservation Office
Hazardous Materials	Permit for Construction Activities – includes a copy of the Construction Injury and Illness Prevention Plan and Code of Safe Practices	State	Cal/OSHA
	Tower Crane Permit	State	Cal/OSHA
	Permit to Operate Pressure Vessels	State	Cal/OSHA
	Elevator and Material Lift Permits	State	Cal/OSHA
	Hazardous Materials Business Plan	Local	Kern County Environmental Health Services Department
	California Accidental Release Prevention/Risk Management Plan	State/Federal	Kern County Environmental Health Services Department, USEPA
Land Use	Lot Line Adjustment	Local	Kern County Planning Department
	Williamson Act Cancellation	Local	Kern County Board of Supervisors
Soil and Water Resources	General Construction Activity Storm Water Permit, including the Notice of Intent and Storm Water Pollution Prevention Plan	State	SWRCB
	Low Threat Water Discharge Permit SWRCB 2003-0003-DWQ or CVRWQCB R5-2008-081	State or Regional	SWRCB or RWQCB Central Valley Region
	Septic System Design Review (part of Building Permit)	Local	Kern County Public Health Services Department, Environmental Health Division
	Encroachment permit for HDD under California Aqueduct	State	California Department of Water Resources

Resource Area	Permit/Approval	Local/State/ Federal	Agency
	Encroachment permit for HDD under Kern River Flood Control Channel	State	California Department of Water Resources
	Encroachment permit for crossing East and West Side Canals	Local	Buena Vista Water Storage District
	Building Permit	Local	Kern County Engineering, Surveying and Permit Services Department Building Inspection Division
	Grading Permit	Local	Kern County Engineering, Surveying and Permit Services Department Building Inspection Division
Traffic and Transportation	Determination of No Hazard to Navigable Airspace	Federal	Federal Aviation Administration
	State Highways Encroachment Permits	State	Caltrans
	State Highways Transportation Permit	State	Caltrans
	Encroachment Permit	Local	Kern County Roads Department Transportation and Encroachment Permits Division
	Transportation Permit	Local	Kern County Roads Department Transportation and Encroachment Permits Division
	Rail Spur Line public crossings	State	California Public Utilities Commission
	Encroachment Permit for HDD under the railroad right of way	Local	RailAmerica
Transmission	Final Interconnection Approval	State	California Independent System Operator

Resource Area	Permit/Approval	Local/State/ Federal	Agency
Waste Management	USEPA Hazardous Waste Generator Identification Number	Federal	California Environmental Protection Agency, Department of Toxic Substances Control
	Hazardous Waste Generator Program Permit	Local	County of Kern, Environmental Health Services Department

Notes:

Cal/OSHA = California Office of Safety and Health Administration
CDFW = California Department of Fish and Wildlife
CEC = California Energy Commission
CVRWQCB = Central Valley Regional Water Quality Control Board
DOE = Department of Energy
HDD = horizontal directional drilling
RWQCB = Regional Water Quality Control Board
SJVAPCD = San Joaquin Valley Air Pollution Control District
SWRCB = State Water Resources Control Board
USEPA = United States Environmental Protection Agency
USFWS = U.S. Fish and Wildlife Service

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U.S. DEPARTMENT OF ENERGY
Appendix 1
Environmental Synopsis CCPI Round 3

ENVIRONMENTAL SYNOPSIS
CCPI Round 3
DE-PS26-08NT43181
DE-FOA-0000042

October 2010

National Energy Technology Laboratory
U.S. Department of Energy
Morgantown, West Virginia

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CONTENTS

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INTRODUCTION

The U.S. Department of Energy (DOE or the Department) prepared this Environmental Synopsis pursuant to the Department's responsibilities under section 1021.216 of DOE's National Environmental Policy Act (NEPA) Implementing Procedures set forth in 10 CFR Part 1021. This synopsis summarizes the consideration given to environmental factors and records that the relevant environmental consequences of reasonable alternatives were evaluated in the process of selecting projects seeking financial assistance under Round 3 of the Clean Coal Power Initiative (CCPI). DOE selected five applicants seeking financial assistance under CCPI Round 3 during its merit review process. In addition to financial and technical elements, DOE considered relevant environmental factors and consequences of the projects proposed to DOE in response to the funding opportunity announcements. As required by section 1021.216, this synopsis does not contain business, confidential, trade secret or other information that statutes or regulations would prohibit DOE from disclosing. It also does not contain data or other information that may in any way reveal the identity of the offerors.[1]

BACKGROUND

Coal is an abundant and indigenous energy resource and supplies almost 50 percent of the United States' electric power. Demand for electricity is projected to increase by more than 30 percent by 2030. Based on analyses conducted by the EIA, it is projected that this power increase can only be achieved if coal use is also increased. Furthermore, nearly half of the nation's electric power generating infrastructure is more than 30 years old, with a significant portion in service for twice as long. These aging facilities are - or soon will be - in need of substantial refurbishment or replacement. Additional capacity must also be put in service to keep pace with the nation's ever-growing demand for electricity. Therefore, DOE expects that nearly half of the nation's electricity needs will continue to be served by coal for at least the next several decades. Given heightened awareness of environmental stewardship, while at the same time meeting the demand for a reliable and cost-effective electric power supply, it is clearly in the public interest for the nation's energy infrastructure to be upgraded with the latest and most advanced commercially viable technologies to achieve greater efficiencies, environmental performance, and cost-competitiveness. However, to realize acceptance and replication of these advanced technologies into the electric power generation sector, the technologies must first be demonstrated (i.e., designed and constructed to industrial standards and operated at significant scale under industrial conditions).

Public Law 107-63, enacted in November 2001, first provided funding for the Clean Coal Power Initiative, or CCPI. The CCPI is a multi-year federal program tasked with accelerating the commercial readiness of advanced multi-pollutant emissions control, combustion, gasification, and efficiency improvement technologies to retrofit or repower existing coal-based power plants and for deployment in new coal-based generating facilities. The CCPI encompasses a broad spectrum of commercial-scale demonstrations that target environmental challenges, including reducing greenhouse gas (GHG) emissions, by boosting the efficiency at which coal is converted to electricity or other energy forms. The CCPI is closely linked with DOE's research and development activities directed toward creating ultra-clean, fossil fuel-based energy complexes in the 21st century. When integrated with other DOE initiatives, the CCPI will help the nation successfully commercialize advanced power systems that will produce electricity at greater efficiencies, produce almost no emissions, and create clean fuels. Improving power plant efficiency is a potentially significant way to reduce carbon dioxide (CO_2) emissions in the near- and midterm. In the longer term, the most recent future funding opportunity announcements targeted CCPI technologies employing CO_2 capture and storage, or beneficial reuse. Accelerating

[1] The five projects selected for awards are identified in this synopsis and information on these projects is available on the DOE National Energy Technology Laboratory web site at http://www.netl.doe.gov/technologies/coalpower/cctc/ccpi/index.html.

commercialization of clean coal technologies also positions the United States to supply these technologies to a rapidly expanding world market.

Congress provided for competitively awarded federal cost-shared funding for CCPI demonstration projects. In contrast to other federally funded activities, CCPI projects are not federal projects seeking private investment; instead, they are private projects seeking federal financial assistance. Under the CCPI funding opportunities, industry proposes projects that meet its needs and those of its customers while furthering the national goals and objectives of DOE's CCPI. Demonstration projects selected by the CCPI program become private-public partnerships that satisfy a wide set of industry and government needs. Through the CCPI program, industry may satisfy its short-term need to retrofit or repower a facility, develop new power generating capacity, or obtain critical economic or technical evaluation of emerging commercial-scale technologies, all for the benefit of its customers. By providing financial incentives to the energy sector that reduce risks associated with project financing and technical challenges for emerging clean coal technologies, the government: (a) supports the verification of commercial readiness leading toward the long-term objective of transitioning the nation's existing fleet of electric power plants to more efficient, environmentally sound, and cost-competitive facilities; and (b) facilitates the adoption of technologies that can meet more stringent environmental regulation through more efficient power generation, advanced environmental controls, and production of environmentally attractive energy carriers and byproduct utilization.

DOE selects projects for CCPI funding in a series of rounds, each of which starts with a Funding Opportunity Announcement (FOA) that asks project proponents to submit applications for federal cost-sharing for their demonstration projects. DOE issued the first CCPI FOA (Round 1) in March 2002 and a second FOA (Round 2) in February 2004. These funding opportunities focused on projects involving advanced coal-based power generation, including gasification, efficiency improvements, optimization through neural networking, environmental and economic improvements, and mercury control. For Round 3, DOE issued a Financial Assistance FOA on August 11, 2008 (DE-PS26-08NT43181) to solicit applications and subsequently issued Amendment 005 (as DE-FOA-0000042) on June 9, 2009, to reopen the FOA and provide a second closing date (August 24, 2009) for additional applications. Projects receiving awards under the amended FOA could be funded, in whole or in part, with funds appropriated by the American Recovery and Reinvestment Act of 2009, Public Law 111-5.

Applications for demonstrations under CCPI Round 3 were evaluated against specific programmatic criteria:

• Technology merit, technical plan, and site suitability;

• Project organization and project management plan;

• Commercialization potential;

• Funding plan;

• Financial business plan.

Evaluations against these criteria represented the total evaluation scoring. However, the selection official also considered the results of the environmental evaluation and the applicant's budget information and financial management system, as well as program policy factors, in making final selections.

As a Federal agency, DOE must comply with NEPA (42 U.S.C. §§ 4321 et seq.) by considering potential environmental issues associated with its actions prior to deciding whether to undertake these actions. The environmental review of applications received in response to the CCPI Round 3 FOA was conducted pursuant to Council on Environmental Quality Regulations (40 Code of Federal Regulations (CFR) Parts 1500 - 1508) and DOE's NEPA Implementing Procedures (10 CFR Part 1021), which provide directions specific to procurement actions that DOE may undertake or fund before completing the NEPA process.

PURPOSE AND NEED

The purpose and need for DOE's selections of projects under the CCPI Program are to satisfy the responsibility Congress imposed on the Department to demonstrate advanced coal-based technologies that can generate clean, reliable, and affordable electricity in the United States.

The specific objectives of the Round 3 FOAs were:

- The CO_2 capture process must operate at a CO_2 capture efficiency of at least 90 percent;
- Progress is made toward carbon capture and sequestration (CCS) at less than a 10 percent increase in the cost of electricity for gasification systems and less than 35 percent increase for combustion and oxy-combustion systems;
- Progress is made toward CCS of 50 percent of plant CO_2 output at a scale sufficient to evaluate the full impact of the carbon capture technology on plant operations, economics, and performance; and
- At least 300,000 tons per year of CO_2 emissions from the demonstration plant must be captured and sequestered or put to beneficial use.

ALTERNATIVES

DOE received eleven (11) applications in response to the initial FOA (issued August 11, 2008) for CCPI-3, all of which were determined to have met the mandatory eligibility requirements listed in the FOA. The applications covered a wide geographic range, including sites in fourteen different states representing nearly every region of the country. In response to the reopened FOA (issued June 9, 2009), DOE received thirty eight (38) applications, of which twenty five (25)were determined to have met the mandatory eligibility requirements listed in the FOA. The requirements for the reopened FOA were the same as for the initial. The twenty five applications offered projects involving sites in nineteen different states representing nearly all geographic regions of the country. Several applicants in the initial FOA also resubmitted modified applications in response to the reopened FOA. The applications were evaluated against technical, financial and environmental factors. The criteria for evaluating applications received under CCPI-3 were published in the FOA. The technical and financial evaluations resulted in separate numerical scores; the environmental evaluation, while not scored, was considered in making selections. Each applicant was required to complete and submit a standard environmental questionnaire for each site proposed in its application.

The evaluations focused on the technical description of the proposed project, financial plans and budgets, potential environmental impacts, and other information that the applicants submitted. Following reviews by technical, environmental and financial panels and a comprehensive assessment by a merit review board, a DOE official selected those projects that best met the CCPI program's purpose and need. By broadly soliciting proposals to meet the programmatic purpose and need for DOE action and by evaluating the potential environmental impacts associated with each proposal before selecting projects, DOE considered a reasonable range of alternatives for meeting the purpose and need of the CCPI Round 3 solicitation.

For the initial FOA, applications were divided into three broad categories:

- Retrofit of CCS to an existing integrated gasification combined cycle (IGCC) facility or to an IGCC facility under construction;
- Retrofit of CCS to an existing pulverized coal (PC)-fired facility; and
- Construction and operation of new IGCC or Fluidized Bed Combustion (FBC) facilities with integrated CCS.

DOE received no less than two applications in each of the above groupings, which provided DOE with a range of reasonable alternatives for meetings the Department's need to demonstrate, at a commercial scale, new technologies that capture CO_2 emissions from coal-based power plants and either sequester the CO_2 or put it to beneficial reuse. The applications included demonstration of CCS integrated into new facilities using advanced technologies for power generation, as well as retrofits of CCS to existing facilities or ones already under construction, including both advanced and conventional technologies for power generation.

For the reopened FOA, DOE divided the applications into four groups, because of the larger number of submissions received:

- Retrofit of CCS to an existing plant (already permitted and operating);
- Retrofit of CCS to a planned or authorized power plant (but not yet constructed or operating);
- Construction and operation of a new power plant with CCS on an existing industrial site; and
- Construction and operation of a new power plant with CCS on an undeveloped site.

DOE received no less than four applications in each of the above groupings.

ENVIRONMENTAL REVIEW

DOE assembled environmental review teams to assess all applications that met the mandatory requirements. The review teams considered twenty (20) resource areas that could potentially be impacted by the projects proposed under CCPI-3. These resource areas consisted of:

Aesthetics	Floodplains	Soils
Air Quality	Geology	Surface Water
Biological Resources	Ground Water	Transportation and Traffic
Climate	Human Health and Safety	Utilities
Community Services	Land Use	Wastes and Materials
Cultural Resources	Noise	Wetlands
Environmental Justice	Socioeconomics	

The review teams were composed of environmental professionals with experience evaluating the impacts of power plants and energy-related projects, and with expertise in the resource areas considered by DOE. The review teams considered the information provided as part of each application, which included narrative text, worksheets, and the environmental questionnaire(s) for the site(s) proposed by the applicant. In addition, reviewers independently verified the information provided to the extent practicable using available sources commonly consulted in the preparation of NEPA documents, and conducted preliminary analyses to identify the potential range of impacts associated with each application. Reviewers identified both direct and indirect, as well as short-term impacts, which might occur during construction and start-up, and long-term impacts, which might occur over the expected operational life of the proposed project and beyond. The reviewers also considered any mitigation measures proposed by the applicant and any reasonably available mitigation measures that may not have been proposed.

Reviewers assessed the potential for environmental issues and impacts using the following characterizations:

- **Beneficial** – Expected to have a net beneficial effect on the resource in comparison to baseline conditions.

- **None (negligible)** – Immeasurable or negligible in consequence (not expected to change baseline conditions).
- **Low** – Measurable or noticeable but of minimal consequence (barely discernable change in baseline conditions).
- **Moderate** – Adverse and considerable in consequence but moderate and not expected to reach a level of significance (discernable, but not drastic, alteration of baseline conditions).
- **High** – Adverse and potentially significant in severity (anticipated substantial changes or effects on baseline conditions that might not be mitigable).

Applications in Response to the Initial FOA

Based on the technologies and sites proposed, none of the applications for the initial FOA were deemed to have a high potential for adverse impacts in nineteen of the twenty resource areas. However, four applications could have a potential for high adverse impacts to biological resources. The following impacts by resource area were considered in the selection of candidates for award:

Aesthetics – No impacts would be expected for one project at an existing power plant. Low to moderate impacts would be expected for other existing facilities or facilities to be constructed. Impacts ranged from temporary impacts during construction to new construction within the line-of-sight of public property, including nearby roads and highways.

Air Quality – Low to moderate impacts would be expected from emissions of criteria pollutants from new sources and fugitive emissions of dust. Compliance with Prevention of Significant Deterioration increments would be required for three projects; and new source reviews would be required for four projects. Increased emissions of volatile organic compounds (VOCs) and ammonia would be expected for more than half of the projects. Some increase in cooling tower drift could be expected for two projects.

Biological Resources – Four applications could potentially impact threatened or endangered species or their critical habitat, waterfowl and other migratory bird flyways or their crucial habitat, or wildlife refuges either because of new plant construction or installation of pipelines for CO_2 transport. No impacts were expected for two projects at existing plants. Low to moderate potential impacts would be expected for five applications.

Climate – No impacts would be expected for four projects at existing power plants. Low to moderate impacts would be expected for other existing facilities or facilities to be constructed. Impacts ranged from potential operational impacts from severe weather to localized increases in fogging or icing. Successful demonstration of CCS could contribute to reduced carbon footprints of fossil-fuel power plants.

Community Services – No impacts would be expected at the sites of two existing plants. Low to moderate impacts would be expected for the remaining applications. Generally, projects anticipating a larger temporary workforce during construction would be expected to place a higher demand on community services – particularly in smaller, more rural communities where currently existing community services are more limited.

Cultural Resources – No impacts would be expected at three existing facilities. Low to moderate impacts would be expected for the remaining applications. Potential impacts include tribal concerns over pipeline routes. Impacts would vary with the extent of known tribal claims and their proximity to the proposed project or pipeline route.

Environmental Justice – No impacts would be expected for five applications with no environmental justice populations present. There is a moderate potential for environmental justice issues at all but one of the remaining sites either because of environmental justice populations near the proposed site or along a proposed pipeline route. Potential impacts at the remaining site are expected to be low because of more limited environmental justice populations in the project area.

Floodplains – No impacts would be expected for two proposed projects. Low to moderate potential impacts during construction or pipeline routing would be expected for the remaining proposed projects.

Geology – The potential for low to moderate impacts exists for all applications either from CO_2 injection into saline aquifers or use for enhanced oil recovery. Some impacts could be expected from increased demand for coal if such demand contributes to opening new coal mines or expanding existing mines.

Ground Water – No impacts would be expected for one application involving an existing facility. Low to moderate impacts could be expected for the other applications. Impacts could include displacement of saline waters in reservoirs targeted for CO_2 injection or loss of CO_2 containment should injection pressures be too high.

Human Health and Safety – Potential impacts would be low to moderate and consist mainly of hazards associated with construction. The level of risk is generally related to the size and complexity of the planned construction. There could also be risk to human health and safety from loss of containment of CO_2 during transport and injection. This risk is present for all applications and generally varies from low to moderate with distance and population density along the CO_2 transport route where shorter routes through sparsely populated areas would have a lower risk than longer routes through regions of higher population.

Land Use – No impacts were identified for applications at existing facilities where the proposed project would not increase the footprint of the existing plant. Low to moderate impacts would be expected for applications proposing new construction. The level of potential impacts would generally be higher for new facilities on land currently used for other than industrial purposes. The assessment of impacts included both the plant site, sequestration site, and required pipeline routes for CO_2 transport.

Noise – No impacts would be expected for one project at an existing power plant. Low to moderate impacts could result from increases to ambient noise during construction and operation. Impacts would generally vary with distance and population density.

Socioeconomics – Expected impacts would be low for all applications. All applications would provide some additional employment during construction and operations. Most employment opportunities would be in the local area.

Soils – No impacts would be expected for one project at an existing power plant. Low impacts related to increased erosion during construction would be expected for other existing facilities requiring new pipelines or new facilities to be constructed.

Surface Water – Low to moderate impacts, including increased demand for cooling water and discharges to surface waters, would be expected for most of the applications. Some applications offered plans to maximize on-site reuse of water. Sediment control during construction was also considered.

Transportation and Traffic – Low to moderate impacts to traffic flow would be expected for all applications. Impacts would generally be higher during construction. Impacts expected during operations vary depending on increased rail or truck traffic. Projects in more rural areas would generally have lower impacts than new or existing facilities in more urban areas, where some increases in travel time could be expected during periods of peak construction.

Utilities – Low to moderate impacts would be expected for all applications. These would include an energy penalty for CCS retrofitted to existing power plants and increased demand for natural gas, potable water and wastewater treatment and disposal. Expected impacts would be higher for new plants proposed at sites not previously serviced by public utilities.

Wastes and Materials – Low to moderate impacts would be expected for all applications. Applications for projects that would include associated construction and operation of a new power plant would generally involve more material and waste impacts than would retrofits to existing plants.

Wetlands – No wetlands are located on the preferred site for one application. The potential for low to moderate impacts could be expected to small jurisdictional wetlands located on the proposed site or near proposed pipeline routes.

Applications in Response to the Reopened FOA

Based on the technologies and sites proposed, none of the applications for the reopened FOA were deemed to have a high potential for adverse impacts in sixteen of the twenty resource areas. All applications that would involve construction and operation of a new power plant were considered to have potentially high air quality impacts based on the need for new source permitting. Four applications were determined to have high potential for adverse impacts on biological resources; three applications were determined to have high potential for adverse impacts on surface waters; and one was determined to have high potential for adverse impacts on floodplains. The following impacts by resource area were considered in the selection of candidates for award:

Aesthetics – Impacts would be negligible for six projects that would involve retrofit or new construction at existing power plants or industrial sites. Low to moderate impacts would be expected for other retrofits to existing facilities or new facilities to be constructed. Moderate adverse impacts would result in the case of four applications involving construction of new power plants that would introduce line-of-sight impacts from superstructure and exhaust stacks where similar structures do not exist.

Air Quality – Impacts would result from emissions of criteria pollutants from new sources and fugitive emissions of dust. Twelve projects would have potentially high adverse impacts relating to emissions from proposed new plants. Lowest potential impacts would result from retrofits to existing or already-planned power plants.

Biological Resources – Four applications could potentially impact threatened or endangered species or their critical habitat, waterfowl and other migratory bird flyways, crucial habitat, or wildlife refuges either because of new plant construction or installation of pipelines for CO_2 transport. Moderate potential impacts would be expected for seven applications based on the locations of pipelines and other features. Low potential impacts would be expected for fourteen applications.

Climate – All applications were considered to present net beneficial effects on climate, because successful demonstration of CCS could contribute to reduced carbon footprints for fossil-fuel power plants. Potential adverse climate effects on plant operations were considered more from the perspective of engineering and design challenges to plant construction and maintenance.

Community Services – Negligible to low impacts would be expected for twenty applications. Five applications were determined to have potential for moderate impacts based on the size of the proposed projects to be located in smaller, more rural communities where existing community services are more limited.

Cultural Resources – Low potential for impacts would be expected for seventeen applications, including most retrofit projects. Moderate impacts would be expected for eight applications that could involve construction of structures or pipelines in proximity to tribal areas or historic sites.

Environmental Justice – Negligible to low potential for impacts would be expected for twenty three applications involving locations where environmental justice populations are not present. There is a moderate potential for environmental justice issues relating to the two remaining applications because of low-income or minority populations near the proposed site or along a proposed pipeline route.

Floodplains – One application would involve construction of structures within a 100-year floodplain with high potential for adverse impacts. Four applications were determined to have moderate potential impacts during construction of structures or pipelines. Negligible to low potential for impacts would be expected for twenty applications that do not directly involve actions in floodplains.

Geology – Negligible to low potential for impacts would be expected for twenty two applications based on CO_2 injection into saline aquifers or use for enhanced oil recovery. Three applications would have potential for moderate impacts based on limited information and uncertainties relating to target formations for proposed CO_2 injection.

Ground Water – Negligible to low potential for impacts would be expected for eighteen applications. Moderate impacts could be expected for the seven other applications relating to limited information about groundwater capacity to supply plant operations or the potential effects on groundwater sources from required dewatering operations.

Human Health and Safety – Moderate potential for impacts would be expected for seventeen applications; low potential would be expected for eight. The level of risk is generally related to the size and complexity of the planned construction. There could also be risk to human health and safety from loss of containment of CO_2 during transport and injection. This risk is present for all applications and generally varies from low to moderate with distance and population density along the CO_2 transport route.

Land Use – Negligible to low potential for impacts would be expected for twenty applications, mainly including projects involving retrofit at existing facilities or new construction on industrial sites. Moderate potential for impacts would be expected for five applications particularly requiring new construction on land currently used for other than industrial purposes.

Noise – Negligible to low potential for impacts from increases to ambient noise during construction and operation for all applications. Moderate potential for impacts could occur in the cases of five applications if coal would be transported by truck instead of by rail.

Socioeconomics – All applications were determined to provide beneficial impacts to the respective host areas based on economic multipliers associated with project spending as well as additional employment during construction and operations.

Soils – Low potential for impacts would be expected for twenty applications, mainly including projects involving retrofit at existing facilities or new construction on industrial sites. Moderate potential for impacts would relate to increased erosion during construction of structures or pipelines for five applications.

Surface Water – Three applications could have high potential for impacts attributable to substantial planned withdrawals from surface waters for plant operations, construction of pipelines along impaired surface waters, or planned discharges to surface waters. Moderate potential for impacts would be expected for eight applications; low potential would be expected for fourteen, including most retrofit projects.

Transportation and Traffic – Negligible to low potential for impacts could result from increases in traffic during construction and operation for all applications. Moderate potential for impacts could occur in the cases of five applications if coal would be transported by truck instead of by rail.

Utilities – Low potential for impacts would be expected for twelve applications that would not require extensive new pipelines and transmission lines. Thirteen applications would have potential for moderate impacts based on the need for longer pipeline and/or transmission line construction.

Wastes and Materials – Low potential for impacts would be expected for nine applications, including most projects proposing retrofits. Sixteen applications would have potential for moderate impacts based on the development of new facilities or new processes at existing facilities that would increase demands for management of materials and wastes.

Wetlands – The potential for negligible to low impacts could be expected for nineteen applications. Six applications would have potential for moderate impacts based on the lengths and routing of utility features and the potential for encountering wetlands along corridors.

CONCLUSION

The applications received in response to the CCPI-3 FOAs provided reasonable alternatives for accomplishing the Department's purpose and need to satisfy the responsibility Congress imposed on DOE to demonstrate advanced coal-based technologies that can generate clean, reliable and affordable electricity in the United States. The alternatives available to DOE would also meet the Department's goal of accelerating the deployment of carbon capture and storage. An environmental review was part of the evaluation process of these applications. DOE prepared a critique containing information from this environmental review. That critique, summarized here, contained summary as well as project-specific environmental information. The critique was made available to, and considered by, the selection official before selections for financial assistance were made.

DOE determined that selecting two applications in response to the initial FOA, and three applications in response to the reopened FOA, would meet its purpose and need. The following provides a list of the projects selected, their locations, brief descriptions of the projects, and the anticipated level of NEPA review:

CCPI-3 initial FOA:

- Hydrogen Energy California Project (Kern County, CA). Hydrogen Energy International LLC, a joint venture owned by BP Alternative Energy and Rio Tinto, would design, construct, and operate an IGCC power plant that would take blends of coal and petroleum coke, combined with non-potable water, and convert them into hydrogen and CO_2. The CO_2 would be separated from the hydrogen using the methanol-based Rectisol process. The hydrogen gas would be used to fuel a power station, and the CO_2 would be transported by pipeline to nearby oil reservoirs where it would be injected for storage and used for enhanced oil recovery. The project, which would be located in Kern County, California, would capture more than 2,000,000 tons per year of CO_2. The anticipated level of NEPA review for this project is an EIS.
- Basin Electric Power Cooperative - Post Combustion CO_2 Capture Project - Basin Electric Power Cooperative proposed to add CO_2 capture and sequestration (CCS) to Basin Electric's existing Antelope Valley Station, located near Beulah, N.D. Negotiations are still ongoing to define the project scope and schedule.

CCPI-3 reopened FOA:

- Mountaineer Carbon Dioxide Capture and Storage Demonstration (New Haven, WV). American Electric Power (AEP) would design, construct, and operate a chilled ammonia process that is expected to effectively capture at least 90 percent of the CO_2 (1.5 million metric tons per year) in a 235 megawatt (MW) flue gas stream at the existing 1,300 MW Appalachian Power Company (APCo) Mountaineer Power Plant near New Haven, WV. The captured CO_2 would be treated, compressed, and then transported by pipeline to proposed injection sites located near the capture facility. During the operation phase, AEP proposed to permanently store the entire amount of captured CO_2 in two separate saline formations located approximately 1.5 miles below the surface. The project team includes AEP, APCo, Schlumberger Carbon Services, Battelle Memorial Institute, CONSOL Energy, Alstom, and an advisory team of geologic experts. The anticipated level of NEPA review for this project is an EIS.
- The Texas Clean Energy Project. Summit Texas Clean Energy, LLC (Bainbridge Island, WA) would integrate Siemens gasification and power generating technology with carbon capture technologies to effectively capture 90% of the carbon dioxide (2.7 million metric tons per year) at a 400 MW plant to

be built near Midland-Odessa, TX. The captured CO_2 would be treated, compressed and then transported by CO_2 pipeline to oilfields in the Permian Basin of West Texas, for use in enhanced oil recovery (EOR) operations. The Bureau of Economic Geology (BEG) at the University of Texas would design and assure compliance with a state-of-the-art CO_2 sequestration monitoring, verification, and accounting program. The anticipated level of NEPA review for this project is an EIS.

- The Parish Post-Combustion CO_2 Capture and Sequestration Project (Thompsons, Texas). NRG Energy, Inc. (NRG) would design, construct, and operate a system that would capture and store approximately 400,000 tons of carbon CO_2 per year. The system would employ Fluor's Econamine FG Plus technology to capture at least 90 percent of the CO_2 from a 60 MW flue gas stream of the 617-MW Unit 7 at the W.A. Parish Generating Station located in Thompsons, Texas. Fluor's Econamine FG Plus CO_2 capture system features advanced process design and techniques, which lower the energy consumption of existing amine-based CO_2 capture processes by more than 20 percent. The captured CO_2 would be compressed and transported by pipeline to a mature oil field for injection into geologic formations for permanent storage through an enhanced oil recovery operation. The site would be monitored to track the migration of the CO_2 underground and to establish the permanence of sequestration. DOE is in the process of evaluating the appropriate level of NEPA documentation for this project.

COMPLIANCE CONDITIONS
INCLUDING THE COMPLIANCE MONITORING PLAN

Joseph Douglas

INTRODUCTION

The project's Compliance Conditions of Certification, including a Compliance Monitoring Plan (Compliance Plan), are established as required by Public Resources Code section 25532. The Compliance Plan provides a means for assuring that the facility is constructed, operated, and closed in compliance with public health and safety, environmental, all other applicable laws, ordinances, regulations, and standards (LORS), and the conditions adopted by the Energy Commission and specified in the written Decision on the Hydrogen Energy California, LLC (HECA), Application for Certification or otherwise required by law.

The Compliance Plan is composed of elements that:

- set forth the duties and responsibilities of the Compliance Project Manager (CPM), the project owner or operator (project owner), delegate agencies, and others;
- set forth the requirements for handling confidential records and maintaining the compliance record;
- state procedures for settling disputes and making post-certification changes;
- state the requirements for periodic compliance reports and other administrative procedures that are necessary to verify the compliance status for all Energy Commission approved conditions of certification;
- establish contingency planning, facility non-operation protocols, and closure requirements; and
- establish a tracking method for the technical area conditions of certification that contain measures required to mitigate potentially adverse project impacts associated with construction, operation, and closure below a level of significance; each technical condition of certification also includes one or more verification provisions that describe the means of assuring that the condition has been satisfied.

PROJECT CERTIFICATION

Project certification occurs on the day the Energy Commission dockets its Decision after adopting it at a publically noticed Business Meeting or hearing. At that time, all Energy Commission conditions of certification become binding on the project owner and the proposed facility.

KEY PROJECT EVENT DEFINITIONS

The following terms and definitions help determine when various conditions of certification are implemented.

Site Assessment and Pre-Construction Activities

Many of the Energy Commission's conditions of certification require compliance submittals and CPM approvals prior to the start of construction. The below-listed site assessment and pre-construction activities may be initiated or completed prior to the start of construction, subject to the CPM's approval of the specific site assessment or pre-construction activities.

Site assessment and pre-construction activities include the following, but only to the extent the activities are minimally disruptive to soil and vegetation and will not affect listed or special-status species or other sensitive resources:

1. the installation of environmental monitoring equipment;
2. a minimally invasive soil or geological investigation;
3. a topographical survey;
4. any other study or investigation to determine the environmental acceptability or feasibility of the use of the site for any particular facility; and
5. any minimally invasive work to provide safe access to the site for any of the purposes specified in 1-4, above.

Site Mobilization and Construction

When a condition of certification requires the project owner to take an action or obtain CPM approval prior to the start of construction, or within a period of time relative to the start of construction, that action must be taken, or approval obtained, prior to any site mobilization or construction activities, as defined below.

Site mobilization and construction activities are those necessary to provide site access for construction mobilization and facility installation, including both temporary and permanent equipment and structures, as determined by the CPM.

Site mobilization and construction activities include, but are not limited to:

1. ground disturbance activities like grading, boring, trenching, leveling, mechanical clearing, grubbing and scraping;
2. site preparation activities, such as access roads, temporary fencing, trailer and utility installation, construction equipment installation and storage, equipment and supply laydown areas, borrow and fill sites, temporary parking facilities, and chemical spraying and controlled burns; and
3. permanent installation activities for all facility and linear structures, including access roads, fencing, utilities, parking facilities, equipment storage, mitigation and landscaping activities, and other installations, as applicable.

Commissioning

Commissioning activities test the functionality of the installed components and systems to ensure the facility operates safely and reliably. Commissioning provides a multistage, integrated, and disciplined approach to testing, calibrating, and proving all of the project's systems, software, and networks. For compliance monitoring purposes, examples of commissioning activities include interface connection and utility pre-testing, “cold” and “hot” electrical testing, system pressurization and optimization tests, grid synchronization, and combustion turbine “first fire”.

Start of Commercial Operation

For compliance monitoring purposes, “commercial operation” or “operation” begins once commissioning activities are complete, the certificate of occupancy has been issued, and the power plant has reached reliable steady-state electrical production. At the start of commercial operation, plant control is usually transferred from the construction manager to the plant operations manager. Operation activities can include a steady state of electrical production, or, for “peaker plants,” a seasonal or on-demand operational regime to meet peak load demands.

Non-Operation and Closure

Non-operation is time-limited and can encompass part or all of a facility. Non-operation can be a planned event, usually for minor equipment maintenance or repair, or unplanned, usually the result of unanticipated events or emergencies.

Closure is a facility shutdown with no intent to restart operation. It may also be the cumulative result of unsuccessful efforts to re-start over an increasingly lengthy period of non-operation, condemned by inadequate means and/or lack of a viable plan. Facility closures can occur due to a variety of factors, including, but not limited to, irreparable damage and/or functional or economic obsolescence.

ROLES AND RESPONSIBILITIES

Provided below is a generalized description of the compliance roles and responsibilities for Energy Commission staff (staff) and the project owner for the construction and operation of the HECA project.

COMPLIANCE PROJECT MANAGER RESPONSIBILITIES

The CPM’s compliance monitoring and project oversight responsibilities include:

1. ensuring that the design, construction, operation, and closure of the project facilities are in compliance with the terms and conditions of the Decision;
2. resolving complaints;
3. processing post-certification project amendments for changes to the project description, conditions of certification, ownership or operational control, and requests for extension of the deadline for the start of construction (see **COM-10** for instructions on filing a Petition to Amend or to extend construction start date);
4. documenting and tracking compliance filings; and
5. ensuring that compliance files are maintained and accessible.

The CPM is the central contact person for the Energy Commission during project pre-construction, construction, emergency response, operation, and closure. The CPM will consult with the appropriate responsible parties when handling compliance issues, disputes, complaints, and amendments.

All project compliance submittals are submitted to the CPM for processing. Where a submittal requires CPM approval, the approval will involve appropriate Energy Commission technical staff and management. All submittals must include searchable electronic versions (.pdf, MS Word, or equivalent files).

Pre-Construction and Pre-Operation Compliance Meeting

The CPM usually schedules pre-construction and pre-operation compliance meetings prior to the projected start-dates of construction, plant operation, or both. These meetings are used to assist the Energy Commission and the project owner's technical staff in the status review of all required pre-construction or pre-operation conditions of certification, and take proper action if outstanding conditions remain. In addition, these meetings ensure, to the extent possible, that the Energy Commission's conditions of certification do not delay the construction and operation of the plant due to last-minute unforeseen issues or a compliance oversight. Pre-construction meetings held during the certification process must be publicly noticed unless they are confined to administrative issues and processes.

Energy Commission Record

The Energy Commission maintains the following documents and information as public records, in either the Compliance files or Dockets files, for the life of the project (or other period as specified):

1. all documents demonstrating compliance with any legal requirements relating to the construction and operation of the facility;
2. all Monthly and Annual Compliance Reports filed by the project owner;
3. all project-related complaints of alleged noncompliance filed with the Energy Commission; and
4. all petitions for project or condition of certification changes and the resulting staff or Energy Commission action.

CBO DELEGATION AND AGENCY COOPERATION

While monitoring project construction and operation, staff acts as, and has the authority of, the Chief Building Official (CBO), as required by CITE. Staff may delegate CBO responsibility to either an independent third-party contractor or a local building official. However, Staff retains CBO authority when selecting a delegate CBO, including the interpretation and enforcement of state and local codes, and the use of discretion, as necessary, in implementing the various codes and standards.

Energy Commission staff may also seek the cooperation of state, regional, and local agencies that have an interest in public and worker health and safety and environmental quality when conducting project monitoring.

PROJECT OWNER RESPONSIBILITIES

The project owner is responsible for ensuring that all conditions of certification in the HECA Decision are satisfied. The project owner will submit all compliance submittals to the CPM for processing unless the conditions specify another recipient. The compliance conditions regarding post-certification changes specify measures that the project owner must take when modifying the project's design, operation, or performance requirements, or to transfer ownership or operational control. Failure to comply with any of the conditions of certification may result in a correction order, an administrative fine, license revocation, or any combination thereof, as appropriate. A summary of the compliance conditions of certification are included as **Compliance Table 1** at the conclusion of this section.

COMPLIANCE ENFORCEMENT

The Energy Commission's legal authority to enforce the terms and conditions of its Decision are specified in Public Resources Code sections 25534 and 25900. The Energy Commission may amend or revoke a project certification and may impose a civil penalty for any significant failure to comply with the terms or conditions of the Decision. The Energy Commission's actions and fine assessments would take into account the specific circumstances of the incident(s).

PERIODIC COMPLIANCE REPORTING

Many of the conditions of certification require submittals in the Monthly and/or Annual Compliance Reports. All compliance submittals assist the CPM in tracking project activities and monitoring compliance with the terms and conditions of the HECA Decision. During construction, the project owner or an authorized agent will submit compliance reports on a monthly basis. During operation, compliance reports are submitted annually. These reports and the requirements for an accompanying compliance matrix are described below.

NONCOMPLIANCE COMPLAINT PROCEDURES

Any person or agency may file a complaint alleging noncompliance with the conditions of certification. Such a complaint will be subject to review by the Energy Commission pursuant to Title 20, California Code of Regulations, section 1237, but, in many instances, the issue(s) can be resolved by using an informal dispute resolution process. Both the informal and formal complaint procedures, as described in current state law and regulations, are summarized below. Energy Commission staff will follow these provisions unless superseded by future law or regulations. The California Office of Administrative Law provides on-line access to the California Code of Regulations at http://www.oal.ca.gov/.

Informal Dispute Resolution Process

The following informal procedure is designed to resolve code and compliance interpretation disputes stemming from the project's conditions of certifications and other LORS. The project owner, the Energy Commission, or any other party, including members of the public, may initiate the informal dispute resolution process. Disputes may pertain to actions or decisions made by any party, including the Energy Commission's delegate agents.

This process may precede the formal complaint and investigation procedure specified in Title 20, California Code of Regulations, section 1237, but is not intended to be a prerequisite or substitute for it. This informal procedure may not be used to change the terms and conditions of certification in the Decision, although the agreed-upon resolution may result in a project owner proposing an amendment. The informal dispute resolution process encourages all parties to openly discuss the conflict and reach a mutually agreeable solution. If a dispute cannot be resolved, then the matter must be brought before the full Energy Commission for consideration via the complaint and investigation procedure specified in Title 20, California Code of Regulations, section 1237.

Request for Informal Investigation

Any individual, group, or agency may request the CPM conduct an informal investigation of alleged noncompliance with the Energy Commission's conditions of certification. Upon receipt of an informal investigation request, the CPM will promptly provide both verbal and written notification to the project owner of the allegation(s), along with all known and relevant information of the alleged noncompliance. The CPM will evaluate the request and, if the CPM determines that further investigation is necessary, will ask the project owner to promptly conduct a formal inquiry into the matter and provide within seven days a written report of the investigation results, along with corrective measures proposed or undertaken. Depending on the urgency of the matter, the CPM may conduct a site visit and/or request that the project owner provide an initial verbal report within 48 hours.

Request for Informal Meeting

In the event that either the requesting party or Energy Commission staff are not satisfied with the project owner's investigative report or corrective measures, either party may submit a written request to the CPM for a meeting with the project owner. The request shall be made within 14 days of the project owner's filing of the required investigative report. Upon receipt of such a request, the CPM will attempt to:

1. immediately schedule a meeting with the requesting party and the project owner, to be held at a mutually convenient time and place;
2. secure the attendance of appropriate Energy Commission staff and staff of any other agencies with expertise in the subject area of concern, as necessary; and
3. conduct the meeting in an informal and objective manner so as to encourage the voluntary settlement of the dispute in a fair and equitable manner.

After the meeting, the CPM will promptly prepare and distribute copies to all parties, and to the project file, of a summary memorandum that fairly and accurately identifies the positions of all parties and any understandings reached. If no agreement was reached, the CPM will direct the complainant to the formal complaint process provided under Title 20, California Code of Regulations, section 1237.

Formal Dispute Resolution Procedure

Any person may file a complaint with the Energy Commission's Dockets Unit alleging noncompliance with a Commission Decision adopted pursuant to Public Resources Code section 25500. Requirements for complaint filings and a description of how complaints are processed are provided in Title 20, California Code of Regulations, section 1237.

POST-CERTIFICATION CHANGES TO THE ENERGY COMMISSION DECISION

The project owner must petition the Energy Commission pursuant to Title 20, California Code of Regulations, section 1769, to modify the design, operation, or performance requirements of the project and/or the linear facilities, or to transfer ownership or operational control of the facility. **It is the responsibility of the project owner to contact the CPM to determine if a proposed project change should be considered a project modification pursuant to section 1769.** Implementation of a project modification without first securing Energy Commission approval may result in an enforcement action including civil penalties in accordance with Public Resources Code, section 25534.

Below is a summary of the criteria for determining the type of approval process required, and reflects the provisions of Title 20, California Code of Regulations, section 1769, at the time this Compliance Plan was drafted. If the Energy Commission modifies this regulation, the language in effect at the time of the requested change shall apply. Upon request, the CPM can provide sample formats of these submittals.

Amendment

The project owner shall submit a Petition to Amend the Energy Commission Decision, pursuant to Title 20, California Code of Regulations, section 1769(a), when proposing modifications to the design, operation, or performance requirements of the project and/or the linear facilities. If a proposed modification results in an added, changed, or deleted condition of certification, or makes changes causing noncompliance with any applicable LORS, the petition will be processed as a formal amendment to the Decision, triggering public notification of the proposal, public review of the Energy Commission staff's analysis, and consideration of approval by the full Energy Commission.

Change of Ownership and/or Operational Control

Change of ownership or operational control also requires that the project owner file a petition pursuant to section 1769(b). This process requires public notice and approval by the full Commission. The petition shall be in the form of a legal brief and fulfill the requirements of section 1769(b).

Staff-Approved Project Modification

Modifications that do not result in additions, deletions, or changes to the conditions of certification, that are compliant with the applicable LORS, and that will not have significant environmental impacts, may be authorized by the CPM as a staff-approved project modification pursuant to section 1769(a)(2). Once the CPM files a Notice of Determination of the proposed project modifications, any person may file an objection to the CPM's determination within 14 days of service on the grounds that the modification does not meet the criteria of section 1769(a)(2). If there is a valid objection to the CPM's determination, the petition must be processed as a formal amendment to the Decision and must be considered for approval by the full Commission at a publically noticed Business Meeting or hearing.

Verification Change

Each condition of certification (except for the compliance conditions) has one or more means of verifying the project owner's compliance with the provisions of the condition. These verifications specify the actions and deadlines by which a project owner demonstrates compliance with the Energy Commission-adopted conditions. A verification may be modified by the CPM without requesting a Decision amendment if the change does not conflict with any condition of certification, does not violate any LORS, and provides an effective alternative means of verification.

CONTINGENCY PLANNING AND INCIDENT REPORTING

To protect public health and safety and environmental quality, the conditions of certification include contingency planning and incident reporting requirements to ensure compliance with necessary health and safety practices. A well-drafted contingency plan avoids or limits potential hazards and impacts resulting from serious incidents involving personal injury, hazardous spills, flood, fire, explosions or other catastrophic events and ensures a comprehensive timely response. All such incidents must be reported immediately to the CPM and documented. These requirements are designed to build from "lessons learned" limit the hazards and impacts, anticipate and prevent recurrence, and provide for the safe and secure shutdown and re-start of the facility.

FACILITY CLOSURE

The Energy Commission cannot reasonably foresee all potential circumstances in existence when a facility permanently closes. Therefore, the closure conditions provided herein must be flexible to address circumstances that may exist at some future time. Most importantly, facility closure must be consistent with all applicable Energy Commission conditions of certification and the LORS in effect at that time.

Although a non-operational facility may intend to resume operations, if it remains non-operational for longer than one year, unless the project owner can present a viable plan to resume operation, the Energy Commission can conclude that closure is imminent and direct the project owner to commence closure procedures. Should the project owner effectively abandon a facility, the Energy Commission can access the required financial assurance funds to begin closure, but the owner remains liable for all associated costs.

COMPLIANCE CONDITIONS OF CERTIFICATION

COM-1: UNRESTRICTED ACCESS

The project owner must take all steps necessary to ensure that the CPM, responsible Energy Commission staff, and delegated agencies or consultants have unrestricted access to the facility site, related facilities, project-related staff, and the records maintained on-site to facilitate audits, surveys, inspections, and general or closure-related site visits. Although the CPM will normally schedule site visits on dates and times agreeable to the project owner, the CPM reserves the right to make unannounced visits at any time, whether such visits are by the CPM in person or through representatives from Energy Commission staff, delegated agencies, or consultants.

COM-2: COMPLIANCE RECORD

The project owner must maintain electronic copies of all project files and submittals on-site, or at an alternative site approved by the CPM, for the operational life and closure of the project. The files shall also contain at least one hard copy of:

1. the facility's Applications for Certification;
2. all amendment petitions and Energy Commission orders;
3. all site-related environmental impact and survey documentation;
4. all appraisals, assessments, and studies for the project;
5. all finalized original and amended structural plans and "as-built" drawings for the entire project;
6. all citations, warnings, violations, or corrective actions applicable to the project, and
7. the most current versions of any plans, manuals and training documentation required by the conditions of certification or applicable LORS.

Energy Commission staff and delegate agencies must, upon request to the project owner, be given unrestricted access to the files maintained pursuant to this condition.

COM-3: COMPLIANCE VERIFICATION SUBMITTALS

Verification lead times associated with the start of construction may require the project owner to file submittals during the AFC process, particularly if construction is planned to commence shortly after certification. The verification procedures, unlike the conditions, may be modified as necessary by the CPM.

A cover letter from the project owner or an authorized agent is required for all compliance submittals and correspondence pertaining to compliance matters. **The cover letter subject line shall identify the project by AFC number, the appropriate condition(s) of certification number(s), and a brief description of the subject of the submittal**. When submitting supplementary or corrected information, the project owner shall reference the date of the previous submittal and the condition(s) of certification applicable. The project owner shall also identify those submittals **not** required by a condition of certification with a statement such as: "This submittal is for informational purposes only and is not required by a specific condition of certification."

All reports and plans required by the project's conditions of certification must be submitted in a searchable electronic format (.pdf, MS Word, or Excel, etc.) and include standard formatting elements such as a table of contents, identifying by title and page number, each section, table, graphic, exhibit, or addendum. All report and/or plan graphics and maps must be adequately scaled and must include a key with descriptive labels, directional headings, a bar scale, and the most recent revision date.

The project owner is responsible for the content and delivery of all verification submittals to the CPM, whether the actions required by the verification were satisfied by the project owner or an agent of the project owner. All submittals must be accompanied by an electronic copy on an electronic storage medium, or by e-mail, as agreed upon by the CPM. If hardcopy submittals are required, please address as follows:

Camille Remy Obad
HECA Compliance Project Manager
(08-AFC-8C)
California Energy Commission
1516 Ninth Street (MS-2000)
Sacramento, CA 95814

COM-4: PRE-CONSTRUCTION MATRIX AND TASKS PRIOR TO START OF CONSTRUCTION

Prior to start of construction, the project owner must submit to the CPM a compliance matrix including only those conditions that must be fulfilled before the start of construction. The matrix will be included with the project owner's first compliance submittal or prior to the first pre-construction meeting, whichever comes first, and will be submitted in a format similar to the description below.

Site mobilization and construction activities will not start until all of the following occur: submittal of the pre-construction matrix and compliance verifications pertaining to all pre-construction conditions of certification, and the CPM has issued an authorization to construct letter to the project owner. The deadlines for submitting various compliance verifications to the CPM allow sufficient staff time to review and comment on, and if necessary, allow the project owner to revise the submittal in a timely manner. These procedures help ensure that project construction proceeds according to schedule. Failure to submit required compliance documents by the specified deadlines may result in delayed authorizations to commence various stages of the project.

If the project owner anticipates site mobilization immediately following project certification, it may be necessary for the project owner to file compliance submittals prior to project certification. In these instances, compliance verifications can be submitted in advance of the required deadlines and the anticipated authorizations to start construction. The project owner must understand that submitting compliance verifications prior to these authorizations is at the owner's own risk. Any approval by Energy Commission staff prior to project certification is subject to change based upon the Commission Decision, and early staff compliance approvals do not imply that the Energy Commission will certify the project for actual construction and operation.

COM-5: COMPLIANCE MATRIX

The project owner must submit a compliance matrix to the CPM with each Monthly and Annual Compliance Report. The compliance matrix provides the CPM with the status of all conditions of certification in a spreadsheet format. The compliance matrix must identify:

1. the technical area (e.g., biological resources, facility design, etc.);
2. the condition number;

3. a brief description of the verification action or submittal required by the condition;
4. the date the submittal is required (e.g., sixty (60) days prior to construction, after final inspection, etc.);
5. the expected or actual submittal date;
6. the date a submittal or action was approved by the Chief Building Official (CBO), CPM, or delegate agency, if applicable;
7. the compliance status of each condition (e.g., “not started,” “in progress,” or “completed” (include the date); and
8. if the condition was amended, the updated language and the date the amendment was proposed or approved.

The CPM can provide a template for the compliance matrix upon request.

COM-6: MONTHLY COMPLIANCE REPORT/KEY EVENT LIST

The first Monthly Compliance Report is due one month following the docketing of the project’s Decision unless otherwise agreed to by the CPM. The first Monthly Compliance Report will include the AFC number and an initial list of dates for each of the events identified on the **Key Events List. The Key Events List form is found at the end of the Compliance Conditions section.**

During project pre-construction and construction the project owner or authorized agent will submit an electronic searchable version of the Monthly Compliance Report within ten (10) days after the end of each reporting month, unless otherwise specified by the CPM. Monthly Compliance Reports shall be clearly identified for the month being reported. The searchable electronic copy may be filed on an electronic storage medium or by e-mail, subject to CPM approval. The compliance verification submittal condition provides guidance on report production standards, and the Monthly Compliance Report will contain, at a minimum:

1. a summary of the current project construction status, a revised/updated schedule if there are significant delays, and an explanation of any significant changes to the schedule;
2. documents required by specific conditions to be submitted along with the Monthly Compliance Report; each of these items must be identified in the transmittal letter, as well as the conditions they satisfy, and submitted as attachments to the Monthly Compliance Report;
3. an initial, and thereafter updated, compliance matrix showing the status of all conditions of certification;
4. a list of conditions that have been satisfied during the reporting period, and a description or reference to the actions that satisfied the condition;
5. a list of any submittal deadlines that were missed, accompanied by an explanation and an estimate of when the information will be provided;
6. a cumulative listing of any approved changes to the conditions of certification;

7. a listing of any filings submitted to, or permits issued by, other governmental agencies during the month;
8. a projection of project compliance activities scheduled during the next two months; the project owner shall notify the CPM as soon as any changes are made to the project construction schedule that would affect compliance with conditions of certification;
9. a listing of the month's additions to the on-site compliance file; and
10. a listing of complaints, notices of violation, official warnings, and citations received during the month; a description of the actions taken to date to resolve the issues; and the status of any unresolved actions.

COM-7: ANNUAL COMPLIANCE REPORT

After construction is complete, the project owner must submit searchable electronic Annual Compliance Reports instead of Monthly Compliance Reports. The reports are for each year of commercial operation and are due each year on a date agreed to by the CPM. Annual Compliance Reports must be submitted over the life of the project, unless otherwise specified by the CPM. The searchable electronic copy may be filed on an electronic storage medium or by e-mail, subject to CPM approval. Each Annual Compliance Report must include the AFC number, identify the reporting period, and contain the following:

1. an updated compliance matrix showing the status of all conditions of certification (fully satisfied conditions do not need to be included in the matrix after they have been reported as completed);
2. a summary of the current project operating status and an explanation of any significant changes to facility operations during the year;
3. documents required by specific conditions to be submitted along with the Annual Compliance Report; each of these items must be identified in the transmittal letter with the condition it satisfies and submitted as an attachment to the Annual Compliance Report;
4. a cumulative listing of all post-certification changes approved by the Energy Commission or the CPM;
5. an explanation for any submittal deadlines that were missed, accompanied by an estimate of when the information will be provided;
6. a listing of filings submitted to, or permits issued by, other governmental agencies during the year;
7. a projection of project compliance activities scheduled during the next year;
8. a listing of the year's additions to the on-site compliance file;
9. an evaluation of the Site Contingency Plan, including amendments and plan updates; and
10. a listing of complaints, notices of violation, official warnings, and citations received during the year, a description of how the issues were resolved, and the status of any unresolved matters.

COM-8: CONFIDENTIAL INFORMATION

Any information that the project owner designates as confidential must be submitted to the Energy Commission's Executive Director with an application for confidentiality pursuant to Title 20, California Code of Regulations, section 2505 (a). Any information deemed confidential pursuant to the regulations will remain undisclosed as provided for in Title 20, California Code of Regulations, section 2501.

COM-9: ANNUAL ENERGY FACILITY COMPLIANCE FEE

Pursuant to the provisions of Section 25806(b) of the Public Resources Code, the project owner is required to pay an annually adjusted compliance fee. Current compliance fee information is available on the Energy Commission's website http://www.energy.ca.gov/siting/filing_fees.html. The project owner may also contact the CPM for the current fee information. The initial payment is due on the date the Energy Commission dockets its final Decision. All subsequent payments are due by July 1st of each year in which the facility retains its certification.

COM-10: AMENDMENTS, OWNERSHIP CHANGES, STAFF-APPROVED PROJECT MODIFICATIONS, AND VERIFICATION CHANGES

The project owner must petition the Energy Commission pursuant to Title 20, California Code of Regulations, section 1769, to modify the design, operation, or performance requirements of the project or linear facilities, or to transfer ownership or operational control of the facility. The CPM will determine whether staff approval will be sufficient or whether Commission approval will be necessary based upon whether or not the proposed amendment(s) result in a changed, added, or deleted condition of certification or the changes cause noncompliance with any applicable LORS. **It is the project owner's responsibility to contact the CPM to determine if a proposed project change triggers the requirements of section 1769.** Section 1769 details the required contents for a Petition to Amend an Energy Commission Decision. The only change that can be requested by means of a letter to the CPM is a request to change the verification method of a condition of certification.

Implementation of a project modification without first securing Energy Commission, or Energy Commission staff approval, may result in an enforcement action including civil penalties in accordance with section 25534 of the Public Resources Code. If the Energy Commission's rules regarding amendments are revised, the rules in effect at the time the change is requested shall apply.

COM-11: REPORTING OF COMPLAINTS, NOTICES, AND CITATIONS

Prior to the start of construction, the project owner must send a letter to property owners within one (1) mile of the project, notifying them of a telephone number to contact project representatives with questions, complaints, or concerns. If the telephone is not staffed twenty-four (24) hours per day, it must include automatic answering with a date and time stamp recording.

The project owner will respond to all recorded complaints within twenty-four (24) hours. The project site will post the telephone number on-site and make it easily visible to passersby during construction and operation. The project owner will provide the contact information to the CPM who will post it on the Energy Commission's web page at http://www.energy.ca.gov/sitingcases/hydrogen_energy/. The project owner must report any disruption to the contact system or telephone number change to the CPM promptly, to allow the CPM to update the Energy Commission's facility webpage accordingly.

In addition to including all complaints, notices and citations included with the Monthly and Annual Compliance Reports, within ten (10) days of receipt, the project owner must report, and provide copies to the CPM, of all complaints, including noise and lighting complaints, notices of violation, notices of fines, official warnings, and citations. Complaints must be logged and numbered. Noise complaints must be recorded on the form provided in the **Noise and Vibration** conditions of certification. All other complaints shall be recorded on the complaint form (Attachment A) at the end of the Compliance Plan.

COM-12: SITE CONTINGENCY PLAN

No less than sixty (60) days prior to the start of commercial operation, (or other date agreed to by the CPM) the project owner must submit for CPM review and approval, a Site Contingency Plan (Contingency Plan). The Contingency Plan must evidence a facility's coordinated emergency response and recovery preparedness for a series of reasonably foreseeable emergency events. The CPM may require updating of the Contingency Plan over the life of the facility. Contingency Plan elements include, but are not limited to:

1. a site-specific list and direct contact information for persons, agencies, and responders to be notified for an unanticipated event;
2. a detailed and labeled facility map, including all fences and gates, the windsock location (if applicable), the on- and off-site assembly areas, and the main roads and highways near the site;
3. a detailed and labeled map of population centers, sensitive receptors, and the nearest emergency response facilities;
4. a description of the on-site, first response and backup emergency alert and communication systems, site-specific emergency response protocols, and procedures for maintaining the facility's contingency response capabilities, including a detailed map of interior and exterior evacuations route, and the planned location(s) of all permanent safety equipment;
5. an organizational chart including the name, contact information, and first aid/emergency response certification(s) and renewal date(s) for all personnel regularly on-site;
6. a brief description of reasonably foreseeable site-specific incidents and accident sequences (on- and off-site), including response procedures and protocols and site security measures to maintain twenty-four hour site security;
7. procedures for maintaining contingency response capabilities; and
8. the procedures and implementation sequence for the safe and secure shutdown of all non-critical equipment and removal of hazardous materials and waste (see also specific conditions of certification for the technical areas of **Hazardous Materials Management** and **Waste Management**).

COM-13: INCIDENT REPORTING REQUIREMENTS

Within one (1) hour, the project owner must notify the CPM or COM, by telephone and e-mail, of any incident at the power plant or appurtenant facilities that results or could result in any of the following:

1. reduction in the facility's ability to respond to dispatch (excluding forced outages caused by protective equipment or other typically encountered shutdown events);
2. health and safety impacts on the surrounding population;
3. property damage off-site;
4. response by off-site emergency response agencies;
5. serious on-site injury;
6. serious environmental damage; or
7. emergency reporting to any federal, state, or local agency.

The notice must describe the circumstances, status, and expected duration of the incident. If warranted, as soon as it is safe and feasible, the project owner must implement the safe shutdown of any non-critical equipment and removal of any hazardous materials and waste that pose a threat to public health and safety and to environmental quality (also, see specific conditions of certification for the technical areas of **Hazardous Materials Management** and **Waste Management**).

Within one (1) week of the incident, the project owner must submit to the CPM a detailed incident report, which includes, as appropriate, the following information:

1. a brief description of the incident, including its date, time, and location;
2. a description of cause of the incident, or likely causes if it is still under investigation;
3. the location of any off-site impacts;
4. description of any resultant impacts;
5. a description of emergency response actions associated with the incident;
6. identification of responding agencies;
7. identification of emergency notifications made to other federal, state, and/or local agencies;
8. identification of any hazardous materials released and an estimate of the quantity released;
9. a description of any injuries, fatalities, or property damage that occurred as a result of the incident;
10. fines or violations assessed or being processed by other agencies;

    name, phone number, and e-mail address of the appropriate facility contact person having knowledge of the event; and

11. corrective actions to prevent a recurrence of the incident.

The project owner must maintain all incident report records for the life of the project, including closure. After the submittal of the initial report for any incident, the project owner shall submit to the CPM copies of incident reports within twenty-four (24) hours of a request.

COM-14: NON-OPERATION

If the facility ceases operation temporarily, either planned or unplanned, for longer than one (1) week (or other CPM-approved date), but less than three (3) months (or other CPM-approved date), the project owner must notify the CPM, interested agencies and nearby property owners. Notice of planned non-operation must be at least two (2) weeks prior to the scheduled date. Notice of unplanned non-operation must be provided no later than one (1) week after non-operation begins.

For any non-operation, a Repair/Restoration Plan for conducting the activities necessary to restore the facility to availability and reliable and/or improved performance shall be submitted to the CPM within one (1) week after notice of non-operation is given. If non-operation is due to an unplanned incident, temporary repairs and/or corrective actions may be undertaken before the Repair/Restoration Plan is submitted. The Repair/Restoration Plan shall include:

1. identification of operational and non-operational components of the plant;
2. a detailed description of the repair or restoration activities;
3. a proposed schedule for completing the repair or restoration activities;
4. an assessment of whether or not the proposed activities would require changing, adding, or deleting any conditions of certification or would cause noncompliance with any applicable LORS; and
5. planned activities during non-operation, including any measures to ensure continued compliance with all conditions of certification and LORS;.

Written updates to the CPM for non-operational periods, until operation resumes, shall include:

1. progress relative to the schedule;
2. developments that delayed or advanced progress or that may delay or advance future progress;
3. any public, agency or media comments or complaints; and
4. projected date for the resumption of operation.

During non-operation, all applicable conditions of certification and reporting requirements remain in effect. If, after one (1) year from the date of the project owner's last report of productive Repair/Restoration Plan work, the facility does not resume operation or does not provide a plan to resume operation, the Executive Director may assign suspended status to the facility and recommend commencement of permanent closure activities. Within ninety (90) days of the Executive Director's determination, the project owner shall do one of the following:

1. If the facility has a closure plan, the project owner shall update, submit for CPM approval, and initiate the closure activities in the approved plan.
2. If the facility does not have a closure plan, the project owner shall submit one consistent with the requirements in this Compliance Plan, for CPM review and approval.

COM-15: FACILITY CLOSURE PLANS

To ensure that a facility's closure and long-term maintenance do not pose a threat to public health and safety or to environmental quality, the project owner must coordinate with the Energy Commission to plan and prepare for eventual permanent closure.

A. Provisional Closure Plan and Estimate of Permanent Closure Costs

To assure satisfactory permanent closure and long-term site maintenance activities for "the whole of a project," the project owner must submit a Provisional Closure Plan and Cost Estimate (Provisional Plan), for CPM review and approval. The project owner must submit the Provisional Plan within sixty (60) days after the start of commercial operation. The Provisional Plan must consider applicable final closure plan requirements, including long-term, post-closure site maintenance costs, and reflect:

1. facility closure costs at a time in the facility's projected life span when the mode and scope of facility operation would make permanent closure the most expensive;
2. the use of an independent third party to carry out the permanent closure; and
3. no use of salvage value to offset closure costs.

A closure/decommissioning services consultant should prepare the Provisional Plan, and must provide for a phased closure process, including but not be limited to:

1. comprehensive scope of work and itemized budget;
2. closure plan development costs;
3. dismantling and demolition;
4. recycling and site clean-up;
5. mitigation and monitoring direct, indirect, and cumulative impacts;
6. site remediation and/or restoration;
7. post-closure monitoring and maintenance, including long-term equipment replacement costs; and
8. contingencies.

The project owner must include an updated Provisional Plan in every fifth-year Annual Compliance Report for CPM review and approval. Each Provisional Plan update must reflect the most current regulatory standards, best management practices, and applicable LORS.

B. Final Closure Plan

Three (3) years prior to initiating a permanent facility closure, the project owner must submit for CPM review and approval, a Final Closure Plan (Final Plan), which includes any long-term, post-closure site maintenance and monitoring. Final Plan contents include, but are not limited to:

1. a statement of specific Final Closure Plan objectives;
2. a statement of qualifications and resumes of the technical experts proposed to conduct the closure activities, with detailed descriptions of previous power plant closure experience;
3. identification of any facility-related installations not part of the Energy Commission license, designation of who is responsible for these, and an explanation of what will be done with them after closure;
4. a comprehensive scope of work and itemized budget for permanent plant closure and long-term site maintenance activities, with a description and explanation of methods to be used, broken down by phases, including, but not limited to:
    a. dismantling and demolition;
    b. recycling and site clean-up;
    c. impact mitigation and monitoring;
    d. site remediation and/or restoration;
    e. post-closure maintenance; and
    f. contingencies.
5. a revised/updated Cost Estimate for all closure activities, by phases, including long-term, post-closure site monitoring and maintenance costs, and replacement of long-term post-closure equipments;
6. a schedule projecting all phases of closure activities for the power plant site and all apurtenances constructed as part of the Energy Commission-licensed project;
7. an electronic submittal package of all relevant plans, drawings, risk assessments, and maintenance schedules and/or reports, including an above- and below-ground infrastructure inventory map and registered engineer's or delegate CBO's assessment of demolishing the facility; additionally, for any facility that permanently ceased operation prior to submitting a Final Closure Plan and for which only minimal or no maintenance has been done since, a comprehensive condition report focused on identifying potential hazards;
8. all information additionally required by the facility's conditions of certification applicable to plant closure;
9. an equipment disposition plan, including:
    a. recycling and disposal methods for equipment and materials; and
    b. identification and justification for any equipment and materials that will remain on-site after closure;

10. a site disposition plan, including but not limited to:
    a. proposed rehabilitation, restoration, and/or remediation procedures, as required by the conditions of certification and applicable LORS,
    b. long-term site maintenance activities, and
    c. anticipated future land-use options after closure;
11. identification and assessment of all potential direct, indirect, and cumulative impacts and proposal of mitigation measures to reduce significant adverse impacts to a less-than-significant level; potential impacts to be considered shall include, but not be limited to:
    a. traffic
    b. noise and vibration
    c. soil erosion
    d. air quality degradation
    e. solid waste
    f. hazardous materials
    g. waste water discharges
    h. contaminated soil
12. identification of all current conditions of certification, LORS, federal, state, regional and local planning efforts applicable to the facility, and proposed strategies for achieving and maintaining compliance during closure;
13. updated mailing list or listserv of all responsible agencies, potentially interested parties, and property owners within one (1) mile of the facility;
14. identification of alternatives to plant closure and assessment of the feasibility and environmental impacts of these; and
15. description of and schedule for security measures and safe shutdown of all non-critical equipment and removal of hazardous materials and waste (see conditions of certification for **Hazardous Materials Management** and **Waste Management**).

If a CPM-approved Final Closure Plan is not implemented within one (1) year of its approval date, it must be updated and re-submitted to the CPM for supplementary review and approval. If a project owner initiates but then suspends closure activities, and the suspension continues for longer than one (1) year, or subsequently abandons the facility, the Energy Commission may access the required financial assurance funds to complete the closure. The project owner remains liable for all costs of contingency planning and closure.

COM-16: FINANCIAL ASSURANCE FOR CLOSURE AND POST CLOSURE CARE

The project owner must provide financial assurances guaranteeing adequate and readily available funds to ensure facility closure and post-closure compliance. Within thirty (30) days following Provisional or Final Plan and Cost Estimate approval (whichever is most recent), the project owner must submit, for CPM review and approval, a financial assurance mechanism, such as a closure trust fund or surety bond, for no less than the amount provided in the approved Plan and Cost Estimate.

Provisions from the California Bond and Undertaking Law, as well as other statutory and case law may be applicable, consult an attorney if needed. Upon request, the CPM can provide examples of acceptable cost estimation techniques and financial assurance mechanisms.

Key Events List

PROJECT: ______________________________

DOCKET #: ______________________________

COMPLIANCE PROJECT MANAGER: ______________________________

EVENT DESCRIPTION	DATE
Certification Date	
Obtain Site Control	
On-line Date	
POWER PLANT SITE ACTIVITIES	
Start Site Assessment/Pre-construction	
Start Site Mobilization/Construction	
Begin Pouring Major Foundation Concrete	
Begin Installation of Major Equipment	
Completion of Installation of Major Equipment	
First Combustion of Gas Turbine	
Obtain Building Occupation Permit	
Start Commercial Operation	
Complete All Construction	
TRANSMISSION LINE ACTIVITIES	
Start T/L Construction	
Synchronization with Grid and Interconnection	
Complete T/L Construction	
FUEL SUPPLY LINE ACTIVITIES	
Start Gas Pipeline Construction and Interconnection	
Complete Gas Pipeline Construction	
WATER SUPPLY LINE ACTIVITIES	
Start Water Supply Line Construction	
Complete Water Supply Line Construction	

Compliance Table1
Summary of Compliance Conditions of Certification

CONDITION NUMBER	SUBJECT	DESCRIPTION
COM-1	Unrestricted Access	The project owner shall grant Energy Commission staff and delegate agencies or consultants unrestricted access to the power plant site.
COM-2	Compliance Record	The project owner shall maintain project files on-site. Energy Commission staff and delegate agencies shall be given unrestricted access to the files.
COM-3	Compliance Verification Submittals	The project owner is responsible for the delivery and content of all verification submittals to the CPM, whether such condition was satisfied by work performed or the project owner or his agent.
COM-4	Pre-construction Matrix and Tasks Prior to Start of Construction	Construction shall not commence until the all of the following activities/submittals have been completed: • Notify property owners • Submit pre-construction matrix identifying conditions to be fulfilled before the start of construction • Completed all pre-construction conditions • CPM has issued a letter to the project owner authorizing construction
COM-5	Compliance Matrix	The project owner shall submit a compliance matrix (in a spreadsheet format) with each monthly and Annual Compliance Report, which includes the status of all compliance conditions of certification.
COM-6	Monthly Compliance Report and Key Events List	During construction, the project owner shall submit Monthly Compliance Reports (MCRs) which include specific information. The first MCR is due the month following the Energy Commission business meeting date on which the project was approved and shall include an initial list of dates for each of the events identified on the Key Events List.
COM-7	Annual Compliance Reports	After construction ends and throughout the life of the project, the project owner shall submit Annual Compliance Reports instead of Monthly Compliance Reports.
COM-8	Confidential Information	Any information the project owner deems confidential shall be submitted to the Energy Commission's Executive Director with a request for confidentiality.
COM-9	Annual fees	Payment of the Annual Energy Facility Compliance Fee.
COM-10	Amendments, Ownership Changes, Staff-Approved Project Modifications, and Verification Changes	The project owner must petition the Energy Commission to delete or change a condition of certification, modify the project design or operational requirements and/or transfer ownership or operational control of the facility.

Compliance Table1
Summary of Compliance Conditions of Certification

CONDITION NUMBER	SUBJECT	DESCRIPTION
COM-11	Reporting of Complaints, Notices, and Citations	Prior to the start of construction, the project owner must provide all property owners within a one (1) mile radius a telephone number to contact project representatives with questions, complaints or concerns. Within ten (10) days of receipt, the project owner shall report to the CPM all notices, complaints, violations, and citations.
COM-12	Site Contingency Plan	No less than sixty (60) days prior to the start of commercial operation the project owner must submit an on-site contingency plan to ensure public and environmental health and safety are protected while responding to an unanticipated event or emergency.
COM-13	Incident Reporting Requirements	The project owner shall notify the CPM within one (1) hour of an incident and submit a detailed incident report within thirty (thirty) days, maintain records of incident report, and submit public health and safety documents with employee training provisions.
COM-14	Non-Operation	No later than two (2) weeks prior to a facility's planned non-operation, or no later than two (2) weeks after the start of unplanned non-operation, the project owner must notify the CPM, interested agencies and nearby property owners of this status. During non-operation, the project owner must provide written updates.
COM-15	Facility Closure Plans	One (1) year after initiating commercial operation, the project owner must submit a Provisional Closure Plan and Cost Estimate for permanent closure. Three (3) years prior to closing, the project owner must submit a Final Closure Plan.
COM-16	Financial Assurance for Closure	Within 120 days of initiating commercial operation, the project owner must establish a CPM approved closure financial assurance mechanism to ensure the necessary funds to adequate perform a facility closure and provide post closure care, as necessary.

Attachment A
Complaint Report/Resolution Form

COMPLAINT LOG NUMBER:________________________ DOCKET NUMBER:________________________

PROJECT NAME:____

COMPLAINANT INFORMATION

NAME:____ PHONE NUMBER:____________________________

ADDRESS:____

COMPLAINT

DATE COMPLAINT RECEIVED:______________________ TIME COMPLAINT RECEIVED:__________________

COMPLAINT RECEIVED BY: ______________________ ☐ TELEPHONE ☐ IN WRITING (COPY ATTACHED)

DATE OF FIRST OCCURRENCE:______________________

DESCRIPTION OF COMPLAINT (INCLUDING DATES, FREQUENCY, AND DURATION):______________________

____

____

FINDINGS OF INVESTIGATION BY PLANT PERSONNEL:____

____

____

DOES COMPLAINT RELATE TO VIOLATION OF A CEC REQUIREMENT? ☐ YES ☐ NO

DATE COMPLAINANT CONTACTED TO DISCUSS FINDINGS:______________________________________

DESCRIPTION OF CORRECTIVE MEASURES TAKEN OR OTHER COMPLAINT RESOLUTION:__________________

____

____

DOES COMPLAINANT AGREE WITH PROPOSED RESOLUTION? ☐ YES ☐ NO

IF NOT, EXPLAIN:____

____

CORRECTIVE ACTION

IF CORRECTIVE ACTION NECESSARY, DATE COMPLETED:______________________________________

DATE FIRST LETTER SENT TO COMPLAINANT (COPY ATTACHED):_______________________________

DATE FINAL LETTER SENT TO COMPLAINANT (COPY ATTACHED):_______________________________

OTHER RELEVANT INFORMATION:____

____

____

"This information is certified to be correct."

PLANT MANAGER SIGNATURE:________________________________ DATE:______________________

HYDROGEN ENERGY CALIFORNIA (08-AFC-08A)
PRELIMINARY STAFF ASSESSMENT
DRAFT ENVIRONMENTAL IMPACT STATEMENT
PREPARATION TEAM

Executive Summary ....John Heiser

Introduction ....

Project Description..John Heiser

Environmental Assessment

Air Quality .... William Walters, P.E. / Nancy Fletcher

Biological Resources ....Amy Golden

Carbon Sequestration and Greenhouse Gas Emissions ....William Walters, PE / David Vidaver
Abdel-Karim Abulaban, Ph.D, PE / Tad Patzek, Ph.D

Cultural Resources ....Gabriel Roark, M.A. / Thomas Gates Ph.D.
Melissa Mourkas, M.A., ASLA / Elizabeth A. Bagwell, Ph.D

Hazardous Materials Management ....Alvin Greenberg, Ph.D.

Land Use...Jonathan Fong

Noise and Vibration...Edward Brady / Shahad Khoshmashrab

Public Health..Alvin Greenberg, Ph.D.

Socioeconomics...Lisa Worrall / Amanda Stennick

Soils and Surface Water .... Marylou Taylor, PE

Traffic and Transportation.. John Hope

Transmission Line Safety and Nuisance...Obed Odoemelam, Ph.D

Visual Resources .... Elliott Lum

Waste Management...Ellie Townsend-Hough

Water Supply ....Mike Conway, PG / John Fio / Steve Deverel, PG

Worker Safety and Fire Protection ....Alvin Greenberg, Ph.D.

Engineering Assessment

Facility Design... Shahab Khoshmashrab

Geology and Paleontology...Casey Weaver, C. E. G.

Power Plant Efficiency .... Edward Brady

Power Plant Reliability .... Edward Brady

Transmission System Engineering .... Sudath Edirisuriya / Mark Hesters

Alternatives ....Negar Vahidi / Scott Debauche

General Conditions .... Joseph Douglas

Project Assistant .... Diane L. Scott

HYDROGEN ENERGY CALIFORNIA (08-AFC-08A)
PRELIMINARY STAFF ASSESSMENT
DRAFT ENVIRONMENTAL IMPACT STATEMENT
DOE PREPARATION TEAM

Federal Project Manager..John Rockey

Environmental Manager / NEPA Compliance Officer.. Fred Pozzuto

Federal Project Engineer ....Anthony Zinn

Division Directors

Major Projects Division..Gary Stiegel

Environmental Compliance Division.. Cliff Whyte

Chief Counsel...R. Paul Detwiler