Preliminary Staff Assessment

EAST ALTAMONT ENERGY CENTER

Application For Certification (01-AFC-4)
Alameda County

CALIFORNIA ENERGY COMMISSION

STAFF REPORT

DECEMBER 2001
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EXECUTIVE SUMMARY

INTRODUCTION

This Preliminary Staff Assessment (PSA)/Preliminary Environmental Assessment (EA) contains the California Energy Commission and Western Area Power Administration (Western) staff's independent analyses and recommendations on the East Altamont Energy Center (EAEC).

The EAEC and related facilities such as the electric transmission lines, natural gas line, water supply lines and wastewater lines are under the Energy Commission's jurisdiction (Pub. Resources Code § 25500). When issuing a license, the Energy Commission acts as lead state agency (Pub. Resource Code § 25519(c)) under the California Environmental Quality Act (Pub. Resource Code §§ 21000 et seq.), and its process is functionally equivalent to the preparation of an environmental impact report (Cal. Code Regs., tit. 14 § 15251(k)).

It is the responsibility of the Energy Commission staff to complete an independent assessment of the project's potential effects on the environment, the public's health and safety, and determine whether the project conforms with all applicable laws, ordinances, regulations and standards (LORS). The staff also recommends measures to mitigate potential significant adverse environmental impacts and conditions for the construction, operation, and eventual closure of the project, if approved by the Energy Commission.

The project is also under the jurisdiction of Western, as the power plant will interconnect with Western's transmission system. Western is a Federal power marketing agency under the U.S. Department of Energy that operates and maintains about 800 miles of high-voltage transmission lines and associated facilities in Northern California, including the Tracy Substation. Western's mission is to market power from federal hydroelectric plants such as those at Shasta and Folsom dams.

Federal law requires Western to provide entities, such as merchant power plants, open access to transmission services so that they can move power to load areas. Western provides these services through an interconnection if there is available capacity on the transmission line. Western is the lead federal agency for the project.

To streamline the process and eliminate overlap and duplication between the state and federal processes, this joint Energy Commission/Western PSA/Preliminary EA contains the evaluation of the project by the staffs of the California Energy Commission and Western. This document will be the basis for the decisions of both the Energy Commission and Western. This analysis includes both the construction and operation of the proposed facility. The analyses contained in this PSA/Preliminary EA were prepared in accordance with PRC Sections 25500 *et seq*.; the California Code of Regulations (CCR) Title 20, Sections 12001 *et seq*.; the California Environmental Quality Act (PRC §§ 21000 *et seq*.) and its guidelines (CCR title 14 §§ 15000 *et seq.*); the National Environmental Policy Act (NEPA) (42 U.S.C. 4371 *et seq*.) and its implementing regulations (40 C.F.R. §§ 1500 *et seq*.); and the Department of Energy NEPA Implementing Procedures and Guidelines (10 C.F.R. 1021).

This PSA is not the decision document for these proceedings. It is preliminary in nature and represents preliminary conclusions at the staff level only. With respect to the California Energy Commission's process, it is also important to note that the final decision will be made by the Commissioners of the California Energy Commission only after the completion of the Final Staff Assessment (FSA) and evidentiary hearings. The Commissioners will consider the recommendations of all interested parties, including those of the Energy Commission staff; the applicant; intervenors; concerned citizens; and local, state, and federal agencies, before making a final decision on the application to construct and operate the EAEC.

For Western, this preliminary document serves an additional purpose. The Preliminary EA allows Western to analyze and judge the magnitude of environmental impacts and provides interested stakeholders, agencies and tribes an opportunity to review the document. If Western finds that there are no significant environmental impacts, it will issue an EA along with the California Energy Commission's FSA, and will then issue a "finding of no significant impacts" and move forward with the project. If Western determines that significant impacts are a possibility it will prepare a draft environmental impact statement instead of an EA, which entails taking a more detailed look at the impacts and alternative approaches to the project. If an EIS is needed, Western will independently publish a final environmental impact statement and Record of Decision.

PROJECT LOCATION AND DESCRIPTION

On March 29, 2001, East Altamont Energy Center, LLC, a wholly owned subsidiary of Calpine Corporation, filed an AFC with the Energy Commission for a nominal 1,100 MW power plant called the East Altamont Energy Center (EAEC). East Altamont Energy Center, LLC (applicant) proposes to construct and operate a natural-gas-fired combined-cycle generating facility with a 230-kilovolt (kV) switchyard and approximately 0.5 miles of new 230-kW transmission lines. The applicant's proposed site lies within a 174-acre parcel of land under the applicant's control, located in unincorporated Alameda County, approximately 1 mile west of the San Joaquin County line and 1 mile southeast of the Contra Costa County line. The site is bordered by Byron Bethany Road to the north, Kelso Road to the south, and Mountain House Road to the west. If built, the plant would occupy up to 40 acres near the center of the property, with the remainder available for lease as agricultural land. **PROJECT DESCRIPTION Figure 1** depicts the regional setting of the property.

The switchyard would function as an extension of Western's existing Tracy substation, located across Mountain House Road and immediately to the west of the project's site. Natural gas for the facility would be delivered via approximately 1.4 miles of new 20-inch pipeline that will connect to Pacific Gas and Electric's (PG&E) existing gas transmission line southeast of the Bethany gas compressor station located to the west of the site.

The applicant plans to supply the plant's cooling and process water requirements (roughly 4,600 acre-feet per year) with raw (i.e. untreated) water from the Byron Bethany Irrigation District, via a 2.1-mile pipeline. The applicant also indicated in their AFC that, as the community of Mountain House is developed and recycled water

becomes available, the Byron Bethany Irrigation District (BBID) would be able to serve the facility in part with recycled water, resulting in a reduction in raw water use. However, because significant amounts of recycled water would not be available for at least 20 years, this identified alternative source of cooling water is considered too speculative for the purposes of the Energy Commission's analysis of the AFC. Therefore, staff's analysis assumes that the plant would rely solely on raw water.

The project as proposed includes a zero-liquid discharge system designed to eliminate off-site disposal of wastewater. Process wastewater would be reclaimed and reused, to the extent possible. Cooling water would be cycled three to eight times (depending on water quality) in the cooling tower; wastewater would then be directed to a brine crystallizer. Sanitary wastewater from sinks and toilets would be discharged to an onsite septic tank and leach field.

Associated equipment would include emission control systems necessary to meet the proposed emission limits. NOx emissions will be controlled using a combination of low NOx combustors in the combustion turbine generators (CTGs) and selective catalytic reduction systems in the heat recovery steam generators (HRSGs). A carbon monoxide catalyst would be installed in the HRSGs to limit CO emissions from the CTGs.

The project is estimated to have a capital cost of between $400 and $500 million. The applicant plans to begin construction in June 2002 and complete construction in June 2004. The project would result in a peak of approximately 400 construction jobs over a 2-year period and up to 40 skilled operational positions throughout the life of the project.

PUBLIC AND AGENCY COORDINATION

In preparing the PSA, Energy Commission and Western staff conducted several publicly noticed joint workshops. These workshops were invaluable for bringing out comments of concerned citizens. Staff also has coordinated with relevant local, state and federal agencies, such as the California Independent System Operator (Cal-ISO), Bay Area Air Quality Management District, U.S. Fish and Wildlife Service, California Department of Fish and Game, and the Central Valley Regional Water Quality Control Board.

Written comments received from members of the public, and letters from agencies that require some form of response, have been included in this PSA. No comments have been received from intervenors.

STAFF'S ASSESSMENT

Each technical area section of the PSA contains a discussion of impacts, and where appropriate, mitigation measures and conditions of certification. The PSA includes staff's assessments of:

- the environmental setting of the proposal;
- impacts on public health and safety, and measures proposed to mitigate these impacts;

- environmental impacts, and measures proposed to mitigate these impacts;
- the engineering design of the proposed facility, and engineering measures proposed to ensure the project can be constructed and operated safely and reliably;
- project closure;
- project alternatives;
- compliance of the project with all applicable laws, ordinances, regulations and standards (LORS) during construction and operation; and
- proposed conditions of certification.

OVERVIEW OF STAFF'S CONCLUSIONS

Environmental / System Impacts and LORS

Staff's analysis indicates that the project's environmental impacts can be mitigated to levels of less than significant in all areas except for Air Quality, Biological Resources, Land Use, Visual Resources, Soil and Water Resources, and Transmission System Engineering. Staff's analysis also indicates that the project can be made to conform with all LORS except in the areas of Air Quality, Land Use, Soil and Water Resources, and Transmission System Engineering. Below is a summary of the potential environmental impacts and LORS compliance for each technical area.

Technical Discipline	Environmental / System Impact	LORS Conformance
Air Quality	Staff cannot conclude	Staff cannot conclude
Biological Resources	Staff cannot conclude	yes
Cultural Resources	Impacts mitigated	yes
Power Plant Efficiency	N/A	N/A
Power Plant Reliability	N/A	N/A
Facility Design	N/A	yes
Geology	Impacts mitigated	yes
Hazardous Materials	Impacts mitigated	yes
Land Use	Staff cannot conclude	Staff cannot conclude
Noise	Impacts mitigated	yes
Public Health	Impacts mitigated	yes
Socioeconomics	Impacts mitigated	yes
Traffic and Transportation	Impacts mitigated	yes
Transmission Line Safety	Impacts mitigated	yes
Transmission System Engineering	Staff cannot conclude	Staff cannot conclude
Visual Resources	Staff cannot conclude	yes
Waste Management	Impacts mitigated	yes
Water and Soils	Staff cannot conclude	Staff cannot conclude
Worker Safety	Impacts mitigated	Yes

The following summarizes staff's position with respect to the technical areas listed as "Staff cannot conclude":

Air Quality

There are still a number of significant, outstanding air quality issues that have the potential to delay the overall project schedule and have impacted staff's ability to draw conclusions in the PSA.

- First and foremost, the Bay Area Air Quality Control District has not issued its Preliminary Determination of Compliance for the project. Without the PDOC, staff cannot conclude that the project would be in conformance with local, state, and federal air quality laws.
- Still unresolved at this time is the matter of what Best Available Control Technology should apply to the EAEC. The applicant has proposed to use selective catalyst reduction (SCR) and oxidation catalysts to minimize the emissions of oxides of nitrogen (NOx) to 2.5 parts per million (ppm), and carbon monoxide (CO) to 6 ppm, while maintaining the slip of ammonia (NH3) emissions to 10 ppm. However, the Federal Environmental Protection Agency (EPA), recently determined that the BACT for a combustion turbine combined cycle operation should be set at 2 ppm for NOx, 2 ppm for CO and 5 ppm for ammonia. Staff is recommending that the project mitigate to the above-mentioned EPA-recommended BACT levels, but the EPA will not officially comment on this project until after the PDOC.
- Staff has found that the project's emissions of NO_x and VOC have the potential to cause significant impacts relative to the state 1-hour and the federal 8-hour ozone air quality standards. The area experiences violations of the state 1-hour and federal 8-hour ozone standards each year (since 1992) and there is no clear indication of improvement. Thus, it is crucial that any NO_x and VOC emission increases be fully offset to avoid worsening violations of the ozone ambient air quality standard. The applicant has not provided staff with enough information about the emission reduction credits (ERCs), and staff therefore cannot determine whether the applicant's proposed offset package is adequate to mitigate the project's emissions of NO_x and VOC to a level of less than significant.
- Staff has found that the project has the potential to cause significant impacts relative to the state 24-hour PM_{10} and the federal 24-hour $PM_{2.5}$ air quality standards. Staff finds that the proposed ERCs, however, are not adequate to mitigate the project's emissions of PM_{10} and $PM_{2.5}$. Staff understands that the applicant is in the process of changing their mitigation proposal, but until staff receives the revised proposal and evidence of ERCs, staff cannot draw any conclusions about the project's mitigation for PM_{10} and $PM_{2.5}$.
- Staff continues to disagree with the applicant over emission levels and mitigation for PM_{10}, NO_2, VOC, and SO_2, and the level of detail that must be provided to staff regarding key pieces of equipment. The applicant maintains that the design is not finalized, thus specific information about the duct burners (which are significantly larger than the duct burners seen in other California power plants), the boiler, and the emergency generator and fire pump are not available. Because emission data and physical characteristics of the equipment involved have not been provided, staff cannot verify the modeling analysis performed by the applicant, and lacks the information required to properly assess the project's impacts. Further, the applicant has not yet provided enough information for staff to evaluate the ERCs for this

project. Staff cannot complete its analysis until the applicant provides more information in these areas. Staff plans to issue new data requests that clarify the information that we require.

- Finally, staff has requested the applicant prepare a cumulative impacts analysis that includes the Tracy Peaker Project, the Tesla Power Project, and the build-out of the new community of Mountain House. Until this analysis is completed, staff cannot reach conclusions regarding cumulative impacts to air quality.

Visual Resources

It is staff's conclusion that the proposed power plant facility is inconsistent with the existing rural character of the area. It would be visible from recreational areas and would affect panoramic scenic views. The applicant's proposed visual resources mitigation measures and screening plan, and staff's proposed mitigation measures and conditions of certification would mitigate the visual impacts of the proposed project to less than significant levels. However, biology staff of the Energy Commission, California Department of Fish and Game (CDFG) and U.S. Fish and Wildlife Service (USFWS) are concerned about potential biological impacts of the proposed landscaping. To address this issue, the applicant has prepared a revised landscaping plan that staff will evaluate in the Final Staff Assessment. If the revised landscape plan would not result in full and timely implementation of staff's proposed landscaping mitigation, or if the mitigation is determined to not be feasible, significant visual impacts from the proposed project structures would remain.

Biological Resources

The following represent outstanding issues for Biological Resources:

- Staff is concerned about the timing of the Section 7 consultation process. The Biological Assessment has not been submitted by the applicant to Western, and thus the Section 7 consultation with the USFWS has not yet been initiated. Delays in the Section 7 consultation process could significantly affect the overall project schedule. Staff cannot draw conclusions about the project's potential for environmental impacts until it has the final Biological Opinion, or a draft of the Biological Opinion that provides reasonable assurance of the mitigation that will be included in the Biological Opinion.
- At present, the requirement that the applicant avoid adverse biological impacts from the proposed landscaping conflicts directly with mitigation required to minimize impacts to visual resources. Because the proposed landscaping would provide perching opportunities for raptors, and may harm federally listed species, biology staff, CDFG, and USFWS believe that the originally proposed landscaping is unacceptable. The most recent landscaping proposal continues to be reviewed and discussed among the agencies, the applicant, and staff. Staff needs to receive further information from the applicant on the habitat mitigation and will consult with USFWS and CDFG in order to ensure that the mitigation determined in the FSA is sufficient.
- The EAEC proposes to use fresh water for cooling. This water would be delivered by the BBID, which removes water from the California Aqueduct, and ultimately, the Sacramento-San Joaquin Delta (Delta). The Delta is critical habitat for many

declining or endangered fish species, and also supports fish of importance to sport fishermen.

- Staff is concerned with the levels of water to be withdrawn from the Delta due to the indirect and cumulative impacts this would have on native listed fish populations and their habitats. The National Marine Fisheries Service (NMFS) has expressed concern for the potential of indirect ecological impacts of water diversions from the Delta, which is designated as critical habitat for these fish species. The NMFS stated: "If diversions are not increased over current conditions, we would not anticipate adverse effects on listed salmon or steelhead, designated critical habitat or Essential Fish Habitat (EFH). *However, if diversions into the California Aqueduct are increased as a result of the construction and operation of the proposed project,* adverse effects on listed salmon or steelhead, designated critical habitat, and/or EFH may occur, and further consultation would be required." (emphasis added) (NMFS 2001).

  The EAEC will require approximately 4,600 acre-feet per year of water. While Byron Bethany Irrigation District (BBID) – the water purveyor for the EAEC – maintains that serving the EAEC with this water will not result in additional water diversions to the California Aquaduct, staff has no evidence of this. Such a level of water diversion from the Delta, if it occurred, would cause potentially significant adverse impacts to listed fish populations in the Delta. DWR as well has expressed concern that its beneficial uses under the SWP, or other Delta beneficial uses including maintenance of plantlife, fish and wildlife, could be injured. (CEC 2001i, page 1) Given that two other power plant applications being considered by the Energy Commission include proposals to withdraw freshwater from the Delta (i.e. the Tracy Peaker Plant and Tesla Power Plant), impacts to fish populations could be compounded and the combined water withdrawals could cause significant adverse cumulative impacts.

  The question of whether or not the proposed supply of water for the EAEC would result in increased diversions from the Delta must be resolved before a final assessment of project impacts can be completed. As noted in the **Soil and Water Resources** section of this Staff Assessment, staff is awaiting additional information from DWR and the Applicant relative to previous Bay-Delta analyses and the relationship of BBID's water entitlements to those of the SWP and CVP. If staff determines that there could be increased diversions from the Delta, the applicant will need to consult a second time with NMFS. Until information received either confirms that there would be no net withdrawals from the Delta, or a second consultation with NMFS is completed, staff cannot conclude that there are less than significant impacts to native special status fish populations. If staff cannot confirm that there are no net withdrawals from the Delta, staff will additionally need to evaluate cumulative impacts.

Soil and Water Resources

Based on the analysis of water supply and cooling alternatives, and the apparent potential to cause adverse impacts to the environment or injury to other water users, staff cannot conclude at this time that the proposed project would not cause significant adverse impacts with regard to water supply. The proposed project could lead to

significant adverse impacts as a result of relying on BBID to divert fresh water from the Delta for EAEC during seasons and in quantities uncharacteristic of BBID's historic patterns of diversion. The project as proposed, may not comply with LORS from the standpoint of the California Water Code, section 1202(b), in that the proposed season and quantities of diversion to supply EAEC may not rely entirely on BBID's entitlements for appropriated water. DWR has expressed concern that its beneficial uses under the SWP, or other Delta beneficial uses including maintenance of plantlife, fish and wildlife, could be injured. (CEC 2001i, page 1)

Staff is awaiting additional information from DWR and the Applicant regarding previous Bay-Delta analyses and the relationship of BBID's water entitlements to those of the SWP and CVP, in order to more fully evaluate the potential impacts from the proposed water supply to EAEC. In particular, staff is looking to DWR for a determination on their ability to decrease withdrawals to offset BBID's anticipated increase in withdrawals to serve the EAEC. Staff is also issuing new data requests to clarify information needed from the applicant. Staff is planning to meet with all appropriate agencies to resolve these issues, and will make every effort to have the affected agencies participate in staff workshops.

Land Use

The project site is located on land that is zoned as large parcel agricultural. If Alameda County was the lead agency for this project, the project would be required to obtain a conditional use permit, which in turn would require that the County make certain findings. Staff has requested that the County staff make these findings, which the Commission staff could evaluate and incorporate into its final analysis. Staff has not yet received these conditional use permit findings from Alameda County. Therefore, staff cannot conclude that the project will comply with LORS.

The applicant is proposing to develop a power generation facility outside of the designated Urban Growth Boundary in an agricultural area that is away from existing urban uses. The conversion of at least 40 acres from an agricultural use to a nonagricultural use (the proposed power plant), including the loss of prime agricultural land, presents potential non-conformity issues with ABAG policies and could present a significant impact under CEQA.

The applicant and the County of Alameda are negotiating a mitigation agreement involving placing the remainder of the subject property not used for the construction of the power plant into preservation and either the purchasing of off-site comparable lands or easements nearby at a one-to-one ratio of land lost or contributing to the Alameda County agricultural land preservation funds. The finalized mitigation agreement would bring the project into compliance with the ABAG Regional Goals and Policies under Preservation of Agricultural Resources. As of the writing of this PSA, staff has not received a copy of the final agricultural land conversion mitigation agreement between the applicant and the County of Alameda, and cannot conclude that CEQA impacts have been mitigated or that the project will conform to applicable LORS.

Transmission System Engineering

Staff finds that the System Impact Study (SIS) analyses, reports and filings provided by the Applicant are incomplete. Based upon current study results, staff concludes that the EAEC project has some negative impacts on the transmission system and it is unclear whether and how these would be mitigated. As outlined in the power flow study results, several transmission elements potentially exceed ratings beyond reliability criteria with the interconnection of the EAEC project under normal and contingency system conditions.

However, because the SIS reports and filings not yet complete, staff is unable to fully evaluate downstream impacts, transmission facilities, and/or mitigation measures required for reliable operation of the electrical transmission system. While it appears that information requested by staff has been provided by Western (the transmission owner and Interconnection Authority) to the applicant, staff has not received such information and therefore cannot conclude that the project will conform with all system reliability LORS. Staff plan to issue new data requests in order to clarify its data needs.

Environmental Justice

EPA guidelines on environmental justice state that if 50 percent of the population affected by a project has minority or low-income status, it must be determined if these populations are exposed to disproportionately high and adverse human health or environmental impacts.

Environmental Justice Screening Analysis

In the **Socioeconomics** section of this report, staff presents the results of their "environmental justice screening analysis." The purpose of the environmental justice screening analysis is to determine whether of not there is a low-income and/or minority population within the potential affected area of the proposed site.

Socioeconomics Figure 1 identifies census blocks within six miles of the proposed project that had minority populations greater than 50 percent. Census 2000 data indicate that the minority population within the six mile radius of the project site is 34 percent. However, there are areas that have two or more contiguous census blocks with a minority population greater than 50 percent. Staff considers these areas to be pockets of predominately minority populations, therefore various technical staff will consider environmental justice impacts in their analyses.

The percent of population considered low-income or living below the poverty level ranges from 16 percent in San Joaquin County to 7 percent in Contra Costa County. In 1990, the percentage of the population living below the poverty level was 10 percent within a six-mile radius of the EAEC. This percentage is well below the threshold of greater than 50 percent that staff uses to determine if there is a significant low-income population.

When a minority and/or low-income population is identified, as is the case for this project, staff in the technical areas of air quality, public health, hazardous materials, noise, water, waste, traffic and transportation, visual resources, land use, socioeconomics and transmission line safety and nuisance. must consider possible

impacts on the minority/low-income population as part of their analysis. This "environmental justice" (EJ) analysis consists of identification of significant impacts (if any), identification of mitigation, and determination of whether there is a disproportionate impact if an unmitigated significant impact has been identified.

Environmental Justice Findings

Given that there are technical areas for which staff cannot complete their analysis, staff is unable to draw any final conclusions concerning the potential for unmitigated or disproportional adverse impacts on an EJ population.

CONCLUSION AND RECOMMENDATIONS

Summarizing the items identified above, staff cannot reach conclusions about the project's environmental or system impacts, conformance with LORS, and environmental justice, until we receive the following:

AIR QUALITY

- From the Bay Area Air Quality Management District, the PDOC and FDOC; and
- From the applicant:
  - Emissions data and other data concerning of key pieces of equipment, for the air quality analysis;
  - Evidence of ERCs for mitigation of particulate matter emissions; and
  - A complete cumulative air impacts analysis.

BIOLOGICAL RESOURCES

- A copy of the completed Biological Assessment when it is submitted to the USFWS by Western;
- The Biological Opinion from USFWS, or a draft of the Biological Opinion that provides reasonable assurance of the mitigation that will be included in the Biological Opinion;
- Further information from the applicant on habitat mitigation; and
- Written clarification from DWR on their ability to decrease withdrawals to offset BBID's anticipated increase in withdrawals to serve the EAEC and, potentially, a second consultation with NMFS.

SOIL AND WATER RESOURCES

- Written clarification from DWR on their ability to decrease withdrawals to offset BBID's anticipated increase in withdrawals to serve the EAEC; and
- The applicant's responses to water-related data requests.

LAND USE

- Conditional use permit findings from Alameda County.

TRANSMISSION SYSTEM ENGINEERING

- Completion of the System Impacts Study reports and filings, as detailed in this PSA.

Staff's goal is to resolve as many of these concerns as possible prior to release of the FSA, through PSA workshops, issue resolution workshops (to work through the more complex issues). Staff is also issuing new data requests to clarify staff's information needs. However, staff cannot predict the amount of time that will be needed for parties to provide the needed information and for agencies to issue their determinations. For that reason, staff has proposed an FSA schedule that is linked to the receipt of the critical information identified above. Taking into consideration the amount of time necessary for analysis, review, and formatting and printing of the document, staff will need at least 45 working days to complete the FSA. Therefore, staff proposes to file the FSA 45 working days after all critical pieces of information and final determinations from the relevant agencies are received.

INTRODUCTION

PURPOSE OF THIS REPORT

The Preliminary Staff Assessment (PSA)/Preliminary Environmental Assessment (Preliminary EA) presents the California Energy Commission andthe Western Area Power Administration (Western) staff's independent assessment of Calpine Corporation's Application for Certification of the East Altamont Energy Center. Because the EAEC, if built, would interconnect with Western's high voltage transmission system, the environmental review and analysis has been completed jointly by the Energy Commission (the state lead agency), and Western (the lead federal agency), for this project. To streamline the review process and eliminate overlap and duplication between the state and federal governments, this joint California Environmental Quality Act (CEQA)/National Environmental Policy Act (NEPA) process will be the basis for both the Energy Commission's decision as well as for Western's decisions.

The PSA is a staff document. It is neither a Committee document, nor a draft decision or proposed decision. This document was prepared primarily by Commission staff with input from Western's staff. Western provided more input on certain technical areas where Western has considerable expertise. Where the document mentions staff considerations, the reader should assume that staff refers to both Commission staff and Western staff, unless specifically mentioned otherwise.

The PSA describes the following:

- the existing environmental setting;
- the proposed project;
- whether the facilities can be constructed and operated safely and reliably in accordance with applicable laws, ordinances, regulations and standards (LORS);
- the environmental consequences of the project including potential public health and safety impacts;
- cumulative analysis of the potential impacts of the project, along with potential impacts from other existing and known planned developments;
- mitigation measures proposed by the applicant, staff, interested agencies and intervenors that may lessen or eliminate potential impacts;
- the proposed conditions under which the project should be constructed and operated, if it is certified;
- project alternatives; and
- requirements for project closure.

The analyses contained in this PSA are based upon information from: 1) the Application for Certification (AFC); 2) subsequent submittals; 3) responses to data requests; 4) supplementary information from local and state agencies and interested individuals; 5) existing documents and publications; and 6) independent field studies and research. The analyses for most technical areas include discussions of proposed conditions of

certification. Each proposed condition of certification is followed by a proposed means of "verification." The verification is not part of the proposed condition, but is the Energy Commission Compliance Unit's method of ensuring post-certification compliance with adopted requirements. The PSA presents conclusions and proposed conditions of certification that apply to the design, construction, operation and closure of the proposed facility.

The Energy Commission staff's analyses were prepared in accordance with Public Resources Code section 25500 et seq. and Title 20, California Code of Regulation section 1701 et seq., and the California Environmental Quality Act (CEQA) (Pub. Resources Code, § 15000 et seq.).

As a preliminary EA, this document has been prepared to comply with NEPA (Public Law 91-190, 42 U.S.C. 4321-4347, as amended), the Council on Environmental Quality Regulations and Implementing Procedures (40 CFR Parts 1500-1508), U.S. Department of Energy guidelines (10 C.F.R. 1021, Part 500 to end, revised January 1, 1997), and Western directives.

ORGANIZATION OF THE STAFF ASSESSMENT

Following the Response to Public and Agency Comments, Western's Statement of Need and Purpose, and Project Description, this PSA contains staff's environmental, engineering, and public health and safety analysis of the proposed project for 19 technical areas. Each technical area is included in a separate chapter as follows: air quality, public health, worker safety and fire protection, transmission line safety and nuisance, hazardous materials management, waste management, land use, traffic and transportation, noise, visual resources, cultural resources, socioeconomics, biological resources, soild and water resources, geology and paleontology, facility design, power plant reliability, power plant efficiency, and transmission system engineering. These chapters are followed by a discussion of facility closure and project construction and operation compliance monitoring plans, and a chapter containing an evaluation of project alternatives.

Each of the 19 technical area assessments includes a discussion of:

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

ENERGY COMMISSION SITING PROCESS

The California Energy Commission has the exclusive authority to certify the construction and operation of thermal electric power plants 50 megawatts (MW) or larger. 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, section 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, section 25519), and compliance with applicable governmental laws or standards (Pub. Resources Code, section 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)). Staff's independent review shall be presented in a report (Cal. Code Regs., tit. 20 , § 1742.5).

In addition, staff must assess the completeness and adequacy of the health and safety standards, and the reliability of power plant operations (Cal. Code Regs., tit. 20, § 1743(b)). Staff is required to coordinate 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 the California Environmental Quality Act. No Environmental Impact Report (EIR) is required because the Energy Commission's site certification program has been certified by the Resources Agency (Pub. Resources Code, § 21080.5 and Cal. Code Regs., tit. 14, § 15251 (k)). The Energy Commission acts in the role of the CEQA lead agency and is subject to all other portions of CEQA.

The staff typically prepares both a preliminary and final staff assessment. The PSA presents for the applicant, intervenors, agencies, other interested parties and members of the public, the staff's preliminary analysis, conclusions, and recommendations. Staff uses the PSA to resolve issues between the parties and to narrow the scope of adjudicated issues for the evidentiary hearings. During the period between publishing the PSA and the FSA, staff will conduct one or more workshops in the project vicinity to discuss the preliminary findings, proposed mitigation, and proposed compliance monitoring requirements. Based on the workshops and written comments, staff will refine the analysis, correct any errors, and finalize conditions of certification. Responses to written comments on the PSA will be incorporated into the Final Staff Assessment (FSA). The FSA serves as staff's testimony on the applicant's proposal.

The staff's assessment 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 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 Members' Proposed Decision (PMPD). Following publication, the PMPD is circulated for a minimum of 30 days in order to receive written public comments. At the conclusion of the comment period, the Committee may prepare a revised PMPD. A revised PMPD is required to undergo a 15-day comment period. At the close of the comment period for the revised PMPD, the PMPD is submitted to the full Energy Commission for a decision. Within 30 days of the Energy Commission decision, any party may request reconsideration of the decision by the Energy Commission.

A Compliance Monitoring Plan and General Conditions will be assembled from conditions contained in the PSA and other evidence presented at the hearings. The Compliance Monitoring Plan and General Conditions will be presented in the PMPD. The Energy Commission staff's implementation of the plan ensures that a certified facility is constructed, operated, and closed in compliance with the conditions adopted by the Energy Commission. Staff's proposed Compliance Monitoring Plan and General Conditions are included at the end of the PSA.

WESTERN ENVIRONMENTAL PROCESS

Western is a Federal power marketing agency under the U.S. Department of Energy that operates and maintains about 800 miles of high-voltage transmission lines and associated facilities in Northern California, including the Tracy Substation. Western's mission is to market power from federal hydroelectric plants such as those at Shasta and Folsom dams.

Federal law requires Western to provide entities, such as merchant power plants, open access to transmission services so that they can move power to load areas. Western provides these services through an interconnection if there is available capacity on the transmission line. Any entity requesting transmission services must abide by Western's Open Access Transmission Service Tariff and its General Requirements for Interconnection. (More information about these requirements is available on our web site at www.wapa.gov/interconn/intabout.) The developers of East Altamont have asked Western for an interconnection between the proposed power plant and our transmission system at the Tracy Substation. Western proposes to make modifications at its Tracy Substation to accommodate the interconnection.

Before Western can agree to the interconnection, it is bound by the National Environmental Policy Act to consider the project's potential environmental impacts. This Preliminary EA allows Western to analyze and judge the magnitude of environmental impacts and provides interested stakeholders, agencies and tribes an opportunity to review the document . If Western finds that there are no significant environmental impacts, it will issue an EA along with the California Energy

Commission's FSA, and will then issue a "finding of no significant impacts" and move forward with the project. If Western determines that significant impacts are a possibility it will prepare a draft environmental impact statement (EIS) instead of an EA, which entails taking a more detailed look at the impacts and alternative approaches to the project. If an EIS is needed, Western will independently publish final environmental impact statement and Record of Decision.

PUBLIC AND AGENCY COORDINATION

In preparing the PSA/preliminary EA, Energy Commission and Western staff conducted several publicly noticed joint workshops. These workshops were invaluable for bringing out comments of concerned citizens. One of the public meetings was a scoping meeting held in Livermore, Californiaon November 14, 2001. Scoping provides anybody who is interested the opportunity to identify any issues of concern to inform Western and the Energy Commission about potential environmental impacts, offer suggestions to improve the proposal, and suggest alternative actions.

Staff also coordinated with relevant local, state and federal agencies, such as the California Independent System Operator, Bay Area Air Quality Management District, U.S. Fish and Wildlife Service, California Department of Fish and Game, and the Central Valley Regional Water Quality Control Board.Further, Western sent letters of consultation to U.S. Fish and Wildlife Service, the Native American Heritage Commission and the State Historic Preservation Office. This PSA/Preliminary EA provides agencies and tribes an opportunity to review the Energy Commission and Westernstaff's preliminary analysis of the proposed project.

Written comments received from members of the public, and letters from agencies that require some form of response, have been included in thisPSA/preliminary EA. Comments received at the Energy Commission/Western scoping meeting held November 14, 2001, will be addressed in the Final Staff Assessment. No comments have been received from intervenors.

EAST ALTAMONT ENERGY CENTER (01-AFC-4)
PRELIMINARY STAFF ASSESSMENT

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PROJECT DESCRIPTION

Cheri Davis

NATURE AND PURPOSE OF PROJECT

On March 29, 2001, East Altamont Energy Center, LLC, a wholly owned subsidiary of Calpine Corporation, filed an Application for Certification (AFC) with the California Energy Commission for a nominal 1,100 MW power plant called the East Altamont Energy Center (EAEC).

The applicant's proposed site lies within a 174-acre parcel of land under the applicant's control, located in unincorporated Alameda County, approximately 1 mile west of the San Joaquin County line and 1 mile southeast of the Contra Costa County line. The site is bordered by Byron Bethany Road to the north, Kelso Road to the south, and Mountain House Road to the west. If built, the plant would occupy up to 40 acres near the center of the property, with the remainder available for lease as agricultural land. **Refer to PROJECT DESCRIPTION Figures 1 and 2** for a map of the region and the project site, respectively

PROJECT DESCRIPTION AND LINEAR FACILITIES

The generating facility would consist of three combustion turbine generators (CTGs), three heat recovery steam generators (HRSGs) with duct burners, and one condensing steam turbine generator (STG). In the combined cycle process, electricity is created both from the combustion turbines and the steam turbine. Each combustion turbine generator converts the thermal energy of natural gas to mechanical energy, which drives an electrical generator. At the same time, the thermal energy in the form of hot exhaust gas is directed to the HRSGs to produce steam, which in turn drives the steam turbine electricity generator. The design for the EAEC is such that each CTG would generate approximately 180MW at base load under average ambient conditions. The CTG exhaust gases would then be used to generate steam in the HRSGs, a process that could be augmented with duct firing. Steam from the HRSGs would then be admitted to a condensing STG, which could produce an additional 550MW under average ambient conditions. Although the AFC described the EAEC as an 1,100 MW (nominal) combined cycle power plant, the project is actually an 820 MW combined cycle power plant, with an additional 267 MW of peaking capacity provided by oversized duct burners and an oversized steam turbine generator (EAEC 2001hh).

Associated equipment would include emission control systems necessary to meet the proposed emission limits. NO_x emissions will be controlled using a combination of low NOx combustors in the CTGs and selective catalytic reduction systems in the HRSGs. A carbon monoxide catalyst would be installed in the HRSGs to limit CO emissions from the CTGs.

Additional project facilities would include:

- one nominal 100,000-pound-per-hour auxiliary boiler, to provide steam for auxiliary purposes;
- a 19-cell mechanical draft evaporative cooling tower, to provide cooling water for the steam turbine condenser;
- a 1,000kW emergency generator;
- a 370-horsepower diesel fire pump;
- a water/wastewater treatment facility;
- an ammonia storage and loading area;
- miscellaneous storage tanks associated with the water treatment system;
- a brine crystallizer; and
- a maintenance building.

The linear facilities (electric transmission facilities, natural gas line, and water supply facilities) are described below and are illustrated in **Figure 2**. **PROJECT DESCRIPTION Figure 3** depicts the site layout.

TRANSMISSION LINE FACILITIES

Western's Tracy substation is located approximately 0.25 mile west of and across Mountain House Road from the site. Electrical transmission lines would run south from the site approximately 0.5 mile to join existing 230-kW lines that connect with Western's Tracy substation.

NATURAL GAS PIPELINE

Natural gas for the facility would be delivered via approximately 1.4 miles of new 20-inch pipeline that would connect to Pacific Gas and Electric's (PG&E) existing gas transmission line southeast of the Bethany gas compressor station located to the west of the site.

WATER SUPPLY

The applicant plans to supply the plant's cooling and process water requirements (roughly 4,600 acre-feet per year, up to 7,000 AFY) with raw (i.e. untreated) water from the Byron Bethany Irrigation District (BBID), via a 2.1-mile pipeline. The applicant also indicated in their AFC that, as the community of Mountain House is developed and recycled water becomes available, BBID would be able to serve the facility in part with recycled water obtained from the Mountain House Community Services District (MHCSD) wastewater treatment plant (WWTP), resulting in a reduction in raw water use. However, this identified alternative source of cooling water is considered too speculative for the purposes of the Energy Commission's analysis of the AFC and staff's analysis assumes that the plant would rely solely on raw water.

The preferred and alternate water pipeline routes, both for the raw water and the recycled water, are shown in **PROJECT DESCRIPTION Figure 2**. For BBID raw water

conveyance, the applicant's preferred route is identified on **Figure 2** as Alternative 3e. This route would require a pump station at Canal 45 and Bruns Road and 2.1 miles of 24-inch pipeline. The pipeline would cross one high-pressure oil pipeline and Canal 45 along the gravel road, and it would require routing under the Delta-Mendota Canal. The applicant identified just two alternatives to convey water from the MHCSD WWTP to the project. The preferred route (identified on **Figure 2** as Alternative 4b) would entail the construction of approximately 4.6 miles of 24-inch pipeline from the MHCSD WWTP to the project site.

The EAEC AFC identified two possible sources of potable / domestic water to support the operation of the EAEC. These included the use of an onsite groundwater well or the use of surface water. The applicant later filed a supplement to the AFC that eliminated the former option. The applicant proposes to use BBID water for potable / domestic water purposes, which would necessitate the installation of a water treatment system to treat the water to drinking water standards.

WASTEWATER TREATMENT

The project as proposed includes a zero-liquid discharge system designed to eliminate off-site disposal of wastewater. Process wastewater would be reclaimed and reused, to the extent possible. Cooling water would be cycled three to eight times (depending on water quality) in the cooling tower; wastewater would then be directed to a brine crystallizer / dryer system, where the majority of the water would be evporated, leaving a relatively dry salt cake suitable for landfill disposal (note that this is a project change – the applicant originally proposed the use of onsite evaporation ponds). Sanitary wastewater from sinks and toilets would be discharged to an onsite septic tank and leach field.

CONSTRUCTION AND OPERATION

The project is estimated to have a capital cost of between $400 and $500 million. The applicant plans to begin construction in June 2002 and complete construction in June 2004. The project would provide for a peak of approximately 400 construction jobs over a 2-year period and up to 40 skilled positions throughout the life of the project.

The applicant proposes to operate the EAEC as a merchant power facility, selling its energy under contracts or in the spot market, through a power exchange. The EAEC would be expected to have an annual availability in the general range of 92 to 98 percent. The exact operational profile of the plant, however, would vary according to demand in the deregulated California energy market.

RESPONSE TO PUBLIC AND AGENCY COMMENTS

Below is an index of comments received from interested citizens and local governmental agencies for which a response is appropriate. A few of the questions are answered directly below but most are addressed in the applicable technical section/chapter cross-referenced below. Responses appearing in separate chapters are included under the heading "Response to Public and Agency Comments." Following the index is a copy of each interested citizen and public agency comment.

AGENCY COMMENTS ON THE PSA

ALAMEDA COUNTY COMMUNITY DEVELOPMENT AGENCY

On August 15 and October 4, 2001, staff received letters from Alameda County that provided comments from various County departments regarding the proposed EAEC. This letters contained numerous comments and recommended conditions for certification. Staff is reviewing and considering these recommended conditions and will work with the county to address their concerns. Some of Alameda's comments have already been incorporated into staff's analysis, while others will be considered for the FSA.

Specific comments are addressed in the following sections of this PSA:

- LAND USE
- VISUAL RESOURCES
- WORKER SAFETY AND FIRE PROTECTION
- TRAFFIC AND TRANSPORTATION
- SOIL AND WATER RESOURCES

BYRON BETHANY IRRIGATION DISTRICT (BBID)

On October 8 and October 30, 2001, staff received letters from Byron Bethany Irrigation District expressing numerous concerns regarding staff's analysis of water rights issues and the feasibility of alternative sources of recycled water for the EAEC. The specific comments are addressed in SOIL AND WATER RESOURCES. Any comments not addressed in this PSA will be addressed in staff's FSA.

MODESTO IRRIGATION DISTRICT (MID)

MID submitted comments to staff regarding the EAEC project interconnection to the Tracy-Westley 230 kV line (the line owned by MID and Turlock Irrigation District and the electrical grid operated by the Western Area Power Administration). MID's concerns are addressed in TRANSMISSION SYSTEM ENGINEERING.

SAN JOAQUIN COUNTY BOARD OF SUPERVISORS

Dario Marenco, Chairman of the San Joaquin County Board of Supervisors, sent a letter to Chairman Keese on June 27, 2001 to notify the Energy Commission of a resolution adopted June 26, opposing the EAEC. A corrected copy of the resolution was submitted in a letter dated July 11, 2001. Staff is reviewing and considering the Board's findings and will address the Board's concerns as appropriate in the FSA.

SAN JOAQUIN COUNTY COMMUNITY DEVELOPMENT DEPARTMENT

San Joaquin County Community Development Department submitted comments on the EAEC on August 1, 2001. Due to the project's proximity to Mountain House, and San Joaquin County in general, the Community Development Department has concerns regarding construction and project impacts relative to air quality, noise, and traffic. The Department asked that the Energy Commission's assessment address risks associated with ammonia as well as noise generated by construction, normal operations, and traffic. Staff is reviewing and considering the Department's concerns and will more fully address these concerns in the FSA.

PUBLIC COMMENTS (NON-INTERVNORS)

GARY & DOLORES KUHN

G&DK-1 *In addition to your concerns, we are deeply disturbed about the pollution at our residence (0.4 miles from project) and even more disturbed that Calpine would place this project within 0.9 miles from a school– especially since the medical response time is a good 35 to 50 minutes, depending on the time of day and freeway gridlock. If there was any disaster within the plant, such as ammonia leaks, etc., what type of warning would the residents and school be given? Should the students and residents have emergency shelters to protect themselves from hazardous vapors? And what about the animals and livestock? What they are not disclosing is that those of us that live and work in this wonderful community will have to suffer the atrocities of listening to the huge turbine engines and wonder from day to day if our lives will be snuffed out by one mistake–the release of ammonia into the air, be it by land transportation or from the plant itself. The lives of these individuals will be forever silenced and leaving no hope for the future. The corporate executives do not and will not live here in Byron; they will not worry from day to day if their life will be suddenly terminated due to a faux pas. Less we forget, 3-Mile Island and Chernobyl, and they said it would never happen. This is not the area to place a plant of this magnitude.*

(General comments are noted. See HAZARDOUS MATERIALS for a discussion of the potential for ammonia leaks.)

G&DK-2 a. *The County has designated this property "Prime Agriculture." This plant does not conform to the County's General Plan. Agriculture land is becoming so sparse because of projects like this. The choice has to be made – FOOD or ELECTRICITY – which is more important? I know we could survive without electricity.*

(See LAND USE.)

b. *This plant will also make the value of the surrounding property go down .*

(See SOCIOECONOMICS.)

c. Calpine has a lease/option on a piece of property adjoining the proposed site. Will they re-zone this property and make it industrial paving the way for more industry? Again–not what this area's General Plan is designated for.

(See LAND USE)

G&DK-3 *Attending a previous meeting–the subject of noise was addressed. Calpine staff assured us that it would be "quiet as a library." After visiting the Los Medanos Plant, we have to disagree. It was overwhelmingly loud, not to mention the ammonia smell, which took your breath away and burned you eyes.*

(See NOISE.)

G&DK-4 *The 10 acres dedicated to two evaporation ponds are a big concern.*

a. Are we the only plant in California that has holding ponds, and why?

b. Environmental issues are tremendous. How will you keep the wildlife and endangered species such as the Kit Fox, Red Legged Frog, Spotted Salamander, Swensen Hawk, Burrowing Owl, etc., from getting into these ponds and drinking this contaminated water? It seems that the monofilament will be a hindrance to animals that fly into it and get caught up in the line.

c. Are the holding ponds going to have an odor that the residents and school children will be breathing constantly.

d. *Can we be reassured that our water will not be polluted?*

Response: the applicant amended the project proposal and no longer plans to use evaporation ponds. The applicant replaced the evaporation ponds with a brine crystallizer / dryer system per Supplement B to the AFC.

G&DK-5 *Besides the plant itself being a visual eyesore, there is no landscaping on earth that would conceal the monstrosity of this plant. This is one more reason that this is not an appropriate placement of this plant. It would be visible from any direction for miles. How is it possible to place this project along designated scenic roads?*

(See VISUAL RESOURCES)

G&DK-6 *The quoted approximate distance of Calpine's primary route of 1.4 miles is in reality approximately 2 miles. Also, why are they stating that Kelso Road is their primary route, yet they are contracting easements from property owners from their second and third routes? Does Calpine have the right to Eminent Domain through private properties?*

Response: No, Calpine does not have the right of Eminent Domain. However, Calpine may enter into agreements for easements with property owners as they wish. Calpine may want to have easements for other linear routes as a backup plan.

G&DK-7 *How brightly lit is a plant of this magnitude?*

(See VISUAL RESOURCES)

G&DK-8 *Calpine has not committed to saying how many gallons of ammonia will be transported and are vague about how many times a week.*

(See HAZARDOUS MATERIALS)

G&DK-9 *School bus route is on both Kelso and Mountain house Road bordering the plant. Students will be exposed to high volume of pollution on a daily basis.*

(See AIR QUALITY)

G&DK-10 *How close to the center of the earthquake fault is this area?*

(See GEOLOGY AND PALEONTOLOGY)

G&DK-11 *Why is it we are the only site that has residents and schools less than a mile from the plant? We noted that there were only industrial sites round the plants in Pittsburg. No homes or schools. That is where the plants belong–in that kind of environment–not on Prime Agricultural Land.*

Response: The Energy Commission is not involved in the site selection process. Once an applicant selects a site and files an Application for Certification, it is the responsibility of Energy Commission staff to conduct an independent evaluation of the project. Part of staff's analysis is the evaluation of site alternatives (See ALTERNATIVES). Staff encourages the public to comment on this PSA, including the analysis of site alternatives.

G&DK-12 *Why aren't plants such as Calpine put on Government land?*

Response: In the deregulated California electricity market, the majority of new power plants are built by private business owners, on private land.

G&DK-13 *It was quoted in the Tri-Valley Herald that "California is facing a glut of electricity as a result of buying too much power through long-term contracts according to energy experts. The state even could find itself in the paradoxical position of encouraging Californians to use more electricity to help the state avoid selling large amounts of unused power at a loss." Another reason we do not need this plant.*

Response: In the deregulated market, the project owner takes the risk that there may at some point be an energy glut, which would drive down electricity prices and affect their bottom line. In other words, the project owner makes their own judgement about market demand.

G&DK-14 *According to the Environmental Protection Agency – San Joaquin valley ranks just behind Los Angeles, Housing, and California's southeast desert, as the worst ozone regions in the nation. What consideration has been given to the impact on the air quality in San Joaquin county, (already in non-compliance) which would be directly affected by the proposed plant?*

(See AIR QUALITY)

G&DK-15 *At Calpine meeting we were led to believe that the power would benefit the surrounding counties or at least California. Calpine being a merchant plant- the owners may sell the power from this merchant plant into the energy system to any buyer willing to make a purchase. Rumors have it that this may be Nevada and Oregon. Why would Alameda County allow a plant to be built on Prime Agriculture Land when it possibly will not even benefit our State: And – how is it allowed on a scenic highway?*

Response: You are correct that Calpine, in operating a merchant plant, may sell electricity to any buyer they choose – in state or outside the state. Your concerns about the plant being built on Prime Agricultural land are addressed in LAND USE and your question about the scenic highway is addressed in VISUAL RESOURCES.

G&DK-16 *Why not locate the plant on the far north side of the project site away from residents and school?*

(See response to G&DK-11)

G&DK-17 *Why not aqua-ammonia instead of anhydrous ammonia? Accidents do happen (article faxed).*

(See HAZARDOUS MATERIALS)

G&DK-18 *I've visited other plants both under construction and partially running. The noise and commotion from all the construction going on and the noise from the plant in operation was not living up to the description that Calpine described as "quiet as a library"!*

(See NOISE)

G&DK-19 *Calpine can debate all they want on what kind of tree or landscaping is going to do the best job – bottom line is – there is no tree or landscaping that can hide the enormous size of this plant. The Yuba Sutter plant we visited was not hidden – an indication of what our visual impact will be. Our visual quality will be diminished for life. Our view of Clifton Court Forebay will be gone. When all is done we will be the ones left to have to look at and hear the plant every single day of our lives.*

(See VISUAL RESOURCES)

G&DK-20 *I would like to know if Calpine has addressed the Resolution R-01-406 from the Board of Supervisors of San Joaquin county? (faxed).*

Response: The Energy Commission received a copy of this Resolution and takes not of San Joaquin County's opposition to this power plant in Alameda County. The Resolution has been entered into the record for consideration by the Commissioners during the decision phase of our certification process.

G&DK-21 *Has Calpine signed contracts with any facilities to purchase power?*

Response: The Energy Commission has no knowledge of specific contracts to sell power from the EAEC.

JACK D. AND DONNA HAYES

J&DH-1 *Mandatory routing of all ammonia shipments. Never past the school anytime day or night. Deliver from Byron Highway only.*

(See HAZARDOUS MATERIALS)

GORDON & MARIANNE GRIFFITH

G&MG-1 *I realize that this meeting is for the consideration of the East Altamont Energy Center (Calpine's) application, but I would like to just make a general statement as to our concerns.*

We have been getting notices upon notices of the up-coming meetings and there have been many paper articles about the applications for mew power plants in our area. To our north there is the plant on Kelso/Mt. House Road; to the northwest there is the Tesla Power Plant; to the east there is the power plant on Schulte Road; to the south, two of our neighbors have been talked to by companies about putting in power plants, and in Stockton there is discussion of another power plant. Now, existing 500 feet from our home is the Tesla substation (non-gas-powered). My husband and I moved from our ranch home to another site on our property so that we weren't being shocked by the results of the 500-kv line that is 500 feet or less from the house. We personally are being infested by these energy plants.

Although I realize that there is an added need for energy, I don't think that the plants should be located near populated areas. I believe that there are many unanswered questions that need to be addressed, as to the potential hazards of these plants. My concern is also that some of the people in Tracy are still unaware of these proposed plants and the effect that there may be on the community.

Response: This document contains staff's independent assessment of the applicant's project as proposed, and includes a review of many potential impacts of the proposed facility. We encourage you to participate in our process and provide comments on staff's analysis of the project so that we may address your concerns in full.

G&MG-2: *I have many concerns about the Calpine or any other energy business, constructing and/or running a 1,100-MW natural gas-fired combined cycle power plant in our area.*

I do commend Calpine for the community service and contributions to our Mt. House School and 4-H Club. It is a good gesture towards the community, but at what cost to those who live in the direct area and surrounding areas?

(See response to G&MG-1)

G&MG-2: *Mt. House School has only 50± students. We strive for the best education for our students. We don't have the 1,000 to 5,000 students that the cities have, but our students are no less important to us. My grandchildren attend Mt. House School, as I did. So, because we have*

a less number of students in our school, does this mean that if there was, God forbid, an "accident" or "leak," our students are sacrificed and not the hundreds or thousands at other sites? The death of our students and community doesn't mean as much?

Response: Our analysis considers a school to be a "sensitive receptor" whether it has 2 students or 5,000 students. (See HAZARDOUS MATERIALS)

G&MG-3 *The safety of the gas pipeline to those in the immediate area is an issue to me also. We have been assured, by Calpine, that there isn't a danger to anyone in the area. There is always a potential danger when working in or around the pipeline area. The ammonia used at this plant is another issue. We are also assured that there is no fumes or smell coming from these plants. I have not been to a working plant, but understand from those who have been to one that the ammonia fumes are eye burning, to say the least, and the noise is unbearable.*

(See HAZARDOUS MATERIALS)

G&MG-4 *I am not against progress or industry, but I believe that it should be located away (way away) from the communities where we live and our generations are growing up and being schooled. Our prime agriculture land is being taken over by industrial and housing developments, and malls.*

We have and live in a very rural area. Sure, there are not hundreds or even thousands of human beings living in our area. We are an agriculture/rural area. Many of us have to work outside our homes to make a living, this is true, but our land and our farming is important to us. My land has been in our family for five generations. It is something that we have been very proud of. A part of our land we have only had for three generations. I have watched, as our land has been cut and surveyed and trespassed and easemented to death. We have been taken over in the name of "progress and need." Our property is only 40 percent useable, except for our dry-land farming or grazing. All in the name of "progress."

As the Commission is looking over these applications, please consider the people in the community who live, play, and educate in the immediate area of ANY of the energy centers. I believe that Calpine is a large company and has the ability to locate just about anywhere they wish. With the energy shortage and being threatened with blackout, we do need to look into alternative energy programs. I would only hope that Calpine, the new Tesla Power Project, and other gas-powered centers look somewhere where there isn't human life for miles and miles, and isn't a threat to rural communities.

Response: This document contains staff's independent assessment of the applicant's project as proposed, and includes a review of site alternatives, land use impacts, and public health impacts, to name a few of the issues you mentioned. We encourage you to participate in our

process and provide comments on staff's analysis of the project so that we may address your concerns in full.

MRS. JANICE HOLLY-SHEEHAN

JHS-1 *My concern is that Calpine wants to build an 11k-megawatt electrical plant .9 of a mile from the school of Mountain House. I am concerned about an accident—there is no guarantee that an ammonia slip (no matter what the circumstances are that cause the slip) of ammonia or the quantity of released will never happen. I am not concerned with the health of the individuals in the surrounding area will be effected. I am not comfortable with Calpine's answer as how our safety will be assured and medical assistance received in a timely manner at our site. I am receiving the message from Calpine that since there is a smaller population in Byron over a city such as Livermore, Pleasanton, Oakland, the loss of 50 individuals is insignificant to the loss of a larger, more populated community. Calpine states they did not choose the site based on the local population, however, it is stated in the application (or description of the area). I believe this is one of their criteria to build the electrical plant in Byron not the location of their "hook-ups" to other facilities. The electrical plant is being constructed at the expense of the community—It is changing their environment, bringing noise pollution, air pollution, risk, effecting the land that was zoned agricultural and using it for industrial, changing the life of "Rural America". I understand that there are other issues surrounding soil, historical value of the city water, and that they also will be effected negatively if the plant is built in Byron. I do not want the 11k megawatt electrical plant built in Byron .9 miles from the school or near the residence of Mr. and Mrs. Gary Kuhn .4 miles from the plant. Keep industry where it belongs, not in the rural, agricultural area of Byron. Also, will there be verification test of the startup and shutdown emissions prior to the granting of the permit to operate?*

Response: Your comments and concerns are noted. Many of your concerns are addressed in this document (See AIR QUALITY, PUBLIC HEALTH, and HAZARDOUS MATERIALS) As stated in response to JHS-1, we encourage you to participate by providing comments on our PSA so that we may better address your concerns in the FSA.

ENVIRONMENTAL ASSESSMENT

AIR QUALITY

Tuan Ngo, P.E.

INTRODUCTION

This analysis addresses the potential air quality impacts resulting from criteria air pollutant emissions created by the construction and operation of the East Altamont Energy Center (EAEC). Criteria air pollutants are those for which a state or federal standard has been established. They include nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), ozone (O_3) and its precursors: oxides of nitrogen (NO_x) and volatile organic compounds (VOC), particulate matter less than 2.5 microns ($PM_{2.5}$) and less than10 microns in diameter (PM_{10}) and their precursors (NO_x, VOC, SO_2), and lead (Pb).

In completing this analysis, the California Energy Commission staff evaluated the following major points:

- whether the project is likely to conform with applicable Federal, State and the Bay Area Air Quality Management District (District) air quality laws, ordinances, regulations and standards, as required by Title 20, California Code of Regulations, section 1742.5 (b);
- whether the project is likely to cause significant air quality impacts, including new violations of ambient air quality standards or contributions to existing violations of those standards, as required by Title 20, California Code of Regulations, section 1742 (b); and
- Whether the mitigation proposed for the project is adequate to lessen the potential impacts to a level of insignificance, as required by Title 20, California Code of Regulations, section 1744 (b).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

FEDERAL

The federal Clean Air Act requires any new major stationary sources of air pollution and any major modifications to major stationary sources to obtain a construction permit before commencing construction. This process is known as New Source Review (NSR). Its requirements differ depending on the attainment status of the area where the major facility is to be located. Prevention of Significant Deterioration (PSD) requirements apply in areas that are in attainment of the national ambient air quality standards. The non-attainment area NSR requirements apply to areas that have not been able to demonstrate compliance with national ambient air quality standards. The entire program, including both PSD and non-attainment NSR permit reviews, is referred to as the federal NSR program.

Title V of the federal Clean Air Act requires states to implement and administer an operating permit program to ensure that large sources operate in compliance with the requirements included in Title 40, Code of Federal Regulations, Section 70. A Title V

permit contains all of the requirements specified in different air quality regulations which affect an individual project.
The U.S. Environmental Protection Agency (EPA) has reviewed and approved the Bay Area Air Quality Management District's regulations and has delegated to the District the implementation of the federal PSD, Non-attainment NSR, and Title V programs. The District implements these programs through its own rules and regulations, which are, at a minimum, as stringent as the federal regulations.

The EAEC's gas turbines are also subject to the federal New Source Performance Standards (NSPS). These standards include a NO_x emissions concentration of no more than 75 parts per million (ppm) at 15 percent excess oxygen (ppm@15%O2), and a SO_x emissions concentration of no more than 150 ppm@15%O2.

STATE

California State 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 cause injury, detriment, nuisance, or annoyance to any considerate 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."

LOCAL

As part of the Commission's licensing process, in lieu of issuing a construction permit to the applicant for the EAEC, the District will prepare and present to the Commission a Determination of Compliance (DOC). The DOC will evaluate whether and under what conditions the proposed project will comply with the District's applicable rules and regulations, as described below. The Commission staff will coordinate its air quality analysis with the District staff as they prepare the DOC, will review and comment on the Preliminary DOC to identify any issues of concern, and will incorporate the Final DOC recommended conditions of certification in its Final Staff Assessment.

The project is subject to the specific District rules and regulations that are briefly described below:

Regulation 2

Rule 1 – General Requirements. This rule contains general requirements, definitions, and a requirement that an applicant submit an application for an authority to construct and permit to operate.

Rule 2 – New Source Review. This rule applies to all new and modified sources. The following sections of Rule 2 are the regulations that are applicable to this project.

- Section 2-2-301 - Best Available Control Technology (BACT) Requirement: This rule requires that BACT be applied for each pollutant which is emitted in excess of 10.0 pounds per day.
- Section 2-2-302 - Offset Requirement, Precursor Organic Compounds and Nitrogen Oxides. This section applies to projects with an emissions increase of 50 tons per year

or more of organic compounds and/or NO_x. Offsets shall be provided at a ratio of 1.15 tons of emission reduction credits for each 1.0 ton of proposed permitted emissions.

- Section 2-2-303 - Offset Requirements, Total Particulate Matter, PM_{10} and Sulfur Dioxide: If a Major Facility (a project that emits any pollutant greater than 100 tons per year) has a cumulative increase of 1.0 ton per year of PM_{10} or SO_2, emission offsets must be provided for the entire cumulative increase at a ratio of 1.0:1.0.
- Emission reductions of nitrogen oxides and/or sulfur dioxide may be used to offset increased emissions of PM_{10} at offset ratios deemed appropriate by the Air Pollution Control Officer.

  A facility which emits less than 100 tons of any pollutant may voluntarily provide emission offsets for all, or any portion, of their PM_{10} or sulfur dioxide emissions increase at the offset ratio required above (1.0:1.0).

- Section 2-2-606 - Emission Calculation Procedures, Offsets. This section requires that emission offsets must be provided from the District's Emissions Bank, and/or from contemporaneous actual emission reductions.

Rule 7 – Acid Rain. This rule applies the requirements of Title IV of the federal Clean Air Act, which are spelled out in Title 40, Code of Federal Regulations, Section 72. The provisions of Section 72 will apply when EPA approves the District's Title IV program, which has not been approved at this time. The Title IV requirements will include the installation of continuous emission monitors to monitor acid deposition precursor pollutants.

Regulation 6

Particulate Matter and Visible Emission. The purpose of this regulation is to limit the quantity of particulate matter in the atmosphere. The following two sections of Regulation 6 are directly applicable to this project:

- Section 301 - Ringelmann No. 1 Limitation: This rule limits visible emissions to no darker than Ringelmann No. 1 for periods greater than three minutes in any hour.
- Section 310 - Particulate Weight Limitation: This rule limits source particulate matter emissions to no greater than 0.15 grains per standard dry cubic foot.

Regulation 9

Rule 1 – Limitations.

- Section 301: Limitations on Ground Level Sulfur Dioxide Concentration. This section requires that emissions of sulfur dioxide shall not impact at ground level in excess of 0.5 ppm for 3 consecutive minutes, or 0.25 ppm averaged over 60 minutes, or 0.05 ppm averaged over 24 hours.
- Section 302: General Emission Limitation. This rule limits the sulfur dioxide concentration from an exhaust stack to no greater than 300 ppm dry.

Rule 9 – Nitrogen Oxides from Stationary Gas Turbines. Effective January 1, 1997, this rule will limit gaseous fired, SCR equipped, combustion turbines rated greater than 10 MW to 9 ppm@15%O2.

Regulation 10

Rule 26 – Gas Turbines - Standards of Performance for New Stationary Sources. This rule adopts the national maximum emission limits (40 CFR 60) which are 75 ppm NO_x and 150 ppm SO_2 at 15 percent O_2. Whenever any source is subject to more than one emission limitation rule, regulation, provision or requirement relating to the control of any air contaminant, the most stringent limitation applies.

SETTING

METEOROLOGY AND CLIMATE

The topography of the area varies from rolling hills with relatively flat benches and valleys to steep hills and rugged canyons. The climate of the area is characterized by mild, rainy winters, and warm, dry summers. The mean annual temperature is about 60°F, with the normal seasonal temperature range between 25°F during winter pre-dawn mornings to 110°F on an occasional summer afternoon.

During winter, storms affect the region, attended by southerly or southwesterly winds and short periods of rain. Occasionally, strong northerly surface winds with gusts in excess of 30 meter per second (m/sec) could happen for a day or two during this period. During December and January, fog frequently forms in the San Joaquin Valley and moves over the site.

In summer, air over land is heated by solar radiation more rapidly than air over the cooler Pacific Ocean. This causes land air to rise, developing a circulation which draws ocean air inland. This sea breeze often develops in the afternoon when modified marine air moves through the pass and enters the area during the summer months. This breeze persists into the evening and occasionally throughout the night, resulting in cool temperatures. If the marine layer is sufficiently deep, ground-hugging clouds could form within several miles of the area's western boundary. The clouds usually dissipate during the afternoon. The sea breeze ranges between 5 to 15 m/sec, but may exceed 20 m/sec.

Spring and autumn are typically transitional periods, during which no exceptional meteorological phenomena occur.

Most of the precipitation occurs between October and April, with very little rainfall during the warmer months. The highest and lowest rainfalls on record are 30.8 inches and 5.4 inches respectively. On the average, the area receives about 14.9 inches annually. The area rarely experiences severe weather, with thunderstorms occurring fewer than ten days per year and hail even less frequently.

The San Joaquin Valley Unified Air Pollution Control District collects meteorological data at the project site. The data collected include wind directions, wind speed, temperature, and atmospheric stability class. The Bay Area Air Quality Management District (District) has determined that the collected meteorological data are

representative of the area's meteorology, and that it is appropriate to use for air quality dispersion modeling analysis for this project.

Quarterly and annual wind roses (graphic representations of wind speeds and directions), which were based on data collected in 1999, are shown in Figures 8.1-7 a through g of the AFC (EAEC, 2001a). At the project site, the winds blow predominately from the west from April through September. From October through February, the wind directions are more variable, with winds blowing predominately from the north, southeast and west.

Mixing heights in the area, which represent the altitudes to which different air masses mix together, have been estimated to range from a low of approximately 80 meters in the morning to a high of 2,300 meters in the afternoon. High mixing heights, normally associated with unstable conditions, can lead to greater dispersion of air contaminants (Smith et al. 1984). When the mixing height is low and the wind is calm, air contaminants can be trapped near the ground.

EXISTING AMBIENT AIR QUALITY

The Federal Clean Air Act and the California Clean Air Act both require the establishment of ambient concentrations of air contaminants called ambient air quality standards (AAQS). The state AAQS, established by the Air Resources Board (ARB), are typically lower (more protective) than the federal AAQS, which are established by the federal Environmental Protection Agency (EPA). The state and federal air quality standards are listed in **AIR QUALITY Table 1**. As indicated in **AIR QUALITY Table 1**, 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 and $\mu g/m^3$).

AIR QUALITY Table 1
Ambient Air Quality Standards

Pollutant	Averaging Time	California Standards	Federal Standards	
			Primary	Secondary
Ozone(O_3)	1-hour	0.09 ppm (180 μg/m^3)	0.12 ppm (235 μg/m^3)	Same as primary
	8-hour		0.08 ppm (157 μg/m^3)	
Particulate Matter (PM_{10})	Annual Geometric Mean	30 μg/m^3	---	Same as primary
	24-hour	50 μg/m^3	150 μg/m^3	
	Annual Arithmetic Mean	---	50 μg/m^3	
Fine Particulate Matter ($PM_{2.5}$)	24-hour	No separate standard	65 μg/m^3	Same as primary
	Annual Arithmetic Mean		15 μg/m^3	Same as primary
Carbon Monoxide (CO)	1-hour	20 ppm (23 mg/m^3)	35 ppm (40 mg/m^3)	None
	8-hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)	
Nitrogen Dioxide (NO_2)	1-hour	0.25 ppm (470 μg/m^3)	---	Same as primary
	Annual Arithmetic Mean	---	0.053 ppm (100 μg/m^3)	
Lead(Pb)	30-day	1.5 μg/m^3	---	Same as primary
	Cal. Quarter	---	1.5 μg/m^3	
Sulfur Dioxide (SO_2)	Annual Arithmetic Mean	---	0.03 ppm (80 μg/m^3)	---
	24-hour	0.04 ppm (105 μg/m^3)	0.147 ppm (365 μg/m^3)	---
	3-hour	---	---	0.5 ppm (1300 μg/m^3)
	1-hour	0.25 ppm (655 μg/m^3)	---	---
Sulfates	24-hour	25 μg/m^3	No federal standard	
H_2S	1-hour	0.03 ppm (42 μg/m^3)	No federal standard	

Source: California Air Resources Board

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 non-attainment for an air contaminant if that contaminant standard is violated. Where not enough ambient data are available to support designation as either attainment or non-attainment, the area can be designated as unclassified. The unclassified area is normally treated the same as an attainment area for regulatory purposes. An area could be in attainment for one air contaminant while in non-attainment for another, or in attainment for the federal standard and in non-attainment for the state standard for the same air contaminant. The entire area within the boundaries of the air district is usually evaluated to determine the district's attainment status. The District includes all or portions of nine counties in the Bay Area: all of San Francisco, San Mateo, Santa Clara, Alameda, Contra Costa, Napa and Marin Counties, and the southwest portion of Solano County and the southern portion of Sonoma County.

AIR QUALITY Figure 1 summarizes the historical air quality data for the project location for PM_{10}, CO, SO_2, O_3, and NO_2. In **AIR QUALITY Figure 1**, the normalized concentrations represent the ratio of the highest measured concentrations in a given year to the most stringent applicable national or state ambient air quality standard. Therefore, normalized concentrations lower than one indicate that the measured concentrations were lower than the most stringent ambient air quality standard. Based on the ambient concentration data collected, the area is consistently maintained below the most stringent ambient air quality standards for all criteria pollutants except for PM_{10} and ozone. Below is an in-depth discussion of ambient air quality conditions in the area for ozone, NO_2, CO and PM_{10}.

OZONE

Ozone is not directly emitted from stationary or mobile sources, but is formed as the result of chemical reactions in the atmosphere between directly emitted air pollutants. Nitrogen oxides and hydrocarbons interact in the presence of sunlight to form ozone.

The ambient ozone concentrations recorded between 1992 and 2000 are presented in **AIR QUALITY Figure 1** and have ranged from 11 to 15 parts per hundred million (pphm). The area experiences 5 to 22 days of violations of the state 1-hr ozone air quality standard each and every year since 1992. The available ambient ozone data show a slight increasing trend of ozone concentrations since 1992, and there is no clear indication that the ozone air quality is getting any better.

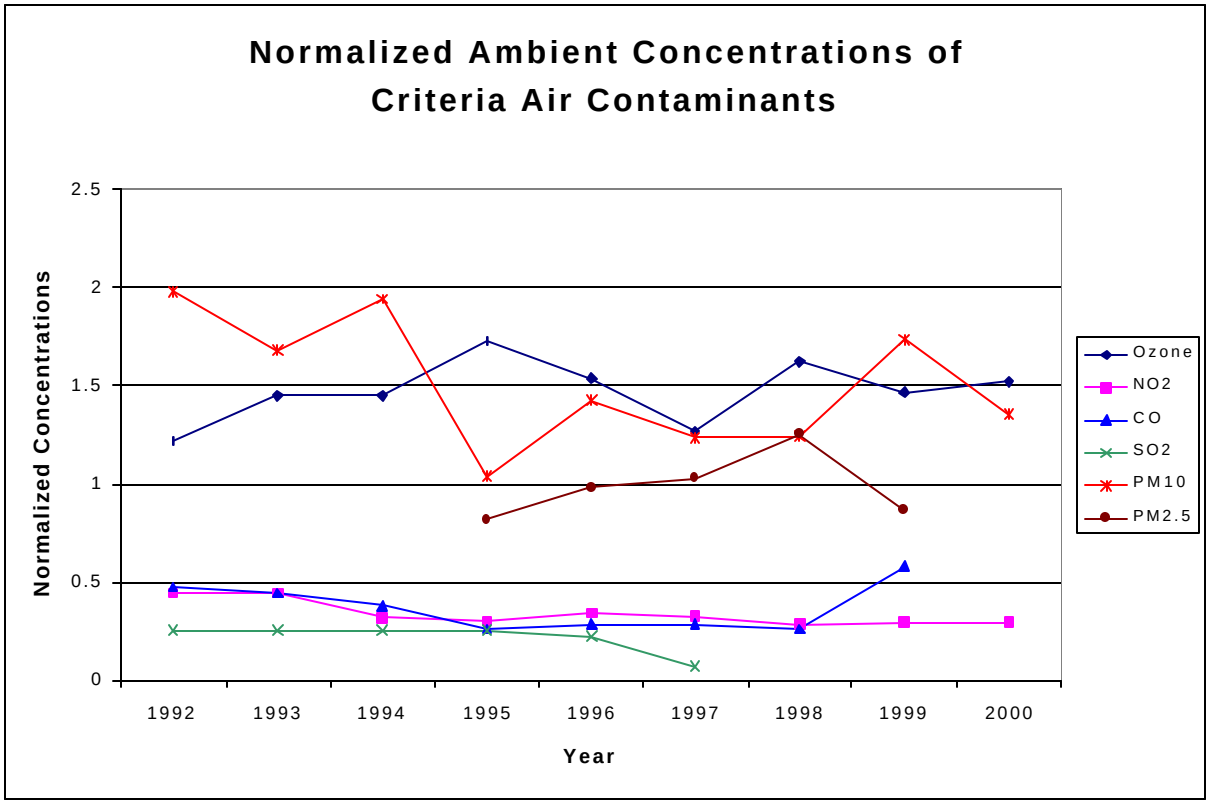
The 8-hour ambient ozone concentration recorded at the area was 9 pphm in 1992 and increased steadily to 11 pphm in 2000. These data indicate that the area would exceed the new federal 8-hour ozone standard (8 pphm) for each and every year since 1992. [The EPA has established an 8-hour ozone standard, but it has not make a finding that the District would be classified as non-attainment for such standard.]

Nitrogen Dioxide

Ambient NO_2 levels measured between 1992 to 2000 are no more than half of the most stringent NO_2 ambient air quality standards, as shown in **AIR QUALITY Figure 1**. Most of the NO_x emitted from combustion sources is in the form of NO, while the balance is NO_2. NO is oxidized in the atmosphere to NO_2, but some level of photochemical activity is needed for this conversion. This is why the highest concentrations of NO_2 occur

during the fall and not in the winter, when atmospheric conditions favor the trapping of ground level releases but lack significant photochemical activity (less sunlight). In the summer, the conversion rates of NO to NO_2 are high, but the relatively high temperatures and windy conditions (atmospheric unstable conditions) disperse pollutants, preventing the accumulation of NO_2 to levels approaching the 1-hour ambient air quality standard.

AIR QUALITY Figure 1



Notes: CO, NO_x and Ozone data are from Livermore monitoring station, $PM_{2.5}$ data are from Stockton and SO_2 data are from Fresno monitoring station.
Source: Air Resources Board

Carbon Monoxide (CO)

The highest CO concentration levels measured between 1992 to 1999 are at least 40 percent lower than the most stringent California ambient air quality standards (see **AIR QUALITY Figure 1**). The highest concentrations of CO occur when low wind speeds and a stable atmosphere trap the pollution emitted at or near ground level in what is known as the stable boundary layer. These conditions occur frequently in the wintertime late in the afternoon, persist during the night, and may extend one or two hours after sunrise. Since the mobile sector (cars, trucks, and buses) is the main source of CO, we expect ambient concentrations of CO to be highly dependent on its emissions.

Particulate Matter

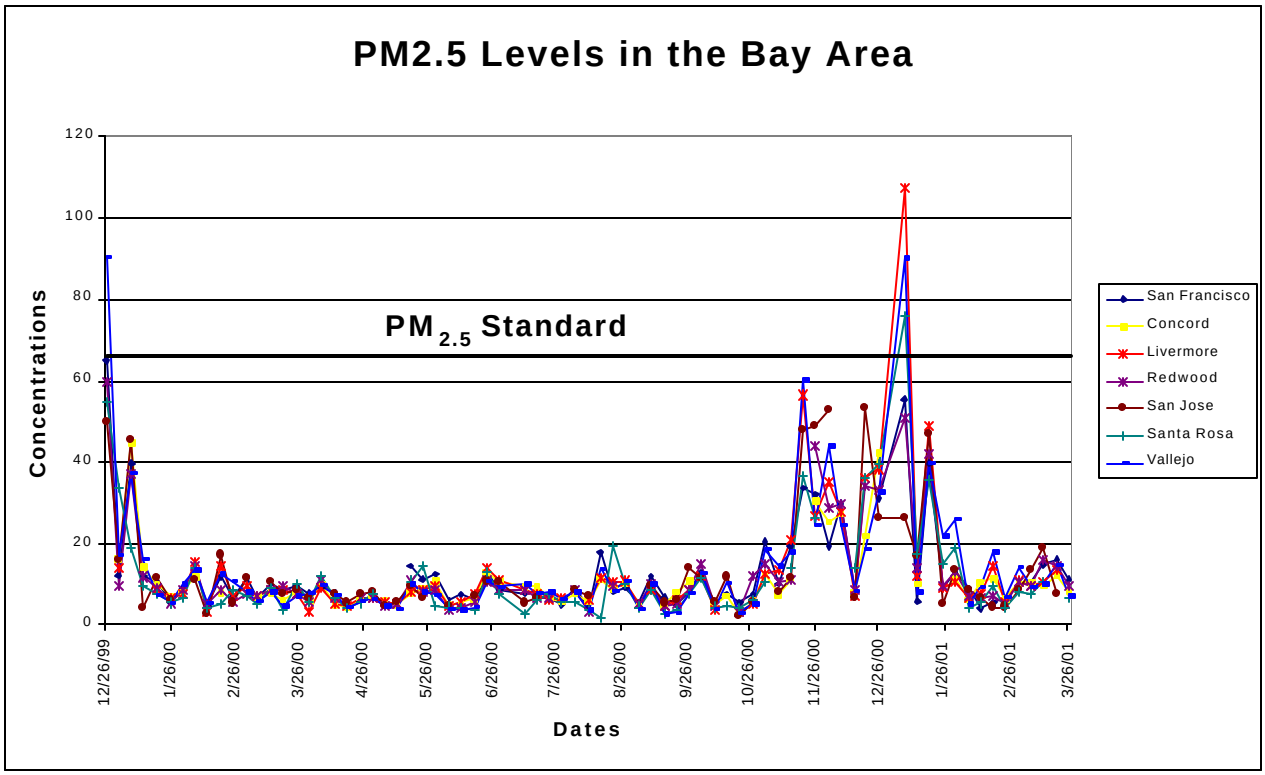
As shown in **AIR QUALITY Figure 1**, PM_{10} concentrations measured at the area show that the area has experienced violations of the state 24-hour PM_{10} standard each and

every year between 1992 and 2000. During this period the area has experienced between 6 and 30 calculated days of the state 24-hour PM_{10} air quality standard. The highest PM_{10} concentrations are normally measured between the months of October through February, especially during evening and night hours. During wintertime, high PM_{10} episodes, the main sources of PM_{10} contributions are wood smoke, combustion of fossil fuels, and entrained dust particles (BAAQMD 2000).

Fine Particulate Matter

Air Quality Figure 2 shows the available $PM_{2.5}$ concentrations measured at various air quality monitoring stations in the Bay area during the period of December 1999 to March 2001. Air Quality Figure 5 shows that the $PM_{2.5}$ concentrations measured in Livermore were among the highest in all the counties of the Bay Area District air basin. Source: Air Resources Board

AIR QUALITY Figure 2



PROJECT EMISSIONS

CONSTRUCTION ACTIVITIES

Construction of the proposed project will last approximately 24 months. Construction generally consists of two major activities: site preparation and installation of major equipment and structures. The applicant provided estimated peak daily and annual construction equipment exhaust emissions (EAEC, 2001a). These estimated

construction emissions are identified in Section 8.1E-1 of the AFC and summarized in **AIR QUALITY Table 2**. Staff reviewed the applicant's estimated construction emissions, and believes that they are accurate.

Emissions from construction equipment exhaust, such as vehicles and internal combustion engines, are also expected during the project construction phase. A small amount of hydrocarbon emissions may also occur as a result of the temporary storage of petroleum fuel at the site.

AIR QUALITY Table 2
Construction Emissions

Construction Emission Sources	NO_x	SO_2	VOC	CO	PM_{10}
Daily (lbs/day)	380	10	100	1100	70
Annual (tons/yr)	25	1	6	58	2
Fugitive Dust (tons/yr)					5

Sources: EAEC, 2001a. AFC, Appendix 8.1E.

PROJECT OPERATION

The project will be built with the following major components:

- Three natural gas fired, General Electric (GE) Frame 7FB combustion turbines,
- Three heat recovery steam generators (HRSG), each equipped with a 732 MMBTU duct burner,
- One steam turbine,
- One natural gas-fired 100,000 lbs/hr auxiliary boiler,
- One 19-cell cooling tower,
- One diesel fueled fire pump, and
- One natural gas-fired emergency generator.

The turbines will be operating in combined cycle mode to produce approximately 1,100 MW of electricity. The applicant proposes to equip each combustion turbine with a dry low NO_x combustion technology and a selective catalytic reduction (SCR) system in the HSRG, which together limit the NO_x emissions to 2.5 ppm@15% O_2. To control the CO and VOC emissions, the applicant proposes to equip each combustion turbine/HRSG with a high-temperature oxidation catalyst system, which limits the CO emissions to 6 ppm and the VOC emissions to 2 ppm (EAEC, 2001a).

The applicant is requesting that the project be analyzed with the following assumptions:

- each turbine/HRSG operates at 4 hours a day without the operation of the duct burner,
- each turbine/HRSG operates at 16 hours a day with the duct burner in operation,
- 50 cold-starts, 250 hot-starts and 300 shutdowns for both turbines each year (EAEC, 2001a. AFC Appendix 8.1A). A hot start would occur after an overnight turbine

shutdown. The applicant states that the duration of a hot start is approximately one hour, and as much as three hours for a cold start (EAEC, 2001a).

The applicant also requests that the project emissions include the emissions from the natural gas-fired auxiliary boiler. The auxiliary boiler is expected to operate about 8 hours a day and no more than 3,000 hours annually (EAEC, 2001a).

The operation of the emergency generator and the diesel fire pump are expected only when the turbines are not in operation; therefore, their normal operation emissions are not to be included in the total emissions of the facility. However, either piece of equipment can be tested at any one day for a period no longer than 1 hour (EAEC, 2001a). Therefore, the emissions from these two pieces of equipment will be included in the facility's total emissions.

The applicant provided staff their estimates of the facility's hourly, daily and annual emissions (EAEC, 2001a AFC Appendix 8.1A). Staff has asked for manufacturer's information to substantiate the applicant's estimated emissions; however, because the project is still in the conceptual phase, much of the requested information is preliminary or not available. These include the specifications and emissions guarantee for the turbine, the duct burner, the auxiliary boiler and their control systems. The applicant has provided some preliminary emissions data and the SCR system emissions guarantee for the turbine/HRSG power train (EAPC, 2001c).

Staff evaluated the applicant's emissions estimates and believes that they have been underestimated, especially for the turbine start-up and shut down emissions. The applicant, in its latest Data Response (Calpine, 2001c) provided some preliminary data from GE, which indicated that the turbine's uncontrolled, steady state emissions are higher than the applicant's provided start up emissions. A turbine's start up emissions are generally higher than the uncontrolled, steady state operation emissions. Therefore, staff will have to re-estimate the total facility emissions to determine the project's emission impacts and possible mitigation.

AIR QUALITY Table 3 lists the staff's estimated project emission profile for the facility during periods of cold start, hot start and steady state operation. [The applicant estimates that each turbine/HRSG power train will emit approximately 80 pounds of NO_x, 840 pounds of CO and 16 pounds of VOC each hour for each cold or hot start. The applicant also estimates that each cold start will last 3 hours and each hot start will last one hour.]

The East Altamont facility would employ three-GE frame 7FB turbines. Because the start-up emissions for the FB turbine are not available, staff has used the start up emissions data, provided by GE, for another facility with a similar configuration [three gas turbines, combined cycle with auxiliary boiler]. This facility uses three GE frame 7FA turbines and has guaranteed NO_x emissions of 9 ppm without the use of SCR (Appendix A). Because EAEC proposed turbines (7FB model) are larger, staff has linearly adjusted its start-up NO_x and VOC emissions upward to reflect the higher uncontrolled emissions of the FB model turbine.

For example, the GE-provided NO_x and VOC emissions for cold start up for the three-frame 7FA, combined cycle facility (at 9ppm) are 80 lbs and 67 lbs per hour, per turbine, respectively. Because the proposed FB model gas turbines have higher NOx emissions (25 ppm), staff adjusted the EAEC start-up NO_x and VOC emissions by a factor of 25 divided by 9, or 2.78. Thus the EAEC start up NO_x and VOC emissions would be 220 lbs and 180 lbs per hour per turbine, respectively, during the period of cold start.

Using the same approach, staff estimated that EAEC NO_x and VOC emissions during the period of hot start would be 200 lbs and 180 lbs per hour, respectively.

It should be noted that the applicant underestimated the times for cold start and hot start as well. According to GE, a start-up for a similar configuration facility (also equipped with auxiliary boiler) could last 4 hours for cold start, and 1.5 hours for hot start (Appendix A).

The staff and the applicant estimated daily and annual emissions from the project are shown in **AIR QUALITY Table 4**. The table shows different operating scenarios and the resultant emissions, including CTG startup (cold and hot), shutdown, and steady state operation.

AIR QUALITY Table 3
Power Train Hourly Emissions
(pound per hour [lb/hr] except where noted)

Staff estimated	**NO_x**	**SO_2**	**PM_{10}**	**VOC**	**CO**
Cold Start-up (total emissions for 4 hours)	2,640	N/A	N/A	2,160	3,350
Hot Start-up (total emissions for 90 minutes)	900	N/A	N/A	810	1,350
Applicant estimated					
Cold Start-up (total emissions for 3 hours)	720	N/A	N/A	48	2,514
Hot Start-up (total emissions for one hour)	240	N/A	N/A	16	902
Steady State @ 100% load[b]	71	22	55	20	104

AIR QUALITY Table 4
Project Daily and Annual Emissions

Operational Profile	**NO_x**	**SO_2**	**PM_{10}**	**VOC**	**CO**
3 turbine cold-start, hot start and steady state operation (maximum daily) (lbs/day)[1]	4,830	450	1,220	3,320	16,020
Maximum steady state daily operation (lbs/day)[2]	1,730	450	1,220	480	2,550
Maximum annual emissions including start ups and shutdown[1] (tons/year)	443	86	216	219	1,150

Notes:
[1] Staff estimated.
[2] EAEC, 2001a. AFC Table 8.1A-8.
[3] Assume 4 hr for each cold start, 1.5 hr for each hot start, 5100 hrs. steady state with duct burner and 3085 hrs. at steady state without duct burner.

In **AIR QUALITY Table 4**, staff has assumed 4-hours duration for each cold start, and 1.5-hours duration for each hot start. Staff also estimated the expected emissions using

the applicant's request of 50 cold starts and 250 hot start, 5100 hours steady state operation with duct burners, and the rest (3085 hours) steady state operation without the use of duct burners.

INITIAL COMMISSIONING

The initial commissioning refers to a period of approximately 60 days prior to beginning commercial operation when the combustion turbines will undergo initial test firing. During this commissioning phase, the project may operate at a low-load for a long period of time for fine-tuning. The District typically requires that each activity of the commissioning period be planned carefully, and that all NO_x and CO emissions and the time of commissioning be optimized to lessen the emissions from the turbines, duct burners and HRSG. It should also be noted that the NO_x and CO emissions during the commissioning period are not higher than emissions during normal start up of the facility; therefore, staff expects no new impact of the emissions during the commissioning period. All criteria air contaminant emissions during the commissioning period will be counted toward the annual emission limits; thus there is an incentive for the applicant to limit the commissioning period to the shortest time possible.

CLOSURE

Eventually the facility will close, either as a result of the end of its useful life, or through some unexpected situation, such as a natural disaster or catastrophic facility breakdown. When the facility closes, then all sources of air emissions will cease and thus all impacts associated with those emissions will no longer occur. The only other expected emissions will be fugitive particulate emissions from the dismantling activities. These activities will be short term and will create fugitive dust emissions levels much lower than those created during the construction of the project. Nevertheless, staff recommends that a facility closure plan be submitted to the Energy Commission Compliance Project Manager to demonstrate compliance with applicable District Rules and Regulations during closure activities.

AMMONIA EMISSIONS

Due to the large combustion turbines used in this project and the need to control NO_x emissions, significant amounts of ammonia will be injected into the flue gas stream as part of the SCR system. Not all of this ammonia will mix with the flue gases to reduce NO_x; a portion of the ammonia will pass through the SCR and will be emitted unaltered, out of the stacks. These ammonia emissions are known as ammonia slip. The applicant has committed to an ammonia slip no greater than 10 ppm (Calpine, 2001a). On a daily basis, a 10 ppm slip is equivalent to approximately 2,500 pounds of ammonia emitted into the atmosphere from the East Altamont Energy Center facility.

IMPACTS

Air dispersion models provide a means of predicting the location and magnitude of the air contaminant impacts of a new emissions source at ground level. These models consist of several complex series of mathematical equations, which are repeatedly calculated by a computer for many ambient conditions. The model results are often described as a unit of mass per volume of air, such as micrograms per cubic meter

($\mu g/m^3$). They are an estimate of the concentration of the pollutant emitted by the project that will occur at ground level.

The applicant has used an EPA-approved ISCST3 model to estimate the impacts of the project's NO_x, PM_{10}, CO and SO_x emissions resulting from project construction and operation. A description of the modeling analyses and results are provided in Section 8.1.5 and Appendices 8.1B and 8.1E of the AFC (Calpine, 2001a). The applicant's modeled impacts were added to the available highest ambient background concentrations measured during 1997 to 2000 at the Tracy or Livermore monitoring stations. Staff then compared the results with the ambient air quality standards for each respective air contaminant to determine whether the project's emission impacts would cause a new violation of the ambient air quality standards or contribute to an existing violation.

Inputs for the modeling include stack information (exhaust flow rate, temperature, and stack dimensions), specific turbine emission data and meteorological data, such as wind speed, atmospheric conditions, and site elevation. For this project, the meteorological data used as inputs to the model included hourly wind speeds and directions measured at the project site.

CONSTRUCTION IMPACTS

The applicant provided staff with a modeling analysis of the project's operating emissions impacts from directly emitted pollutants, which they believe demonstrates that no significant impacts will be caused by the construction of the project. Staff reviewed the applicant's modeling analysis and concludes that it is adequate.

The results of the project construction impacts analyses are presented in **AIR QUALITY Table 5**. The modeling analyses included both the fugitive dust and vehicle exhaust emissions, which include PM_{10}, NO_x and CO. In **AIR QUALITY Table 5**, the first and second columns list the air contaminant, i.e., NO_2, PM_{10}, and CO, and the averaging time for each air contaminant analyzed. The third and fourth columns present the project emission impacts and the highest measured concentration of the criteria air contaminants in the ambient air (background), respectively. The fifth column presents the total impact, i.e., the sum of project emission impact and background measured concentration. The sixth column presents the most restrictive ambient air quality standard for such air contaminant. The seventh column presents the percentage of the total impacts in relation to the most restrictive ambient air quality standards.

As indicated in **Air Quality Table 5**, the project construction activities would further exacerbate existing violations of the state 24-hour PM_{10} standard, and thus constitute a significant air quality impact for PM_{10}. The project's construction activities would not create a new violation of either NO_2 or CO air quality standards, thus those impacts are not considered significant.

Staff believes that the PM_{10} impacts from the construction of the project can be reduced with the implementation of the staff recommended construction mitigation measures, as discussed in the **Mitigation** section. However, some residual impacts are likely to remain, even after the construction mitigation measures are implemented.

AIR QUALITY Table 5
Facility Maximum Construction Impacts

Pollutants	Avg. Period	Impacts ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impacts ($\mu g/m^3$)	State Standards ($\mu g/m^3$)	Percent of Standard
NO_2	1-hr.	285	149	434	470	90
CO	8-hr.	152	3236	3386	10,000	35
PM_{10}	24-hr.	78	87	165	50	330

Source: EAEC, 2001a, AFC Table 8.1E-5.

OPERATION IMPACTS

The applicant provided staff with a modeling analysis of the project's operating emissions impacts from directly emitted pollutants, which they believe demonstrates that no violations of ambient air quality standards will be caused by the operation of the project. Staff reviewed the applicant's modeling analysis and concludes that it is adequate.

AIR QUALITY Table 6 presents the results of the modeling analysis using worst case hourly emissions, which include turbine start-up emissions as presented in **AIR QUALITY Table 4**. **AIR QUALITY Table 6** shows that, with the exception of PM_{10}, the project does not cause any new violations of any applicable air quality standard, and thus those impacts are not significant. As for PM_{10}, staff believes that the project itself will contribute to existing violations of the state 24-hour PM_{10} air quality standard. Therefore, the project's PM_{10} emission impacts are significant.

AIR QUALITY Table 6
Worst Case Facility Emission Impacts on Ambient Air Quality

Pollutants	Avg. Period	Impacts($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impacts ($\mu g/m^3$)	Most Restrictive Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1-hour	236	149	385	470[1]	80
	Annual	0.6	28	28.6	100[2]	30
SO_2	1-hour	20	40	60	650[1]	10
	24-hour	2	27	29	105[1]	10
CO	1-hour	690	5,940	6,630	23,000[1]	30
	8-hour	180	3,230	3,410	10,000[1]	35
PM_{10}	24-hour	7	87	93	50[1]	190
	Annual	0.6	23	23	30[1]	80

Notes: All short-term (1-hour) ambient air quality impacts have been modeled as the impacts dominated by the emergency generator or diesel fired pump emissions during periods of testing. All long-term (8-hour, 24 hour and annual) impacts are the impacts from the project caused by normal operations.

[1] State standards
[2] Federal standards

Source: EAEC, 2001a. Table 8.1-29.

CUMULATIVE IMPACTS

Staff's cumulative impact assessment is composed of two types of analyses. The first is an analysis of the project's directly emitted pollutants along with similar emissions from other foreseeable future projects that are currently under construction, or are currently under District review. The second is a discussion of the project's potential contribution to the formation of secondary pollutants, namely ozone and PM_{10}.

Directly Emitted Pollutant Impacts

To evaluate the direct emission impacts of the East Altamont Energy Center along with other probable future projects, staff needs specific information that is included when project applicants file an application with the District for a permit. Projects located up to six miles from the proposed facility usually need to be included in the analysis. Staff assumes that impacts from projects beyond six miles would not affect the modeling analysis on a cumulative basis. The District indicates that there is no source, which has received a permit to construct, which needs to be included in the cumulative impact analysis.

There are two other energy facilities [Tesla Power Plant by Midway Power, and Tracy Peaking Power Plant by GWF] proposed to be built and operated within six miles of the proposed project. In addition, a new town of approximately 10,000 acres is also proposed to be built adjacent to the proposed facility. Staff recommends that the applicant, Midway Power and GWF perform a cumulative impact analysis, which includes the emissions from East Altamont facility, the Tesla facility and Tracy Power facility and the expected emission impacts from the proposed new town adjacent to the proposed project property line. Staff expects to include the cumulative impact analysis results from the aforementioned sources in the Final Staff Assessment (FSA).

Secondary Pollutant Impacts

Ozone impacts

The proposed project's gaseous emissions, primarily NO_x and VOC, can contribute to the formation of ozone. There are air dispersion models that can be used to quantify ozone impacts, but they are only appropriate for use in regional air quality planning efforts where numerous sources are input into the model to determine the regional ozone impacts. There are no regulatory agency models approved for assessing single source ozone impacts. However, because of the known relationship of NO_x and VOC emissions to ozone formation, staff believes that the emissions of NO_x and VOC from the East Altamont facility have the potential to contribute to higher ozone levels if not mitigated. The project's NO_x and VOC contribution to the regional ozone problem is not considered to be significant if the applicant would provide emission reduction credits for NO_x and VOC, which are consistent with the District required offsets ratio.

Secondary PM_{10} impacts

The project's NO_x, VOC, NH3 and SO_x emissions can contribute to the formation of secondary PM_{10}, namely organics, nitrates, and sulfates.

Not all hydrocarbons can form secondary PM_{10}. Hydrocarbons with six or less carbon atoms in the chain will not participate in the formation of the carbon based PM_{10}. The

project's VOC emissions will be in the form of unburned natural gas, which contains only one to two carbon atoms in the chain. Thus, the turbine exhaust is not expected to emit any significant amount of VOC that can participate in the formation of secondary PM_{10}.

Concerning ammonium nitrate, staff believes that the project 's ammonia emissions have a potential to contribute to the ammonium nitrate emissions, which may worsen the violations of the state 24-hour PM_{10} standard. Available research (Spicer, 1982) indicates that the conversion of NO_x to nitrate is approximately between 10 to 30 percent per hour in a polluted urban area where ozone and ammonia are present in sufficient amount to participate in the reaction. Assuming a 30 percent NO_x to nitrate conversion rate and a linear extrapolation of the project's PM_{10} modeling results, staff has estimated that the maximum NO_x to nitrate impact from the project to be 4 $\mu g/m^3$. Because the area is non-attainment for the state 24-hr PM_{10} and possibly the federal 24-hour $PM_{2.5}$ standard, the ammonium nitrate contribution, although small, is significant without providing emission reductions as offsets. Staff believes that the ammonia slip from the turbine/HRSG exhausts should be reduced to 5 ppm (from the proposed 10 ppm) to lessen the contribution of ammonium nitrates to the local area.

Concerning sulfates as PM_{10}, staff believes that the project SO_2 emissions will contribute to sulfate levels in the area, although in a very small amount. Currently, there is no agency (EPA or CARB) recommended models or procedures for estimating sulfate formation. The applicant has conducted an analysis to quantify the potential for SO_2 to convert to particulate matter. This analysis is based on the ambient air quality conditions and the emissions in the San Joaquin Valley, which they believe represent the conditions at the project site. The results of this analysis indicate that up to 50 percent of the project's SO_2 emissions can potentially be converted to particulate matter [in the form of sulfates]. Similar analyses were performed in other siting cases in the Bay Area (Los Medanos, Delta) indicating that the potential conversion of SO_2 to particulate matter could be up to 35 percent.

Using a conservative 35 percent conversion of SO_2 to particulate matter, the project SO_2 emissions are expected to add an equivalent impact as much as 30 tons of particulate matter per year. Because the area is non-attainment for the state 24-hour PM_{10}, and possible non-attainment for the federal 24-hr $PM_{2.5}$ air quality standards, the project's SO_2 emissions can potentially contribute to the existing violations of the standards. Therefore, its SO_2 emissions contribution is significant. Staff believes that local offsets, in the form of emission reductions, should be provided to lessen the project's particulate matter contribution to the ambient air to a level of insignificance.

VISIBILITY IMPACTS

The applicant has provided, as part of their PSD application to the District, a visibility impact analysis, which shows that the project is not expected to exceed any significant visibility impairment increment inside any nearby (point Reyes National Seashore) PSD Class I areas (EAEC, 2001). Class I areas are areas of special national or regional value from a natural, scenic, recreational, or historic perspective. Staff has not received information from the District staff that the visibility impact analysis is adequate. Staff will address the result of the District's analysis in the FSA.

APPLICANT'S PROPOSED MITIGATION

CONSTRUCTION PHASE

The applicant proposes that it would implement Best Available Control Measures (BACM) during construction of the project. These measures are listed below:

- Frequent watering of unpaved roads and disturbed areas (at least twice a day).
- Limit speed of vehicles on the construction areas to no more than 10 MPH.
- Employ tire washing and gravel ramps prior to entering a public roadway to limit accumulated mud and dirt deposited on the roads.
- Treat the entrance roadways to the construction site with soil stabilization compounds.
- Place sandbags adjacent to roadways to prevent run-off to public roadways.
- Install windbreaks at the windward sides of construction areas prior to the soil being disturbed. The windbreaks shall remain in place until the soil is stabilized or permanently covered.
- Employ dust sweeping vehicles at least twice a day to sweep the public roadways that are used by construction and worker vehicles.
- Sweep newly paved roads at least twice weekly.
- Limit on equipment idle times (no more than five minutes).
- Employ electric motors for construction equipment when feasible.
- Apply covers or dust suppressants to soil storage piles and disturbed areas that remain inactive for over two weeks.
- Pre-wet the soil to be excavated during construction.
- Employ oxidizing soot filters on all large suitable off-road construction equipment with an engine rating of at least 100 bhp.
- Employ construction equipment that can be feasibly electrified to reduce their exhaust.

In addition, the applicant will maintain the construction emissions so that fugitive emissions will be limited by District rules to a maximum 20 percent opacity during any three-minute span. Because the construction emissions are short-term, the applicant has not proposed any emission reduction credits to offset the new emissions.

OPERATION PHASE

The applicant proposes to mitigate the emission increases from the proposed facility using a combination of clean fuel, emission control devices and emission reduction credits (EAEC, 2001a). The applicant proposes to use a combination of dry low-NO_x combustion design, Selective Catalytic Reduction and oxidation catalyst technology for each of the combined cycle turbine trains to minimize its NO_x, VOC and CO emissions. The proposed control devices are designed to maintain the turbine/duct burner

emissions to 2.5 ppm NO_x, 6 ppm CO, and 2 ppm VOC (EAEC, 2001a). The ammonia slip emissions (from unreacted ammonia in the SCR) are proposed to be maintained at 10 ppm or less. Natural gas will be the only fuel used, which will minimize the project's PM_{10} and SO_x emissions. Below is a brief description of the emission control technologies that East Altamont Energy Center will employ.

Dry Low- NO_x Combustors

Over the last 20 years, combustion turbine manufacturers have focused their attention on limiting the NO_x formed during combustion. Because of the expense and efficiency losses due to the use of steam or water injection in the combustor cans to reduce combustion temperatures and the formation of NO_x, CTG manufacturers are presently choosing to limit NO_x formation through the use of dry low- NO_x technologies. In this process, firing temperatures remain somewhat low, thus minimizing NO_x formation, while thermal efficiencies remain high.

Flue Gas Controls

To further reduce the emissions from the combustion turbines before they are exhausted into the atmosphere, flue gas controls, primarily catalyst systems, will be installed in the HRSG. The applicant is proposing two catalyst systems: a selective catalytic reduction system to reduce NO_x, and an oxidizing system to reduce CO and VOC.

Selective Catalytic Reduction

Selective catalytic reduction (SCR) refers to a process that chemically reduces NO_x by injecting ammonia into the flue gas stream, over a catalyst, in the presence of oxygen. The process is termed selective because the ammonia reducing agent preferentially reacts with NO_x rather than oxygen, producing inert nitrogen and water vapor. The performance and effectiveness of SCR systems are related to operating temperatures, which may vary with catalyst designs. Flue gas temperatures from a combustion turbine typically range from 950 to 1100°F.

Catalysts generally operate between 600 to 750°F (ARB 1992), and are normally placed inside the HRSG where the flue gas temperature has cooled. At temperatures lower than 600°F, the ammonia reaction rate may start to decline, resulting in increasing ammonia emissions, called ammonia slip. At temperatures above about 800°F, depending on the type of material used in the catalyst, damage to some catalysts can occur. The catalyst material most commonly used is titanium dioxide, but materials such as vanadium pentoxide, zeolite, or a noble metal are also used. These newer catalysts (versus the older alumina-based catalysts) are resistant to fuel sulfur fouling at temperatures below 770°F (EPRI 1990).

Regardless of the type of catalyst used, efficient conversion of NO_x to nitrogen and water vapor requires uniform mixing of ammonia into the exhaust gas stream. Also, the catalyst surface has to be large enough to ensure sufficient time for the reaction to take place.
The applicant proposes to use a combination of dry low-NO_x combustor and an SCR system to produce a maximum NO_x concentration exiting the HRSG stack of 2.5 ppm, corrected to 15 percent excess oxygen averaged over a 1-hour period.

Oxidizing Catalyst

To reduce the turbine CO and VOC emissions, the applicant proposes to install an oxidizing catalyst similar in concept to catalytic converters used in automobiles. The catalyst is usually coated with a rare metal, such as platinum, which will oxidize unburned hydrocarbons and CO to water vapor and carbon dioxide (CO2). The CO catalyst is proposed to limit the CO concentrations to 6 ppm at 15 percent O2.

OFFSETS

The proposed facility is required by the BAAQMD to provide offsets on an annual basis (tons per year (tpy)) for NO_x, VOC, and PM_{10} as shown in **AIR QUALITY Table 8**. The applicant has provided some emission reduction credits, in the form of District issued banking certificates, for 305 tpy of NOx, 42.5 tpy of VOC, and 2.2 tpy of PM_{10}. The applicant also proposes to provide 45 tpy of VOC emission reduction credit that they currently have under option agreement. In addition, the applicant proposed to pave a few entrance roads to some landfills, which they estimated that would generate approximately 210 tpy of PM_{10} emission reduction credits to offset the new PM_{10} emissions from the proposed project.

Staff has asked for, but the applicant has not provided, information about the location, and the method to achieve the emission reduction credits provided in the banking certificates. Without this information, staff will not be able to determine whether the proposed offset package is effective to mitigate the proposed project's emission impacts on the ambient air quality.

The applicant has not provided emission offsets for the new SO_2 emission increases from the proposed East Altamont Energy Center facility because the District has not required them to do so.

AIR QUALITY Table 8
Maximum Annual NO_2, VOC, and PM_{10} Emissions and Offsets

Pollutant	New Emissions (tpy)	Offset Ratio[1]	Offsets Required (tpy)	Proposed Offsets (tpy)
NO_2	443	1.15:1	510	***305*** (Calpine)
VOC	219	1:1	219	***42.5*** (Calpine) ***45*** (Option Contract)
PM_{10}	216	1:1	216	***2.3*** (Calpine) ***210*** (Road Paving)
SO_2	86	N/A	86	***0***

Notes: 1. Offset ratio as required by the BAAQMD.

ADEQUACY OF PROPOSED MITIGATION MEASURES

CONSTRUCTION PHASE MITIGATION

As mentioned earlier in the impact section, the construction of the project will cause PM_{10} emissions that will add to the existing violations of the ambient PM_{10} air quality standard. Therefore, the project PM_{10} emission impacts due to construction of the project are significant. Staff believes that the implementation of proposed specific mitigation measures during construction of the facility as identified in the Conditions of Certification will reduce, but not eliminate, the short-term impacts of PM_{10}. Thus, significant construction impacts from PM_{10} will remain.

OPERATIONAL PHASE MITIGATION

NO_x, VOC and Ozone

The proposed project will not cause a new, or contribute to any existing violations of any applicable NO_2 standard; therefore, the project's NO_2 emission impact is not significant.

NO_x and VOC are precursors to ozone. Thus, an increase in the emissions of these air contaminants will have a potential to contribute to the existing violations of the area's ozone air quality standard. As discussed in the **SETTING** Section, the area experienced violations of the state 1-hour ozone standard each and every year since 1992. In addition, there is no clear indication that the area will get better. The area also experiences violations of the federal 8-hour ozone air quality standard each and every year since 1992. Thus, it is of significant importance that any NO_x and VOC emission increases be fully offset to avoid worsening violations of the ozone ambient air quality standard.
The proposed project will add 443 tpy of NO_x and 219 tpy of VOC to the ambient air. The applicant has proposed to provide 305 tpy of NO_x and 87.4 tpy of VOC emission reduction credits as offsets. The proposed emission reduction credits amount to a shortfall of at least 138 tpy of NO_x [205 tpy with District's offset ratio requirement of 1.15 to 1] and 131.6 tpy of VOC emission reduction credits.

As discussed earlier, staff has no information about the location and the method to achieve the emission reduction credits that the applicant has proposed as offsets. Therefore, staff cannot determine whether the applicant's proposed offset package is adequate to mitigate the project's NO_x and VOC contribution to a level of less than significant.

PM_{10}

The applicant proposed to pave a few sections of roads of some landfills in Altamont, Milpitas and Petaluma to provide an estimate 205 TPY of emission reduction credits to offset the proposed project's emissions. Staff is concerned that the proposed PM_{10} offset package is not adequate because the sources, which provide the emission reductions as offsets, are located too far away from the project. The nearest source of emission reductions is located 14 miles away from the project site, and the other two sources are located approximately 30 and 60 miles away.

Staff attempted to determine the effectiveness of the applicant's proposed PM_{10} offset and believes that the emission reductions from the paving of roads will not be effective nor adequate to mitigate the project PM_{10} emission impacts to a level of less than significant. Staff conducted a screening modeling analysis to determine the impacts at the project site for each unpaved road at the applicant's proposed locations. For each road, the modeling analysis calculates a maximum impact, the location of the maximum impact and the expected impacts at the project site. A ratio of the impact at the project site and the maximum impact provides a reasonable expectation of the effectiveness of the offsets. As a result of this analysis, staff has determined that the emission reductions from road paving are only 2 percent effective from sources that are 14 miles away, only 1 percent effective from sources that are 30 miles away, and zero effectiveness from sources that are 60 miles away. These effectiveness values indicate that for every one hundred (100) tons of emission reductions that are 14 miles away, only 2 tons are actually mitigating the project emission impacts at the project site. The actual mitigation offset is reduced to 1 ton if the source is locating 30 miles away, and zero for a source that is 60 miles away.

Using the estimated effectiveness above, staff has determined that the applicant's proposed 205 tons of PM_{10} emission reductions has an equivalent effectiveness in mitigating the project's emission impacts of approximately 3 tons per year.

Staff has two other concerns regarding the applicant's proposed emission offsets. One is the need to revise the available emission reductions to reflect the actual moisture content of the dirt samples. Staff is also concerned that the road paving as mitigation is not effective in the winter months when the area experiences the worst PM_{10} violations, i.e., when the soil is wet after rain.

$PM_{2.5}$

The project's particulate matter emissions are mostly in the form of particles with diameters less than 2.5 μm ($PM_{2.5}$), while the emission reductions provided by the applicant are for particles with less than 10 μm in diameter (PM_{10}). Because $PM_{2.5}$ are particles that are most likely to reach deep into the lungs, they would be trapped for longer periods of time, sometimes permanently. Depending on the composition of the $PM_{2.5}$, i.e., if the particles are composed of any kind of toxic substance, the health effect can be very pronounced. In addition, since the area is non-attainment for the state's 24-hour PM_{10} and is likely to be non-attainment for the federal $PM_{2.5}$ 24-hour standard, emission offsets of both air contaminants will be necessary to mitigate the project's emission impacts.

Although PM_{10} contains $PM_{2.5}$, the $PM_{2.5}$ portion of the emission reductions from the paving of roads would be much less, i.e., approximately 10 to 30 percent of the total PM_{10}. Therefore, the applicant's proposed PM_{10} emission reductions would need to be adjusted for the $PM_{2.5}$ portion, which would result in much less available $PM_{2.5}$ emission reduction credits.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the minority population is less than fifty percent within a six-mile radius of the proposed East Altamont Energy Center facility, and Census 1990 information that shows the low-income population is less than fifty percent within the same radius. However, there is one census block that lies north and northeast of the proposed site, which contains more than fifty percent minority members. Staff will provide additional analysis in the Final Staff Assessment to verify whether a disproportional impact to the minority in the affected location can occur, and will recommend appropriate mitigation for the impacts.

RESPONSES TO PUBLIC COMMENTS

G&DK-9: *School bus route is on both Kelso and Mountain House Road bordering the plant. Students will be exposed to high volume of pollution on a daily basis.*

Response: Because of the close proximity with the facility, students are expected to be exposed to a certain level of air pollution during certain weather conditions. Based on the collected weather data, these conditions could happen approximately a few days per year. The applicant will be required to provide mitigation to the emissions increases from the proposed power plant, thus the short term exposure to these events can be reduced to a level of less than significant.

G&DK-14: *The project may affect the air quality in San Joaquin Valley. It is not clear what consideration has been given to the impacts on the air quality in the valley?*

Response: Staff is recommending that all emissions from the project be mitigated with emission reduction credits that not only meet the criteria of the District Air Quality rules, but would be effective to reduce the facility impacts to a level of less than significant, even in the San Joaquin Valley. These mitigation measures include NOx, VOC and local PM10 and SO2 emission reduction credits.

COMPLIANCE WITH LORS

FEDERAL

The applicant has submitted to the District an application for the federal PSD permit. The District has not issued a Preliminary Determination of Compliance (PDOC). Therefore, staff will provide discussions of the project's compliance with the federal PSD requirements in the FSA.
The applicant is also required to submit an application to the District for a Major Facility Review Permit (Title V) prior to commencing operation. The applicant is also restricted from commencing operation unless a Title IV Permit has been issued, or 24 months after submitting an acid rain application (Title IV) to the District, whichever is earlier. Compliance with both of these federal titles will be determined at a later date.

The EPA staff has provided comments to another energy facility (Morro Bay-00-AFC-12), which call for lower limits for NO_x (2 ppm), ammonia slip (5 ppm), and CO (2 ppm).

The EPA has made similar comments regarding a proposed cogeneration facility at the Miller Brewing Company in the South Coast Air Quality Management District, stating that the BACT analysis must start with a two ppm level for both NOx and CO. The applicant is aware of the EPA's comments and will respond to them if EPA makes similar comments in this case. Staff will work with the EPA staff to resolve these issues prior to the issuance of the staff FSA.

STATE

As discussed earlier and summarized below, the project has the potential to cause significant ozone and particulate matter impacts. Staff cannot conclude at this time that the project will be in compliance with state LORS.

LOCAL

The District has not issued a PDOC, thus staff will provide discussions of the project's compliance with the District's Rules and Regulations requirements in the FSA.

CONCLUSIONS

1. The project has the potential for not meeting the Federal PSD BACT requirement for NO_x, NH3 and CO emissions.

2. The project has the potential to cause significant impacts to the state 1-hour and the federal 8-hour ozone air quality standards.

3. The project has the potential to cause significant impacts to the state 24-hour PM_{10} and the federal 24-hour $PM_{2.5}$ air quality standards.

4. The proposed emission reduction credits are not adequate to mitigate the project's potential significant impacts to the state and the federal ozone, PM_{10} and $PM_{2.5}$ air quality standards.

RECOMMENDATIONS

Staff cannot recommend licensing the proposed East Altamont Energy Center unless the applicant provides sufficient evidence to demonstrate that the project will conform with all applicable air quality laws, and that emission reductions will be provided in sufficient quantities to mitigate the project's impacts to a level of less than significant. Below is a list of items to be provided or agreed upon by the applicant prior to issuing the staff Final Staff Assessment:

- Written or oral correspondence from EPA staff that the project's proposed emission limits will meet the federal BACT,
- Written correspondence from manufacturers of equipment and control devices to substantiate the proposed emissions of the project.
- An agreement to limit the ammonia slip from the SCR system to no more than 5 ppm to lessen the potential impacts of the project on the area PM_{10} and $PM_{2.5}$ ambient air quality standards.

- An agreement to provide additional emission reduction credits of 510 tpy of NO_x and 219 tpy of VOC to mitigate the project's significant contribution to the area's ozone air quality standards.
- An agreement to provide 216 tpy of local PM_{10} emissions reduction credits to mitigate the project's significant contribution to the area's PM_{10} air quality standard.
- An agreement to provide 86 tpy of SO_2 emission reductions to mitigate the project's significant contribution to the area's PM_{10} and $PM_{2.5}$ air quality standards.

CONDITIONS OF CERTIFICATION

PRECONSTRUCTION PHASE

AQ-1 The following amount of emission reduction credits shall be provided to, and approved by the District and the CPM for the following air contaminants:

NOx	=	509 tpy
VOC	=	252 tpy
PM10	=	219 tpy
SOx	=	86 tpy

Verification: At least thirty (30) days (or CPM approved timeframe) prior to issuance of the District's Authority to Construct, the project owner shall provide valid emission reduction credit banking certificates to the District and the CPM for approval.

AQ-2 The project owner shall seek Prevention of Significant Deterioration (PSD) Permit, Major Facility Review Permit (Title V), and Federal Acid Rain Permit (Title IV) from the District.

Verification: At least thirty (30) days (or CPM approved timeframe) prior to start construction, the project owner shall provide a copy of the required permits to the CPM.

AQ-3 The project owner shall provide to the CPM for approval all detailed specifications including scaled drawing, dimensions, operational characteristics, and emissions of each turbine, duct burner, auxiliary boiler, emergency generator, fire pump, and cooling tower.

Verification: At least sixty (60) days (or CPM approved timeframe) prior to start construction, the project owner shall provide all required information to the CPM for approval.

AQ-4 The project owner shall provide the District and the CPM all detailed specifications, including the location and configuration, of the stack sampling platforms and sampling ports to enable the performance of source testing.

Verification: At least thirty (30) days (or CPM approved timeframe) prior to start construction, the project owner shall provide for, and receive approval from the District and the CPM the configuration and location of the stack sampling platforms and ports.

AQ-5 The project owner shall provide to the District and the CPM the detailed specifications of the continuous emission monitoring system and a plan for collecting emission data, which demonstrate compliance with the Federal 40 CFR Part 75.

Verification: At least thirty (30) days (or CPM approved timeframe) prior to start construction, the project owner shall provide for and receive approval from the District and the CPM for the continuous emission monitoring system.

CONSTRUCTION PHASE

AQ-6 During construction of this facility, the following fugitive emission control measures shall be implemented at the plant site:

a. Suspend all land clearing, grading, earth moving, or excavation activities when winds (including instantaneous gusts) exceed 20 miles per hour.
b. Apply water to active construction sites and unpaved roads at least twice daily to control fugitive dust.
c. Apply sufficient water or dust suppressants to all material excavated, stockpiled, or graded to prevent fugitive dust from leaving the property boundaries and causing a public nuisance or a violation of an ambient air standard.
d. Apply a non-toxic solid stabilizer to all inactive construction areas (previously graded areas which remain inactive for 96 hours).
e. No on-site vehicle shall exceed a speed of 10 miles per hour on unpaved roads or areas.
f. All trucks hauling dirt, sand, soil, or other loose material will be watered or covered and will maintain at least two feet of freeboard to prevent a public nuisance.
g. Install wheel washers where vehicles enter and exit unpaved roads onto paved roads, or wash off trucks and any equipment leaving the site each trip.
h. Sweep streets with a water sweeper twice each day and more often if visible soil materials are carried onto adjacent public or private paved roads.
i. Re-establish ground cover on the construction site through seeding and watering as soon as possible, but no later than final occupancy.
j. Implement all dust control measures in a timely and effective manner during all phases of project development and construction.
k. Place sandbags adjacent to roadways to prevent run off to public roadways.
l. Install wind breaks at the windward sides of construction areas prior to the soil being disturbed. The wind breaks shall remain in place until the soil is stabilized or permanently covered.
m. Limit construction vehicles and equipment idle time to no more than 5 minutes.
n. Use of electricity to power, to the extent practical, construction equipment.

Verification: The project owner shall maintain a daily log of water truck activities, including records of the frequency of public road cleaning and area(s) that are covered or treated with dust suppressants. These logs and records shall be available for inspection by the CPM during the construction period. The project owner shall make the construction site available to the District staff and the CPM for inspection and monitoring. At least thirty (30) days (or CPM approved timeframe) prior to start of construction, the project owner shall provide to the CPM, for approval, a preliminary report showing the practicality of applying electrical power on construction equipment.

AQ-7 The project owner shall mitigate, to the extent practical, construction related emission impacts from off-road, diesel-fired construction equipment. Available measures which may be used to mitigate construction impacts include the following:

- Catalyzed Diesel Particulate Filters (CDPF);
- Ultra-Low-Sulfur Diesel fuel, with a sulfur content of 15 ppm or less (ULSD);
- Diesel engines certified to EPA and CARB 1996 or newer off-road equipment emission standards.

Verification: The use of each mitigation measure is to be determined in advance by a Construction Mitigation Manager (CMM), who will be available at the project site(s). The CMM must be approved by the CPM prior to the submission of any reports.

AQ-8 The Construction Mitigation Plan shall be submitted to the CPM for approval prior to rough grading on the project site, and must include the following:

1. A list of all diesel fueled, off-road, stationary or portable construction-related equipment to be used either on the project construction site or the construction sites of the related linear facilities. Equipment used less than a total of 10 consecutive days need not be included in this list.

2. Each piece of construction equipment listed under item (1) must demonstrate compliance with the following mitigation requirements:

Engine Size (BHP)	**1996 CARB or EPA Certified Engine**	**Required Mitigation**
< or =100	Yes or No	ULSD
>100	Yes	ULSD
>100	No	ULSD and CDPF, if suitable as determined by the CMM

3. If compliance can not be demonstrated as specified under item (2), then the project owner may appeal for relief to the CPM. However, the owner must demonstrate that they have made a good faith effort to comply as specified under item (2).

Verification: The project owner will submit to the CPM for approval the qualifications of the CMM at least 45 days (or CPM approved timeframe) prior to the due date for the Diesel Construction Equipment Mitigation Plan.

The project owner will submit the Diesel Construction Equipment Mitigation Plan to the CPM for approval 30 calendar days (or CPM approved timeframe) prior to rough grading on the project site or start of construction on any associated linear facilities.

AQ-9 Following the initiation of construction activities, and if changes to mitigation measures are necessary, the CMM shall submit a Report of Change and Mitigation Implementation to the CPM for approval. This report must contain at a minimum the cause of any deviation from the Construction Mitigation Plan, and verification of any Construction Mitigation Plan measures that were implemented.

The following is acceptable proof of compliance, other methods of proof of compliance must be approved by the CPM.

1. EPA or CARB 1996 off-road equipment emission standards:
2. A copy of the certificate from EPA or CARB.
3. Purchase and use of ultra-low-sulfur fuel (15 ppm or less).
4. Receipt or other documentation indicating type and amount of fuel purchased, from whom, where delivered and on what date; **and**
5. A copy of the text included in the contract agreement with all contractors and sub-contractors for use of the ultra-low-sulfur fuel in diesel burning construction equipment as identified in the Construction Mitigation Plan.
6. Installation of CDPF:
7. The suitability of the use of CDPFs is to be determined by a qualified mechanic or engineer who must submit a report to the CPM for approval.
8. Installation is to be verified by a qualified mechanic or engineer.
9. Construction equipment engine idle time:
10. A copy of the text included in the contract agreement with all contractors and sub-contractors to keep engine idle time to 10 minutes or less to the extent practical.

Verification: The project owner will submit the Report of Change and Mitigation Implementation to the CPM for approval no later than 10 working days (or CPM approved timeframe) following the use of the specific construction equipment on either the project site or the associated linear facilities.

AQ-10 If a specific mitigation measure is determined to be detrimental to a piece of construction equipment or is determined to be causing significant delays in the construction schedule of the project or the associated linear facilities, the mitigation measure may be terminated immediately. However, notification containing an explanation for the cause of the termination must be sent to the CPM for approval. All such causes are restricted to one of the following justifications and must be identified in any Report of Emergency Termination of Mitigation.

1. The measure is excessively reducing normal availability of the construction equipment due to increased downtime for maintenance, and/or power output due to an excessive increase in back pressure.
2. The measure is causing or is reasonably expected to cause significant engine damage.
3. The measure is causing or is reasonably expected to cause a significant risk to nearby workers or the public.
4. Any other seriously detrimental cause which has approval by the CPM prior to the change being implemented.

Verification: The project owner will submit a Report of Emergency Termination of Mitigation to the CPM for approval, as required, no later than 10 working days following the termination of the identified mitigation measure. The CPM will monitor the approval of all reports submitted by the project owner in consultation with CARB, limiting the review time for any one report to no more than 20 working days.

COMMISSIONING PHASE

AQ-11 The project owner shall minimize emissions of carbon monoxide and nitrogen oxides from gas turbines and heat recovery steam generators (HRSG) to the maximum extent possible during the commissioning period.

Verification: The owner/operator shall submit a monthly compliance report to the CPM. In this report the owner/operator shall indicate how this condition is being implemented.

AQ-12 At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the gas turbine combustors and HSRG's duct burners shall be tuned to minimize the emissions of carbon monoxide and nitrogen oxides.

Verification: The owner/operator shall submit a monthly compliance report to the CPM. In this report the owner/operator shall indicate how this condition is being implemented.

AQ-13 At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturers and the construction contractor, the SCR Systems and CO Oxidation Catalyst Systems shall be installed, adjusted, and operated to minimize the NOx, CO and VOC emissions from gas turbines/HSRG power trains.

Verification: The owner/operator shall submit a monthly compliance report to the CPM. In this report the owner/operator shall indicate how this condition is being implemented.

AQ-14 The project owner shall submit a plan describing the procedures to be followed during the commissioning of the gas turbines and HRSG to the District and the CPM prior to first firing of the gas turbines. 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 be limited to, the tuning of the Dry-Low-NO_x combustors, the installation and operation of the SCR systems and oxidation catalysts, the installation, calibration, and testing of the CO and NO_x continuous emission monitors, and any activities requiring the firing of the gas turbines and HRSG without abatement by their respective SCR and CO Catalyst Systems.

Verification: The owner/operator shall submit a monthly compliance report to the CPM. In this report the owner/operator shall indicate how this condition is being implemented.

AQ-15 The project owner shall demonstrate compliance with conditions 8 through 15, and conditions 19 through 24, through the use of properly operated and maintained continuous emission monitors and data recorders for the following parameters:
firing hours for each gas turbine and each HRSG
fuel flow rates to each gas turbine train
stack gas nitrogen oxide emission concentrations
stack gas carbon monoxide emission concentrations

stack gas carbon dioxide concentrations

The monitored parameters shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation) for the Gas Turbines and HRSG. The owner/operator shall use District-approved methods to calculate heat input rates, NO_x mass emission rates, carbon monoxide mass emission rates, and NO_x and CO emission concentrations, summarized for each clock hour and each calendar day. All records shall be retained on site for at least 5 years from the date of entry and made available to District personnel upon request.

Verification: The owner/operator shall submit a monthly compliance report to the CPM. In this report the owner/operator shall indicate how this condition is being implemented.

AQ-16 The District and CPM approved continuous emission monitors specified in condition AQ-5 shall be installed, calibrated, and operational prior to first firing of the gas turbines.

Verification: The owner/operator shall submit a monthly compliance report to the CPM. In this report the owner/operator shall indicate how this condition is being implemented.

AQ-17 Each gas turbine power train shall not operate more than 500 hours without abatement emissions by SCR System and/or Oxidation Catalyst System during the commissioning period. Upon completion of these activities, the project owner shall provide written notice to the District and the CPM, and the unused balance of the 500 firing hours without abatement shall expire.

Verification: The owner/operator shall submit a monthly compliance report to the CPM. In this report the owner/operator shall indicate how this condition is being implemented.

AQ-18 The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, PM_{10}, and sulfur dioxide that are emitted by the gas turbine/HRSG power trains during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in condition AQ-24.

Verification: The owner/operator shall submit a monthly compliance report to the CPM. In this report the owner/operator shall indicate how this condition is being implemented.

AQ-19 The combined facility emissions, including those during start-up and shut down events, shall not exceed the following limits during the commissioning period:

NO_x (as NO_2)	5,266 pounds per calendar day	400 pounds per hour
CO	16,272 pounds per calendar day	1,192 pounds per hour
POC (as CH_4)	686 pounds per calendar day	
PM_{10}	756 pounds per calendar day	
SO_2	82.5 pounds per calendar day	

Verification: The owner/operator shall submit a monthly compliance report to the CPM. In this report the owner/operator shall indicate how this condition is being implemented.

AQ-20 Prior to the end of the Commissioning Period, the project owner shall conduct a District and CPM approved source test using external continuous emission monitors to determine compliance with condition AQ-23. The source test shall determine NO_x, CO, and POC emissions during start-up and shutdown of the gas turbines. The POC emissions shall be analyzed for methane and ethane to account for the presence of unburned natural gas. The source test shall include a minimum of three start-up and three shutdown periods.

Verification: No later than twenty (20) working days before the commencement of the source tests, the project owner shall submit to the District and the CPM a detailed source test plan designed to satisfy the requirements of this condition. The District and the CPM will notify the project owner of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The project owner shall incorporate the District and CPM comments into the test plan. The project owner shall notify the District and the CPM within seven (7) working days prior to the planned source testing date. Source test results shall be submitted to the District and the CPM within thirty (30) days of the source testing date.

OPERATION PHASE

AQ-21 The gas turbines, duct burners, auxiliary boiler, and emergency generator shall be fired exclusively with natural gas.

Verification: The project owner shall maintain, on a monthly basis, a laboratory analysis showing the sulfur content of natural gas being burned at the facility. The monthly sulfur analysis shall be incorporated into the quarterly compliance reports as required in verification of Condition AQ-23.

AQ-22 Except during start up and shut down, the gas turbine/HRSG shall not be operated without the SCR and CO oxidation catalyst systems.

Verification: As part of the quarterly and annual compliance reports, as required by condition AQ-23, the owner/operator shall include information on the date, time, and duration of any violation of this permit condition.

AQ-23 Except during start-up and shut down, the gas turbine/HRSG emissions, including those at power augmentation and spinning reserve modes, shall not exceed the following limitations:

NOx	=	2 ppmvd at 15% excess oxygen based on hourly basis
VOC	=	2 ppmvd at 15% excess oxygen based on hourly basis
CO	=	2 ppmvd at 15% excess oxygen based on three-hours basis
NH3	=	5 ppmvd at 15% excess oxygen based on hourly basis.

Verification: The project owner shall submit to the District and CPM, quarterly reports for the preceding calendar quarter by January 30, April 30, July 30, and October 30, and an annual compliance report by January 30 for the preceding year. These reports shall include the following information. In addition, this

information shall be maintained on site for a minimum of five (5) years and shall be provided to District personnel on request.

a. Operating parameters of emission control equipment, including but not limited to ammonia injection rate, NO_x emission rate and ammonia slip.
b. Total plant operation time (hours), number of startups, hours in cold startup, hours in warm startup, hours in hot startup, and hours in shutdown.
c. Date and time of the beginning and end of each startup and shutdown period.
d. Average plant operation schedule (hours per day, days per week, weeks per year).
e. All continuous emissions data reduced and reported in accordance with the District approved CEMS protocol.
f. Maximum hourly, maximum daily, total quarterly, and total calendar year emissions of NO_x, CO, PM_{10}, VOC and SO_x (including calculation protocol).
g. Fuel sulfur content (monthly laboratory analyses, monthly natural gas sulfur content reports from the natural gas supplier(s), or the results of a custom fuel monitoring schedule approved by the District.
h. A log of all excess emissions, including the information regarding malfunctions/breakdowns.
i. Any permanent changes made in the plant process or production, which would affect air pollutant emissions, and indicate when changes were made.
j. Any maintenance to any air pollutant control system (recorded on an as-performed basis).

AQ-24 Except during start-up and shut down, the gas turbine/HRSG emissions, including those at power augmentation and spinning reserve modes, shall not exceed the following limitations:

NOx (as NO2)	=	23.8	lbs/hour
VOC	=	6.6	lbs/hour
CO	=	34.8	lbs/hour
PM10	=	18.3	lbs/hour
SO2	=	7.4	lbs/hour

Verification: The project owner shall submit to the District and CPM, quarterly reports for the preceding calendar quarter by January 30, April 30, July 30, and October 30, and an annual compliance report by January 30 for the preceding year.

AQ-25 Emissions of each turbine/HRSG power train shall not exceed the following limits for each start-up event

		Cold Start	Hot Start
NOx (as NO2)	=	880 lbs	300 lbs
VOC	=	720 lbs	270 lbs
CO	=	1,120 lbs	450 lbs

Verification: The project owner shall submit to the District and CPM, quarterly reports for the preceding calendar quarter by January 30, April 30, July 30, and October 30, and an annual compliance report by January 30 for the preceding year.

AQ-26 Except during start up and shut down, the auxiliary boiler emissions shall not exceed the following limits:

NOx (as NO2)	=	1.5 lbs/hour
VOC	=	0.6 lbs/hour
CO	=	5.0 lbs/hour
PM10	=	2.7 lbs/hour

Verification: The project owner shall submit to the District and CPM, quarterly reports for the preceding calendar quarter by January 30, April 30, July 30, and October 30, and an annual compliance report by January 30 for the preceding year.

AQ-27 The total facility emissions shall not exceed the following limits:

NOx (as NO2)	=	4,830	lbs/day
VOC	=	3,320	lbs/day
CO	=	16,020	lbs/day
PM10	=	1,220	lbs/day
SO2	=	450	lbs/day

Verification: The project owner shall submit to the District and CPM, quarterly reports for the preceding calendar quarter by January 30, April 30, July 30, and October 30, and an annual compliance report by January 30 for the preceding year.

AQ-28 The cumulative annual emissions from the facility, including those emissions during start-up, shut down, and power augmentation, shall not exceed the following limits:

NOx (as NO2)	=	443	tpy
VOC	=	219	tpy
CO	=	1,150	tpy
PM10	=	216	tpy
SO2	=	86	tpy

Verification: The project owner shall submit to the District and CPM, quarterly reports for the preceding calendar quarter by January 30, April 30, July 30, and October 30, and an annual compliance report by January 30 for the preceding year.

AQ-29 Each turbine/HRSG power train shall not be operated for more than 16 hours a day and more than 5,100 hours per year in power augmentation mode.

Verification: The project owner shall submit to the District and CPM, quarterly reports for the preceding calendar quarter by January 30, April 30, July 30, and October 30, and an annual compliance report by January 30 for the preceding year.

AQ-30 Auxiliary boiler shall not be operated for more than 8 hours per day and 3,000 hours per year.

Verification: The project owner shall submit to the District and CPM, quarterly reports for the preceding calendar quarter by January 30, April 30, July 30, and October 30, and an annual compliance report by January 30 for the preceding year.

AQ-31 Emergency generator shall not be operated, for test purposes, more than 1 hour per day and 200 hours per year.

Verification: The project owner shall submit to the District and CPM, quarterly reports for the preceding calendar quarter by January 30, April 30, July 30, and October 30, and an annual compliance report by January 30 for the preceding year.

AQ-32 Emergency fire engine shall not be operated, for test purposes, more than 1 hour per day and 100 hours per year.

Verification: The project owner shall submit to the District and CPM, quarterly reports for the preceding calendar quarter by January 30, April 30, July 30, and October 30, and an annual compliance report by January 30 for the preceding year.

AQ-33 The gas turbine/HRSG power trains shall not be in start-up mode simultaneously.

Verification: The project owner shall submit to the District and CPM, quarterly reports for the preceding calendar quarter by January 30, April 30, July 30, and October 30, and an annual compliance report by January 30 for the preceding year.

AQ-34 The project owner shall obtain approval from the District and the CPM, for all source test procedures to demonstrate compliance with conditions AQ-23 to AQ-28.

Verification: Within thirty (60) days of start-up of the facility, the project owner shall submit a testing plan of the facility to the District and CPM for approval. The plan shall include the acceptable test methods, procedures, and a range of operating conditions for each turbine/HRSG power train (70, 85 and 100 percent, with and without the operation of the duct burner). The tests shall include, as a minimum, water content, stack gas flow rate, oxygen content, NH3 slips, concentrations and mass emissions of NOx (as NO2), VOC (as methane), CO, SO2, and PM10 including condensable and sulfates.

Seven (7) days prior to the actual testing dates, the owner shall notify, in writing, the District and CPM the source test protocols and the projected testing dates.

Sixty (60) days after conducting the tests, the project owner shall provide the District and the CPM the results of the source tests.

APPENDIX A

GE provided start-up emissions data.

BIOLOGICAL RESOURCES

Andrea Erichsen

INTRODUCTION

This section provides the Energy Commission staff's analysis of potential impacts to biological resources from construction and operation of the East Altamont Energy Center (EAEC). The analysis focuses on impacts to state and federally listed species, fully protected species, species of special concern, wetlands, and other areas of critical biological concern. In this section, staff describes the biological resources of the project site and ancillary facilities; determines the need for mitigation; determines the adequacy of mitigation proposed by the applicant and, where necessary, specifies additional mitigation measures to reduce identified impacts to less than significant levels; determines compliance with applicable laws, ordinances, regulations, and standards; and recommends conditions of certification.

In order to determine the ecological significance of project impacts, staff relies primarily upon standards and criteria established by the Federal and State Endangered Species Acts, the California Environmental Quality Act (CEQA), and the Migratory Bird Treaty Act. Staff must determine significance based on whether populations of endangered, threatened, protected, and sensitive species or biotic communities will be adversely affected by the proposed EAEC. Significant impacts are those which affect a species' population size, geographic range, habitat, nesting success, and migration, or those which diminish, fragment, contaminate, or otherwise threaten biotic communities. The Fish and Game Code and other state and local regulations also help staff assess impacts. The above regulations direct applicants to avoid and mitigate for the loss of habitat for sensitive species and to obtain permits for incidental take of protected species.

This analysis is based upon information provided by the applicant in the Application for Certification (AFC), data adequacy information, data responses to data requests, as well as information gathered during site visits, data response workshops, and discussions with various agency representatives, including the U.S. Fish and Wildlife Service (USFWS), California Department of Fish and Game (CDFG), and the National Marine Fisheries Service (NMFS). This analysis is a joint environmental document with the Western Area Power Administration (Western), which is mandated to review the EAEC according to the National Environmental Policy Act (NEPA) because the EAEC proposes to connect to a Western facility (Western 2001a).

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

FEDERAL

Endangered Species Act of 1973

Title 16, United States Code, Section 1531 et seq., and Title 50, Code of Federal Regulations, part 17.1 et seq., designate and provide for protection of threatened and

endangered plant and animal species, and their critical habitat. Section 7 requires a permit from the U.S. Fish and Wildlife Service (USFWS) if “take” may result during lawful project activities. If no federal nexus exists for a project, a Section 10, Habitat Conservation Plan (HCP) may be required.

Migratory Bird Treaty Act

Title 16, United States Code, Sections 703 through 711, prohibits the take or possession of migratory birds, parts, or nests without a permit issued by the USFWS and California Department of Fish and Game (CDFG).

Bald and Golden Eagle Protection Act

Title 16, United States Code, Section 668, prohibits the take or possession of eagles, parts, or nests without a permit issued by the USFWS.

STATE

California Endangered Species Act of 1984

Fish and Game Code, sections 2050 through 2098, protects California’s rare, threatened, and endangered species.

California Code of Regulations

Title 14, California Code of Regulations, Sections 670.2 and 670.5, lists animals of California designated as threatened or endangered. The CEQA Guidelines Section 15000 et seq. defines the type and extent of biological information needed to evaluate impacts from a proposed project.

Title 20, California Code of Regulations, Section 1702 protects “areas of critical concern” and “species of special concern”.

Fully Protected Species

Fish and Game Code Sections 3511, 4700, 5050, and 5515, prohibits take of plants and animals that are fully protected in California.

Significant Natural Areas

Fish and Game Code Section 1930 designates certain areas such as refuges, natural sloughs, riparian areas and vernal pools as significant wildlife habitat.

Fish and Game Code Section 1580 designates land and water areas as significant wildlife habitats so they can be preserved in natural condition for low impact public use.

Streambed Alteration Agreement

Fish and Game Code Section 1600 reviews project impacts to waterways, including impacts to vegetation and wildlife from sediment, diversions and other disturbances.

Native Plant Protection Act of 1977

Fish and Game Code Section 1900 et seq., designates state rare, threatened, and endangered plants.

LOCAL

Alameda County East County Area Plan (1994)

- Policy 113 requires landscaping which enhances the scenic quality of an area. Criteria for landscaping includes: use of drought resistant plants, use of plants compatible with the surrounding vegetation, use of plants which provide habitat value, use of plants which are fire retardant, and suitable to site conditions.

- Program 51 provides a list of extremely invasive non-native plants that are not suitable for landscaping.

- Policy 118 states that the county will secure open space, through acquisition of easements or fee title, for the specific purpose of preserving wildlife habitats.

- Policies 119-120 encourage preservation and enhancement of biological diversity and provide specific attention to management of special status species.

ENVIRONMENTAL SETTING

REGIONAL SETTING

The East Altamont Energy Center (EAEC) is located within a 174-acre parcel of agricultural land in the eastern corner of Alameda County, along the western side of the San Joaquin Valley. The Clifton Court Forebay is a prominent waterbody, which is located to the north of the EAEC site and connects with the Delta-Mendota Canal and California Aqueduct. The project site lies northeast of the intersection of Mountain House Road and Kelso Road, and lies east of the Tracy Pumping Station (which is on the Delta-Mendota Canal) and approximately 8 miles northwest of the city of Tracy. Western owns the Tracy substation located less than 0.5 miles southwest of the EAEC site and there are a few other small “industrial” land uses within 5 miles of the EAEC site.

The project area, elevation 40 feet above mean sea level, is located along the eastern edge of the Altamont Hills and along the western edge the San Joaquin Valley. The Altamont Hills and surrounding mountain ranges provide important habitats for a diversity of species. In addition, the agricultural landscape of the San Joaquin Valley also provides open space, foraging, denning, and nesting habitats for wildlife. The agricultural products of the area include: alfalfa fields, hay, row crops, orchards, annual grasslands, cattle pasture, and dairies (EAEC 2001a, page 8.2-2).

General habitats potentially affected by the proposed EAEC include annual grassland, alkaline meadows, emergent marsh, and riparian shrub, as well as agricultural crops and irrigation ditches. The loss of natural and agricultural lands to housing and industrial uses has accelerated in recent years and it has become increasingly important to protect open space and habitats in the region.

LOCAL SETTING

Agricultural crops dominate the EAEC project site, while the surrounding areas are characterized by increasing levels of urban development. The proposed power plant and associated facilities will require 40 acres within the 174-acre project site (EAEC Supplement B, received October 10, 2001). The EAEC project site is rectangular, bordered by irrigation ditches along the eastern and southern boundaries. The ditch along the east side provides a corridor less than 5 feet wide of wetland vegetation. Until recently, the parcel was used for agriculture, particularly crops such as alfalfa, which can be beneficial to wildlife (EAEC 2001a, Figure 8.2-1). The project site is also surrounded on three sides by paved 2-lane highways. A small residential area is located on adjacent lands to the south. In general, the vegetative communities on the project site are classified as agricultural and/or ruderal, and the endemic natural plant and animal communities have been permanently altered, reduced, fragmented, and/or extirpated over the past decades.

Sensitive Local Habitats

Despite the highly modified character of the local landscape and natural communities, the agricultural habitats and small riparian corridors still provide important habitats for the dispersal, refuge, nesting, and foraging of a diversity of wildlife and plant species. Sensitive and rare natural communities such as those discussed below exist in the EAEC project area.

Wetlands are sensitive habitats characterized by many uniquely-adapted plant and animal communities. Federal and state laws provide special protection for wetlands because of their rarity and historic losses resulting from draining and filling, and because they provide a variety of valuable ecosystem benefits such as groundwater recharge, flood buffering, soil retention, and wildlife habitat. Wetlands are classified according to their soils, hydrology, and associated plant species. Emergent freshwater marshes and vernal pools are wetland habitats, that are present to the south and east of the project site. These areas will be avoided by the EAEC (EAEC 2001a, page 8.2-3). If there are wetlands that cannot be avoided, specific permits would be required from the CDFG and Army Corps of Engineers (ACOE) (EAEC 2001u, pp.12-14).

Vernal pool communities are rare and are characterized by assemblages of co-evolved plants and animals (Ericksen and Belk 1999; Thorne 1984; USFWS 1994; USFWS 1996). Vernal pools are seasonally flooded depressions found on ancient soils with an impermeable layer such as a hardpan, claypan, or volcanic basalt (Holland and Jain 1988). In California, vernal pool communities have come under increasing pressures from human conversion of lands for urban uses (USFWS 1994; USFWS 1996). Endemic to vernal pools are many plants and animals such as fairy shrimp. There are 25 species of fairy shrimp in California, five of which have special status as threatened or endangered largely due to habitat destruction (Ericksen and Belk 1999). The low-growing and sparse plant cover common around vernal pools is attractive hunting and breeding habitats for many species of wildlife, including the San Joaquin kit fox and burrowing owl. Vernal pool habitats are found in the project region but are not found on the EAEC project site. For example, a large area of alkaline meadow habitat occurs northeast of the intersection of Bruns and Kelso roads, approximately 1 mile west of the

project site (EAEC 2001a, Figure 8.2-1 and Figure 8.9-1). The EAEC proposal states this area will be avoided completely.

Designated Core Habitat for the California red-legged frog exists less than 5 miles south and southwest of the EAEC project site (USFWS 2000). This area is protected and will be avoided by direct impacts of the EAEC. However, careful attention must be made to avoid indirect and cumulative impacts caused by water use, degradation of connected riparian areas and drainages, and general habitat fragmentation in the area which may impact the local population.

Riparian habitats provide nesting, hunting, and roosting areas for diverse animal species and provide habitat for native plants. It is estimated that at least 90% of California's original riparian habitat has been removed and/or degraded by human activities, thus underscoring the importance of protecting and/or restoring remaining riparian habitats (Warner 1984). This particular habitat does not occur on the EAEC project site, but is present in the area. The EAEC project region contains riparian communities to the south, west, and east of the project site; a small area (0.2 acre) of willows, oaks, and non-native giant cane *(Arundo donax*) exists where Mountain House Creek crosses Byron Bethany Road from southwest to northeast. This habitat would have been affected by construction of the recycled water pipelines (4a & 4b). However, the recycled water pipelines have been eliminated from the CEC review process because the recycled water supply form the community of Mountain House is too speculative (refer to **Soil and Water** section of this Staff Assessment). It is expected that impacts to riparian habitats will be avoided or minimized by the EAEC.

EAEC Project Site Vegetation

The EAEC project site has been used for agriculture for many years and is flat and well-drained with ditches and subterranean tiles to collect return water flow. No natural drainages or ponds exist on the EAEC project site.

Site vegetation was fallow and tilled when Biology staff visited the site (in May and August), but the site has recently been used to cultivate oat-hay in the northern half, and alfalfa, tomatoes, or lima beans in the southern half (EAEC 2001a, page 8.2-2). The edges of the parcel support linear patches of weeds and ruderal grassland such as: slender oat grass *(Avena barbata*), knotweed *(Polygonum arenastrum*), common chickweed *(Stellaria media*), scarlet pimpernel *(Anagallis arvensis*), and fiddleneck *(Amsinckia menziesii var. intermedia*). Annual grassland is common in the area and is characterized by exotic grasses such as brome *(Bromus diandrus, B. hordeaceous),* oats *(Avena fatua*), and barley *(Hordeum murinum*). Common forbs include exotic species such as storksbill *(Erodium cicutarium*), wild radish *(Raphanus sativa*), and mustard *(Brassica nigra*) (EAEC 2001a, page 8.2-2). Annual grassland and ruderal vegetation are also widely distributed along roadways and the uncultivated areas immediately adjacent to an irrigation ditch running along the east side of the project site. In addition, the irrigation ditches along the eastern boundary contain no woody vegetation or emergent vegetation but they do contain burrows which may be inhabited by San Joaquin kit fox or burrowing owl (discussed below). Irrigation ditches, streams, ponds, and wetlands occur adjacent to alternative linear routes for water and gas pipelines. The most frequently observed plant species include: narrowleaf plantain *(Plantago lanceolata*), rabbitsfoot grass *(Polypogon monspeliensis*), sour clover

(*Melilotus indica*), prickly sow thistle (*Sonchus asper*), perennial ryegrass (*Lolium perenne*), Italian ryegrass (*L. multiflorum*), alkali mallow (*Malva leprosa*), ripgut brome, willow herb (*Epilobium ciliatum*), and tall flatsedge (*Cyperus eragrostis*).

Wildlife in the Project Area

Agricultural and ruderal vegetation provides habitat for both common and rare wildlife populations. For example, a sample of common wildlife species may include: California ground squirrel (*Spermophilus beecheyi*), California vole (*Microtus californicus*), coyote (*Canis latrans*), raccoon (*Procyon lotor*), opossum (Didelphis virginiana), striped skunk (*Mephitis mephitis*), badger (*Taxidea taxus*), red-tailed hawk (*Buteo jamaicensis*), northern harrier (*Circus cyaneus*), American kestrel (*Falco sparverius*), white-tailed kite (*Elanus leucurus*), great-horned owl (*Bubo virginianus*), barn owl (*Tyto alba*), turkey vulture (*Cathartes aura*), American killdeer (*Charadrius vociferus*), long-billed curlew (*Numenius americanus*), gopher snake (*Pituophis melanoleucus*), garter snake (*Thamnophis* species), and western fence lizard (*Sceloporus occidentalis*), as well as many native insect species. There are also several bat species, which are nocturnal mammals. Bats in the area feed on insects over agricultural and natural areas, and are state species of special concern. Locally common and abundant wildlife species are important components of the ecosystem. Many of these species have adapted to using agricultural, ruderal, and ornamental vegetation for cover, foraging, dispersal, and nesting.

Special Status Species

The EAEC site is also historically and currently inhabited by several sensitive species with special status under federal and state laws. **Biological Resources Table 1** contains the applicant's summary of special species that may potentially occur on-site and be adversely impacted by EAEC construction, operation, and maintenance (EAEC 2001a, pages 8.2-4 to .2-14).

Fourteen special-status plant species listed in **Biological Resources Table 1** potentially occur within the vicinity of the project site. However, special-status plants were not identified on the 174-acre site. Long-term human management for intensive agriculture (ditch maintenance, use of concrete and herbicides) has eliminated many of the environmental conditions required for survival by these special-status plant species. There is the potential for some residual alkali sink species on-site or nearby (EAEC 2001a, Table 8.2-1A).

The CDFG has identified potential for the presence of sensitive species and natural communities not mentioned in the AFC (CDFG 2001a, page 2). These include:

- Loggerhead shrike (*Lanius ludovicianus*)
- Golden eagle (*Aquila chrysaetos*)
- Vernal pool fairy shrimp (*Branchinecta lynchii*)
- Rose mallow (*Hibiscus lasiocarpus)*
- Mason's lilaeopsis (*Lilaeopsis masonii*
- Valley sink scrub plant community

These species and communities should be surveyed for and protected if nests, individuals, or habitats are found in areas impacted by EAEC facilities or linears.

Biological Resources Table 1
Sensitive Species Occurring In the EAEC Project Area
(Source: EAEC 2001a, Table 8.2-1A; CDFG 2001a)

Common Name	Scientific Name	Status
Plants		
Alkali milkvetch	*Astragalus tener var. tener*	FSC/ 1B
Ferris' milkvetch	*Astragalus tener var ferrisiae*	FSC/ 1B
Heartscale	*Atriplex cordulata*	FSC/ 1B
San Joaquin saltbrush	*Atriplex joaquiniana*	FSC/ 1B
Brittlescale	*Atriplex depressa*	--/ 1B
Big tarplant	*Blepharizonia plumose*	--/ 1B
Hispid bird's-beak	*Cordylanthus mollis ssp. Hispidus*	FE/SCE/ 1B
Palmate- bracted bird's- beak	*Cordylanthus palmatus*	SC/ 1B
Recurved larkspur	*Delphinium recurvatum*	SC/ 1B
Diamond-petaled Calif.poppy	*Eschscholzia rhombipetala*	FSC/ 1A
Showy madia	*Madia radiata*	--/ 1B
Showy Indian clover	*Trifolium amoenum*	FE/ 1B
Rayless ragwort	*Senecio aphanactis*	--/ 2
Caper- fruited tropidocarpum	*Tropidocarpum capparideum*	FSC/ 1A
Rose mallow	*Hibiscus lasiocarpus*	-/SSC
Mason's lilaeopsis	*Lilaeopsis masonii*	-/SSC
Insects and Crustacea		
Vernal Pool Fairy Shrimp	Branchinecta lynchi	FT/-
Mammals		
San Joaquin pocket mouse	*Perognathus inornatus inornatus*	SC/--
San Joaquin kit fox	*Vulpes macrotis mutica*	FE/--
Reptiles and Amphibians		
California red-legged frog	*Rana aurora draytonii*	FT/--
Western pond turtle	*Clemmys marmorata*	FSC/SSC
California tiger salamander	*Ambystoma californiense*	FC/ SSC
Birdss		
Golden eagle	*Aquila chrysaetos*	SFP/SSC
White-tailed kite	*Elanus leucurus*	-/ SFP
Swainson's hawk	*Buteo swainsoni*	-/ ST
Burrowing owl	*Athene cunicularia*	FSC/ SSC
Short-eared owl	*Asio flammeus*	-/SSC
Northern harrier	*Circus cyanneus*	-/SSC
Loggerhead shrike	*Lanius ludovicianus*	-/SSC
California horned lark	*Eremophila alpestris actia*	-/SSC
Tricolored blackbird	*Agelaius tricolor*	FSC/SSC
Mountain plover	*Charadrius montanus*	FC/SC

NOTES: FE = Federally listed as endangered. FT = Federally listed as threatened. FPE = Proposed endangered. FPT = Proposed threatened. FC = Candidate for listing as federal threatened or endangered. Proposed rules have not yet been issued because they have been precluded at present by other listing activity. FSC = Species of Special Concern threatened. SE = Species whose continued existence in California is jeopardized. ST = Species that although not presently threatened in California with extinction, is likely to become endangered in the foreseeable future. SC=State candidate for listing as threatened or endangered. SSC = California Department of Fish and Game Species of Special Concern (species with declining populations in California). SFP = Fully protected against take pursuant to the Fish and Game Code Section 3503.5. -- = No California or federal status. CNPS = California Native Plant Society Listing (does not apply to wildlife species). 1A = Plants presumed extinct in California. 1B = Plants, rare, threatened or endangered in California and elsewhere and are rare throughout their range. According to CNPS, all of the plants constituting List 1B meet the definitions of Sec. 1901, Chapter 10 (Native Plant Protection) of the California Department of Fish and Game Code and are eligible for state listing .

PROJECT SPECIFIC IMPACTS

Permanent and temporary impacts of the EAEC are summarized in **Biological Resources Table 2.** The applicant submitted revised quantities for habitat acres to be impacted by the revised project on October 10, 2001. **Biological Resources Table 2** reflects the most recently submitted information (EAEC 2001v, page 3).

The EAEC will result in the permanent removal of approximately 40 acres of prime agricultural land and wildlife habitat. The construction laydown area, natural gas, water supply pipelines, and transmission lines will also result in temporary habitat losses, that may impact special status species (EAEC 2001a, pages 8.2-17, 8.2-18, 8.2-28; EAEC 2001u, pages 10-11). None of the special status species listed in **Biological Resources Table 1** were detected visually or otherwise during biological surveys of the project area. However, there is potential for the special status species to occur within the project site because the EAEC property and vicinity provides foraging and dispersal habitats in an area that has become increasingly fragmented by human development (Gan 2001; Gan 2001a; Larson 2001). The USFWS directed the applicant to assume local presence of listed species such as San Joaquin kit fox. Thus, habitat mitigation for permanent and temporary impacts to plant and animal species will be required, and management of the mitigation land must be conducted with specific goals for enhancing and protecting special status plant and animal populations (EAEC 2001, page 8.2-18).

BIOLOGICAL RESOURCES Table 2
Acreage Impacts

	Permanent Impacts (acres)	Temporary Impacts (acres)*
Power plant footprint	40	0
Construction Access road and visual Screening	2	0
Construction laydown areas	0	20
Transmission tower footprints	0.5	0.5
Transmission line	N/A	N/A
Raw water pipeline (Route 3A)	0	23.63
Raw water pipeline (Route 3B)	0	32.72
Raw water pipeline (Route 3D)	0	21.81
Raw water pipeline (Route 3E)**	0	19.09
Water supply pump at Canal 45	0.2	0
Natural gas pipeline (preferred route 2A)	0.1	12.7
Total***	42.8	52.29

Source: EAEC 2001a, Table 8.2-2, page 8.2-17; EAEC 2001v, page 3)
*All pipeline acreages were converted from linear distances into acres assuming a 75 ft. wide buffer.
**Applicant's preferred route
***Total assuming selection of Rout 3E

Impacts to Special Status Plants

Through removal of habitat, the EAEC may impact the following special status plant species, which historically occurred in the project area (EAEC 2001a, Table 8.2-1B):

- Alkali milkvetch
- Ferris' milkvetch
- Heartscale
- San Joaquin saltbrush
- Brittlescale
- Big tarplant
- Hispid bird's-beak
- Palmate- bracted bird's- beak
- Recurved larkspur
- Diamond-petaled California poppy
- Showy madia
- Showy Indian clover
- Rayless ragwort
- Caper- fruited tropidocarpum (thought to be extinct)

The project site has been heavily disturbed and cultivated over many decades, and is too small to be characterized as a functional and sizable patch of habitat for populations of many of the above plant species. However, the project site lies close to natural areas where these species may persist. For example, many of the sensitive plant species listed in **Biological Resources Table 1** are endemic to the vernal pool habitats or wetlands which are located south and west of the EAEC site, near the corner of Kelso and Bruns roads. Thus, impacts to these habitats and species must be avoided.

The project linears potentially traverse a variety of habitats, including disturbed annual grassland, agriculture, industrial and urban, alkaline meadows, and riparian shrub communities. Some plants such as big tarplant and showy Indian clover may grow along grassland portions of project linear features. The applicant conducted plant surveys on-site and along proposed linears, which confirmed that agricultural and ruderal plant species predominate in the area. The applicant agreed to conduct additional surveys for tarplant (EAEC 2001p, data response 46).

The plant species in **Biological Resources Table 1** have not been recorded on-site, and although they may be able to grow in the area, it is unlikely that any populations potentially persisting in the area will be significantly impacted by the EAEC.
The applicant will be required to conduct pre-construction surveys to ensure that habitats crossed by project linears do not contain intact native habitat or sensitive plant species. If such species are found, the applicant will be required to avoid the plants, or to relocate them and establish restoration and mitigation for the species impacted.

Impacts to Special Status Animals

There are several special status species that are assumed to be present in the area and thus could potentially inhabit the EAEC vicinity (CDFG 2001a; Gan 2001; Larson 2001). For example, the EAEC vicinity and project site provide habitats suitable to support use by San Joaquin kit fox, red-legged frog, California tiger salamander, Swainson's hawk,

burrowing owl, and other protected wildlife. The potential impacts to wildlife species of concern are discussed in the section below.

As a preface to the following sections, the loss of permanent and temporary habitat acreage for special status species is significant and must be mitigated with a habitat compensation package (CDFG 2001a; Gan 2001; Larson 2001) (see **BIO-9**). In particular, San Joaquin kit fox, Swainson's hawk and seven proposed candidate, protected, or species of concern may occur on the project site and along project linears and thus, their populations would be significantly adversely impacted by the EAEC (see also section on **Cumulative Impacts**) .

Mitigation for impacts to special status species will be contained in the Biological Opinion issued by the USFWS as part of the Section 7 process of the Federal Endangered Species Act. Actions that will directly remove habitat for these species, must be mitigated with off-site, local mitigation. On-site mitigation using the lands surrounding the power plant, will be protected and managed to provide foraging habitat for wildlife and to protect agricultural land. The acreage required for off-site mitigation will be finalized in the FSA after continued consultation with the USFWS, CDFG, and Western. The CDFG streambed alteration permit and Determination of Consistency will also be required for listed species (See **BIO-5** and **BIO-6**).

In general, in recognition of significant impacts to all sensitive species discussed below, the EAEC has stipulated that they will:

1) avoid sensitive habitats in designing on-site facilities and linears;
2) conduct pre-construction surveys; and
3) minimize the impacts of construction, operation, and maintenance to the sensitive and special status species in the area.

(see Conditions of Certification **BIO-4, BIO-5, BIO-6, BIO-7, BIO-8, and BIO-9**).

San Joaquin kit fox *(Vulpes macrotis mutic*a): This species is federally endangered and state threatened. The San Joaquin kit fox is a largely nocturnal species, which prefers open grassland habitats. Kit foxes hunt small mammals, insects, reptiles, and birds and dig dens in sandy, loose-textured, loamy soils (Morrell 1972; USFWS 1983; Zeiner et al. 1990). Due to habitat loss within its historic range, this small fox must use agricultural fields and associated landscape features such as ditches and roadsides for denning and hunting (USFWS 1983; Zeiner et al. 1990). Mortality from automobiles, shootings, and poisonings is problematic in agricultural areas. San Joaquin kit fox use dens year-round, typically creating many entrances, and they rotate between many different dens within a geographic area over time (USFWS 1983; Zeiner et al. 1990). Thus, kit fox require an ample supply of suitable den sites and every den should be considered important (CDFG 2001a; Gan 2001; Larson 2001; USFWS 1983). Natural spatial and temporal changes in den use for breeding and overwintering must be considered and all dens must be protected (Larson 2001; Zeiner et al. 1990).

The EAEC project area represents an important, and increasingly at-risk, portion of the northern habitat range for the San Joaquin kit fox, whose historic range extended throughout San Joaquin Valley and parts of Alameda and Contra Costa counties (Gan 2001; Larson 2001; Wheslar 1992). Land conversion in the San Joaquin Valley, from

uncultivated natural habitat to urban development and agriculture, is a significant causal factor in this species' decline to a level considered endangered (Morrell 1975; O'Farrell 1983; USFWS 1983; Weslar 1992; Zeiner et al. 1990).

Habitat loss in the EAEC project area is accelerating. For example, the approval of the new town of Mountain House will remove thousands of acres to the east and south of the EAEC project site. The EAEC will remove approximately 40 acres of this habitat directly and may result in indirect impacts to habitat quality. Indirect impacts include increased traffic and construction disturbances, as well as increased fragmentation of the remaining habitat. In 1987, there were approximately eight kit foxes inhabiting the region around Bethany Reservoir, which lies less than 2 miles southwest of the EAEC project site (EAEC 2001a page 1-2; Figure 8.2-2).

Today, there are few kit fox in the area, although the Byron-Bethany hills are theorized to support up to 25 pairs (Gan 2001a). The EAEC project area constitutes important open space in terms of providing habitat for the dispersal, cover, foraging, and denning of this species (Gan 2001; Larson 2001; Zeiner et al. 1990). Acknowledging this, the EAEC reached an agreement with USFWS to not conduct protocol level surveys, but rather to assume presence of this species (EAEC 2001r, page 1; Larson 2001). The project linears follow road berms, rights-of-way, and levees that may be suitable for kit fox dens. To minimize the potential for adverse impact to kit foxes, the applicant will implement pre-design surveys of the linears to identify the presence of any burrows or dens so that avoidance measures can be planned. Impacts to San Joaquin kit fox will be mitigated through the Section 7 consultation with the USFWS with Western acting as the lead agency.

California red-legged frog *(Rana aurora draytonii*): This is a federally threatened species that breeds in ponds and still waters in the coastal foothills and agricultural areas in the project area (Zeiner et al. 1988). The Core California red-legged frog habitat, as designated by USFWS, lies several miles west of the project site and project linears, in the coastal foothills (Larson 2001). The species has also been reported from several locations within 1 mile of the project site and may disperse through the project site, although the likelihood of this is low due to road mortality as well as existing human-modified habitat quality. However, project linears cross and run parallel to small waterways (including Mountain House Creek, Canal 45, the Delta-Mendota Canal) and farm ponds that are potential habitat for red-legged frogs (EAEC 2001a, pages 8.2-6 and 8.2-7).

The applicant conducted a reconnaissance and spotlight survey on January 18, 2001 (EAEC 2001 Appendix 8.2E). The survey did not detect red-legged frogs and determined that most farm ponds and the majority of Canal 45 were dry and unsuitable habitat. Mountain House Creek was dry at the point where it crosses Byron Bethany Road, and therefore these areas are not suitable perennial habitat for the frog. Natural drainages near the corner of Kelso and Bruns roads contained water as did several agricultural ditches and ponds. Thus, the EAEC would have a low potential to significantly affect the California red-legged frog. However, because the frog is a listed species, any potential impact may be deemed significant and the Section 7 consultation through the USFWS will cover this species as well. Avoidance of wetland habitat

combined with habitat mitigation will effectively reduce adverse impacts to an insignificant level.

California tiger salamander (*Ambystoma californiense)*: The tiger salamander is a federal candidate species and a state species of special concern (Federal Register 2001; vol. 66, page 54818). On July 6, 2001, the CDFG received a petition to list the tiger salamander as an endangered species (California Regulatory Notice Register 2001, vol. 33-Z, page 1393). This salamander breeds in vernal pools and ponds, and summers in animal burrows or soil crevices (Zeiner et al. 1988). At least 65% of its habitats has been eliminated and its current distribution is discontinuous and fragmented. Other habitats used by this species include grasslands and oak woodlands (Zeiner et al. 1988). This species is locally abundant in the foothills 2 miles southwest of the project and may occur in these farm pond-type wetlands or may be temporarily present in any seasonally wet area (CDFG 2001a; Larson 2001). In addition, the California Natural Diversity Database (CNDDB) contains sightings for the salamander near the corner of Kelso and Bruns roads. Proposed EAEC linear facilities on Kelso and Bruns roads would also pass through potential tiger salamander habitat. Presently the EAEC project site contains no suitable habitat for this species except that this species may occur in the irrigation ditches bordering the project site (EAEC 2001, page 8.2-14). To minimize the potential impacts of the EAEC to estivation and breeding areas of tiger salamanders, the applicant will need to obtain and comply with appropriate federal and state permits. In order to avoid significant impacts, mitigation will be required in the form of pre-construction surveys, and avoidance of habitats (CDFG 2001b).

Swainson's hawk *(Buteo swainsoni)*: This diurnal hawk is a state threatened species that may seasonally forage on the project site or in the project vicinity. The diet of the Swainson's hawk varies seasonally but largely depends upon abundant insects and small rodents, especially those found in alfalfa fields and open pasture (Zeiner et al. 1990). Nests are typically located in riparian areas, and large trees adjacent to agricultural fields. This species also forages at least 10 miles from nest sites, and roosts communally during migration (Zeiner et al. 1990).The applicant reported lack of suitable nest trees on-site, along linears, or adjacent areas, nor did they see hawks during surveys on May 4, August 14, 2000, or January 18, 2001 (EAEC 2001a, page 8.2-7).

The applicant collected data in the spring of 2001 on the proximity of nests (within ½ mile) to the EAEC. The locations of known nests will enable mitigation so that construction in the vicinity of those nests can be avoided during the active season. There are also no known communal roosts (used especially during migration) for this species on-site or on adjacent lands, but if one does exist or occur, the disturbance of birds using the roost would need to be avoided or minimized. The EAEC will result in loss of approximately 40 acres of hunting habitat for this species. This may be significant without mitigation because rapid urbanization is occurring in the project vicinity.

Golden eagle (*Aquila chrysaetos*): This large diurnal raptor is a state fully protected species and a species of special concern. Found in diverse habitats from open grassland, desert, canyon, savannah, and rolling and rugged hillside and plateau terrain, it forages for medium sized mammals (including fox, coyote, domestic livestock such as lambs and calves), rabbits, rodents, reptiles, birds, and carrion (Zeiner et al.

1990). This species is present in the vicinity of the EAEC particularly in the Altamont Hills. Because the hunting range for this species is large (over 100km^2), it may hunt and perch on site (Smith and Murphy 1973; Zeiner et al. 1990). Thus the EAEC will result in the permanent loss of 40 acres of potential foraging habitat for this species. This species typically nests on secluded cliff ledges and large trees where it constructs stick nests. No nesting habitat will be impacted by the EAEC. Generally, the impact to this species is insignificant with appropriate avoidance, and general habitat protection and mitigation.

White-tailed Kite (*Elanus leucurus*): This fully protected species inhabits oak grassland, rolling hills, and agricultural areas of California. It exhibits diurnal, and often crepuscular, activity patterns and hunts rodents, especially the California vole (*Microtus californicus*)(Zeiner et al. 1990). For nesting, this species prefers groups of tall thickly foliated trees and riparian areas adjacent to productive hunting areas (Erichsen et al. 1996). The kite is likely to be found hunting in the EAEC area. Its nesting habitats have been increasingly lost throughout California and its population status is largely unknown (Erichsen et al. 1996). There have been records of kites nesting in the EAEC vicinity (Bridges 2001) although the applicant did not report finding nests or communal roosts of this species on-site or within 5 miles of the EAEC project site. White-tailed kites roost communally in trees or on the ground and hunt in areas close to the roost. There is concern for this species among raptor biologists and CDFG, although it may be locally common. The hunting, and possibly communal roosting, habitat (approximately 40 acres) for the kite will be permanently and adversely impacted by the EAEC.

Burrowing Owl *(Athene cununcularia*): The burrowing owl is a state species of special concern which is likely to forage and breed in the EAEC project vicinity. This species uses ground squirrel burrows for nesting and cover, and hunts insects, small mammals, and birds in open grass and scrub habitats. Populations in California have declined significantly due to extensive habitat conversion to agriculture and urban uses, and associated impacts such as mortality from pesticides and increased vehicular traffic (Zeiner et al. 1990). However, this owl species has adapted somewhat by using agricultural crops and rangelands for hunting. This species also nests along ditches and agricultural fields. Surveys to avoid any nests will enable avoidance of harm to this species, and on and off-site mitigation will be required to ensure insignificant impact to this species. Thus, the EAEC will contribute directly to a loss of foraging and burrowing habitat for this species, but with mitigation, impacts will be insignificant.

Short-eared owl (*Asio flammeus*): This crepuscular owl is a state species of special concern. Historically, this species inhabited open grassland, meadows, wetlands, dunes, and scrub habitats throughout the entire length of California, excluding high mountains; but today the range of this ground-nesting owl has been reduced dramatically by human conversion of lands for urbanization, grazing, and agriculture (Zeiner et al. 1990). The diet of this owl species is specialized on small mammals, especially voles. Many of its remaining nesting and hunting habitats are agricultural lands, especially irrigated crops such as alfalfa. Plowing and harvesting, use of pesticides, depredation by feral animals, and burning of crop stubble are agricultural practices that adversely affect this species (Zeiner et al. 1990). Although this species was not reported by the EAEC during biological surveys, the site is clearly potential

habitat. The EAEC will remove approximately 40 acres of hunting (and possibly nesting) habitat for this species. Surveys to avoid any nests will enable avoidance of harm to this species, and on and off-site mitigation will be required to ensure insignificant impact to this species.

Northern harrier (*Circus cyaneus*): The northern harrier is a state species of special concern and is likely to inhabit the EAEC site and vicinity, although it was not discussed in the AFC. This diurnal, generalist raptor faces many of the same problems as the short-eared owl; it nests on the ground and has suffered a reduction in range due to human alteration and destruction of its preferred habitats including wetlands, meadows, and grasslands (Zeiner et al. 1990). This species attempts to nest in agricultural crops (grains) but may be adversely impacted by agriculture (burning, plowing, pesticides) and grazing (Zeiner et al. 1990). Any loss of agricultural and fallow or natural habitats due to the EAEC will like adversely affect this species. Mitigation measures will be required to detect and avoid nests prior to construction on-site and along linears. Additionally, habitat mitigation will be required for loss of foraging habitats. With mitigation impacts will be insignificant for this species.

Loggerhead shrike (*Lanius ludovicianus*): This carnivorous songbird is a state species of special concern. The shrike prefers open habitats such as grassland, cropland, rangeland, foothill scrub and woodland, and desert (Zeiner et al. 1990). Its populations have been declining in California due to urbanization, and it resides in the EAEC area year-round. It is a diurnal species which feeds on rodents, reptiles, and amphibians, and small birds (Zeiner et al. 1990). The EAEC will permanently remove 40 acres of hunting habitat for this species, which would not be significant if acreage surrounding the EAEC is protected and managed as cropland. No nest sites should be impacted because this species nests in shrubs and trees. This species may benefit from landscape plantings of small trees and shrubs around the EAEC.

California horned-lark (*Eremophila alpestris actia*): This is a state species of special concern which inhabits grasslands and is a good indicator of habitat quality for ground-nesting birds (Zeiner et al.1990). This species may forage in agricultural crops on the EAEC project site and larks may nest in fallow vegetation around the EAEC project site. Thus the EAEC will result in at minimum, a permanent loss of foraging habitat for this sensitive species.

Tricolored blackbird *(Agelius tricolor):* The tricolored blackbird (*Agelaius tricolor*) is a state species of special concern. Land conversion for agriculture and urban development, along with depredation from non-native predators and habitat degradation, are prime factors causing this species' decline (Zeiner et al. 1990). This colonial species requires fresh water and emergent vegetation, such as tule, cattails, and willow. This species is documented as being nomadic and unpredictable in terms of site fidelity. No suitable nesting habitat occurs on or adjacent to the EAEC project site, however, there are suitable habitat patches in the area along Byron Bethany Road at the Mountain House and unnamed creek. This species may also forage in agricultural crops on-site. To ensure that potential impacts to tricolored blackbirds are at insignificant levels, the applicant will be required to conduct pre-construction surveys for the EAEC power plant and linears and will avoid impact to wetlands. The applicant has

proposed to survey for this species within 100 feet of project features and to avoid construction in the vicinity of nests.

Mountain Plover (*Charadrius montanus*): This diurnal plover is a candidate for listing as threatened and is a state species of special concern. This species prefers open habitats lacking dense cover for foraging on insects, especially grasshoppers. As such it may be found in wetlands, grasslands, croplands, and especially plowed fields (Zeiner et al. 1990). This species nests on the ground from April through June, and is hunted by raptors, snakes, and mammals such as coyote, ground squirrels, badgers, kit fox, and skunks (Zeiner et al. 1990). The EAEC will result in loss of 40 acres of potential foraging habitat and nesting habitat for this species. With habitat mitigation, and pre-construction surveys for nests, impacts will be mitigated to less than significant levels.

San Joaquin Pocket Mouse (*Perognathus inornatus inornatus*): This mouse species is listed as a federal species of concern. As with other local species of concern widespread land development for agriculture and urban development are primary factors in this species' population decline. Endemic to the Central and Salinas valleys, this nocturnal, non-migratory mouse inhabits open grass and scrub habitats between 1,100 and 2,000 feet in elevation (Zeiner et al. 1990a). Burrow nests are built in fine-textured soils, such that plowing and soil ripping for agriculture collapse burrows and remove the fine sands and native plants these animals need (Zeiner et al. 1990a). This species is a generalist, feeding on seeds, green plant parts, and insects (Zeiner et al. 1990a). There is relatively little information about the present distribution and status of the species. Therefore, impacts to these species are of concern to USFWS.

Recent records indicate that the San Joaquin Pocket Mouse inhabits areas approximately 10 miles southwest of the project site, in the coastal foothills, at elevations closer to the 1,200 to 2,000 feet in elevation indicated in Zeiner et al. (1990a). The project site and surrounding areas and linears are all less than 100 feet in elevation, which is well below the reported range for this species (EAEC 2001a, page 8.2-14). Although the ecology and distribution of the mouse is poorly known, it is unlikely that the species would be present in the developed agricultural lands surrounding the EAEC project site. Thus project impacts to this species would not be significant.

Bats: There are several species of bats whose ranges are within the EAEC project area (Zeiner et al. 1990a). The species potentially found in Alameda county are all species of special concern and include: the Pacific western big-eared bat (*Corynorhinus townsendii townsendii*), the greater western mastiff bat (*Eumops perotis californicus*), the small-footed myotis bat (*Myotis ciliolabrum*), the long-eared myotis bat (*Myotis evotis*), the fringed myotis bat (*Myotis thysanodes*), the long-legged myotis bat (*Myotis volans*) and the Yuma myotis bat (*Myotis yumanensis*). Bat species are nocturnal and many feed on insects and use many structures for roosting, for example, caves, buildings, bridges, dead trees, and rock crevices (Zeiner et al. 1990a). According to current information on the project, bat roosts and nurseries were not found along project facilities, and will not be impacted directly, but the EAEC will remove 40 acres of foraging habitat. Bat species in the area will benefit from the habitat mitigation being proposed nearby. The impacts to habitat loss are thus insignificant, however, EAEC

buildings should be constructed to prevent bats from potentially establishing roosts in the area, and subsequently being harmed by human activities.

Western pond turtle *(Clemmys marmorata)*: This turtle is a federal and state species of concern. In the EAEC project area, the CNDDB contains records of western pond turtles at Mountain House Creek (4 miles southeast) and in Canal 70 (1 mile southwest). This species could occur in any open farm ponds or slow-moving waters in the vicinity. Although there are irrigation ditches bordering the south and east sides of the EAEC project site, there are no open ponds or other suitable aquatic habitats on-site (EAEC 2001a, page 8.2-14). The applicant will be required to avoid wetlands and other aquatic communities potentially inhabited by this species during construction and maintenance of the power plant and all linears. Thus, impacts to this species will be insignificant with the use of avoidance and minimization measures.

Impacts to Commercially-Important Species

Aside from fish in the Delta, discussed below, there are no known species of commercial importance that would be impacted by the EAEC.

Impacts to Special Status Delta Fish

The EAEC proposes to use fresh water for cooling. This water would be delivered by the BBID, which removes water from the California Aqueduct, and ultimately, the Sacramento-San Joaquin Delta (Delta) (EAEC 2001a, pages 8.2-19 and 8.14-4). Refer also to the **Soil and Water Resources** section of this Staff Assessment. The Delta is critical habitat for many declining or endangered fish species, such as winter run chinook, delta smelt, and Sacramento splittail (NMFS 2001a). The Delta also supports fish of importance to sport fishermen (EAEC 2001a page 8.2-19; NMFS 2001a). Staff is concerned with the levels of water to be withdrawn from the Delta due to the indirect and cumulative impacts this would have on native listed fish populations and their habitats.

The National Marine Fisheries Service (NMFS) has expressed concern for the potential of indirect ecological impacts of water diversions from the Delta, which is designated as critical habitat for these fish species. The species evaluated by the NMFS for impacts were: the federally endangered Sacramento River winter-run chinook salmon (*Oncorhynchus tshawytscha*), the threatened Central Valley spring-run chinook *salmon (O. tshawytscha*), and the threatened Central Valley steelhead (*O. mykiss*). The NMFS stated: “If diversions are not increased over current conditions, we would not anticipate adverse effects on listed salmon or steelhead, designated critical habitat or Essential Fish Habitat (EFH). *However, if diversions into the California Aqueduct are increased as a result of the construction and operation of the proposed project,* adverse effects on listed salmon or steelhead, designated critical habitat, and/or EFH may occur, and further consultation would be required.” (emphasis added) (NMFS 2001).

The EAEC will require approximately 4,600 acre-feet per year (AFY) of water, and up to 7,000 AFY in peak years. (EAEC 2001a, page 8.14-4). While Byron Bethany Irrigation District (BBID) – the water purveyor for the EAEC – maintains that serving the EAEC with this water will not result in additional water diversions to the California Aquaduct, staff has no evidence of this. Such a level of water diversion from the Delta, if it occurred, would cause potentially significant adverse impacts to listed fish populations

in the Delta (EAEC 2001a, page 8.14-4; EAEC 2001x, page 18). DWR as well has expressed concern that its beneficial uses under the SWP, or other Delta beneficial uses including maintenance of plantlife, fish and wildlife, could be injured. (CEC 2001i, page 1) Given that two other power plant applications being considered by the Energy Commission include proposals to withdraw freshwater from the Delta (i.e. the Tracy Peaker Plant and Tesla Power Plant), impacts to fish populations could be compounded and the combined water withdrawals could cause significant adverse cumulative impacts. The EAEC, and other power plants that withdraw water from the Delta, will continue to operate for several decades. Assessing and predicting the ecosystem impacts of such cumulative impacts is difficult without appropriate baseline data.

The question of whether or not the proposed supply of water for the EAEC would result in increased diversions from the Delta must be resolved before a final assessment of project impacts can be completed. As noted in the **Soil and Water Resources** section of this Staff Assessment, staff is awaiting additional information from DWR and the Applicant relative to previous Bay-Delta analyses and the relationship of BBID's water entitlements to those of the SWP and CVP. If staff determines that there could be increased diversions from the Delta, the applicant will need to consult a second time with NMFS. Until information received either confirms that there would be no net withdrawals from the Delta, or a second consultation with NMFS is completed, staff cannot conclude that there are less than significant impacts to native special status fish populations. If staff cannot confirm that there are no net withdrawals from the Delta, staff will additionally need to evaluate cumulative impacts.

Impacts Related to Landscaping and Visual Screening

There are visual impacts for which the applicant has proposed mitigation (refer to the **Visual Resources** section of this Staff Assessment). However, the visual mitigation may create significant adverse impacts to special status species. The applicant originally proposed to mitigate for visual impacts by using a 50-ft. setback area between the edge of Mountain House Road and the EAEC fence (EAEC 2001a, pages 8.11-28 and 8.11-29). Formal shrubs and informal evergreen trees were proposed to screen visual impacts along Mountain House Road and the western border of the facility. The applicant further proposed that the northern, eastern, and southern fence lines be landscaped with informal plantings of fast-growing evergreen trees.

In direct response to the above landscaping and visual screening proposal, the USFWS and CDFG unanimously indicated that such landscaping, while intended to mitigate for visual impacts, would result in unacceptable adverse biological impacts to listed, sensitive, and protected wildlife species (CDFG 2001a; Gan 2001a; Larson 2001). The landscape around the proposed EAEC was historically open grassland without many endemic trees except along streams and wetland areas. Presently, the area is highly modified with many types of exotic trees that have been planted around building structures, mainly for wind protection and visual screening.

It is a goal of CDFG and the USFWS to improve the management of habitats in the EAEC area in order to increase, stabilize, and restore special status wildlife. The USFWS, CDFG, and staff have determined that it is not ecologically defensible to add trees in this area. This conclusion is based upon the natural history of the area and is underscored by the aforementioned management objectives to protect and restore

special status species. The area around the EAEC still provides significant habitats, which connect increasingly fragmented habitat patches and provides potential dispersal, hunting, and nesting habitats for many special status species.

In particular, the USFWS and CDFG identified the concern that large trees and shrubs would provide nesting (and perching) sites for large raptors that would prey upon San Joaquin kit fox, burrowing owl, and other special status species. The plantings would also provide refuge and hunting cover for terrestrial predators (i.e. coyote, and the non-native red fox). This would provide the predators with an advantage that would harm remaining populations of special status species. Ultimately, the adverse impacts of the landscape plantings would cause the remaining lands around the EAEC to act as a habitat "sink" and not a source of support for wildlife. A habitat sink is an area, which may attract wildlife and provide habitat, but also contains threats and adverse conditions, such as habitats preferred by predators (Meffe and Carroll 1997). The result for a given species is that the mortality rate becomes greater than reproductive success and survival and the habitat becomes a sink which causes a species' decline (Meffe and Carroll 1997; Pulliam, H.R. 1988). The adverse impacts of the proposed landscaping and screening to federal and state listed species protected under the Federal Endangered Species Act and California Endangered Species Act, would significantly outweigh the benefits to visual objectives. This must be avoided and the direct means of achieving that is to prohibit the planting of tall evergreen trees and shrubs.

There are also policies in Alameda County that are pertinent. Policies 113 and Program 51 require that landscaping enhance the scenic quality of the area while remaining compatible with habitat values, water use, and fire retardance. Policy 51 lists non-native invasive plants that should be avoided for landscaping. Policies 118, 119, and 120 place priorities on preserving open space and enhancing and managing these areas for sensitive wildlife and protecting biological diversity. The proposed landscaping may also violate the intent of these policies by planting non-native species and planting them in a manner, which harms special status species (per comments of USFWS and CDFG).

The applicant has attempted to resolve the conflict between the requirements of Biology and Visual Resources (EAEC 2001y, page 2). A public meeting was held on September 12, 2001 to discuss the nature of the conflict. Representatives of the USFWS, CDFG, CEC, and the EAEC were present. At the meeting, USFWS and CDFG stated the rationale behind their position and reiterated their assertion that the landscaping as proposed in the AFC would not be acceptable and would create additional potentially significant biological impacts.

As a result of the public meeting on this issue, the applicant agreed to provide new analyses and designs for the landscaping around the EAEC. An alternative visual screening/landscaping proposal was received November 7, 2001. This submittal is discussed below in the applicant-proposed and staff-proposed mitigation sections. The analysis of this issue will continue until a suitable result is achieved for the protection of biological resources.

Construction Impacts

The proposed generating facility site would require up to a 40-acre footprint (EAEC 2001 section 8.2 pages 17-18). Construction of the generating facility and linears will

result in permanent loss of approximately 40 acres as well as temporary disturbances to approximately 56 acres.

The proposed construction laydown area will be compacted and overlain with a layer of gravel or other material. Upon completion of laydown, the site is designiated be returned to agricultural use (EAEC 2001a page 8.2-28) or restored as natural vegetation. Staff prefers restoration as native vegetation where feasible. The construction of the gas and water supply lines will require trenching, expected to be 4-ft wide by 4-ft. deep. Construction of the natural gas supply line would require a disturbance 75 feet wide by 1.4 miles long (for alternative 2A), including two pads 100 by 115 feet for horizontal directional drilling (HDD) staging areas (see acreage impacts provided in **Biological Resources Table 2**). Construction of the water supply line would also require trenching and temporary construction laydown area, 75 feet wide by 2.4 miles long (see acreage impacts provided in **Biological Resources Table 2**). Lastly, temporary disturbances will result from the installation of the transmission line, including a construction access road and laydown area comprising 0.5 acre of agricultural land. Thus ,Construction activities have the potential to disrupt foraging, nesting, and survival of sensitive plant and animal species. General impacts from construction which must be minimized or eliminated, include:

- Dust and air pollution (see **Air Quality** section of this Staff Assessment);
- Erosion and water degradation (see **Soil and Water Resources** section of this Staff Assessment);
- Excess noise (see **Noise** section of this Staff Assessment);
- Traffic; and
- Damage or mortality of sensitive biological resources, using measures such as speed limits, exclusionary fences, and pre-construction biological surveys.

The above impacts are significant but can be mitigated to less than significant levels with appropriate habitat compensation and the implementation of avoidance and minimization measures. Adverse impacts of construction activities will be monitored and avoided, minimized and mitigated per conditions set forth in the Conditions of Certification (See Conditions of Certification **BIO-7** and **BIO-8**).

Operation Impacts

Operation of the proposed project will results in HRSG emissions, cooling tower emissions, and noise and lights from plant operations, all of which may cause impacts to biological resources on the site and adjacent areas (EAEC 2001 section 8.2.3.4). Power plant facilities may also cause impacts from avian collisions with the HRSG stacks and transmission lines.

Impacts from Air Emissions

Staff is continuing to request accurate and complete data from the applicant in the area of air quality. Thus, a complete analysis is pending receipt of essential and amended data. However, staff tentatively provides the following analysis with available data.

Heat Recovery Steam Generator (HRSG) Emissions: Air emissions from the two HRSG stacks will contain air pollutants such as nitrogen oxide gases (NO_x), sulfur oxides (SO_x), and PM10 (discussed in the **Air Quality** section of this Staff Assessment). Nitrogen oxide gases may be converted to nitrate particulates which, when deposited on the ground, could adversely affect vegetation communities adapted to low nutrients (Weiss 1999). There are no such plant communities in the vicinity of the EAEC. Nitrogen dioxide is phytotoxic at exposures considerably higher than those resulting from most industrial emissions. Acute exposures (1-hour) of 18,000 µg/m^3 are reported in the scientific literature to result in leaf damage. Chronic exposures of lower levels ranging from 280 to 490 µg/m^3 may result in decreased dry weight and leaf area (EAEC 2001a, page 8.2-27). The predicted maximum EAEC emissions of NO_x are 0.80 µg/m^3, levels far below the cited threshold limits. In addition, the total predicted maximum 1-hour NO_x concentrations of 72.6 µg/m^3 (with infrequent concentrations of 204.7 µg/m^3 during emergency and test operations) will be significantly lower than the 1-hour threshold (7,500 µg/m^3 or 3,989 parts per million) known to cause 5 percent foliar injury to sensitive vegetation (EAEC 2001a, page 8.2-27). Finally, there are no identified sensitive soils, such as serpentine soils, which are known to support particularly sensitive ecological communities. Thus, the HRSG emissions are not predicted to cause significant impacts to biological resources with the proposed emission controls.

Cooling Tower Drift: Maximum cooling tower drift from the cooling tower would be 0.0005 percent of the circulating water flow. Cooling water would be emitted as mist with a peak hourly rate of 85 gallons per hour during 98°F air temperatures (EAEC 2001a, page 8.2-25). The small amount of temporary moisture produced daily from the cooling towers is not expected to change the microclimate of the area (EAEC 2001a, page 8.2-25).

Cooling towers produce a fine mist of water that escapes the cooling tower and are emitted into the atmosphere. This mist contains particulates (total dissolved solids) which concentrate in the water to produce a salt mist. Biologically, cooling towers may result in adverse impacts if chemicals such as ammonia, arsenic, cadmium, chromium, copper, lead, mercury, nickel, silver, and zinc become concentrated at high levels. Once deposited, the dissolved solids impact vegetation by physically damaging the cells of leaves, especially on young plants, and affecting the photosynthetic ability of the plant. The applicant cites work by Pawha and Shipley (1979), who exposed vegetation (corn, tobacco, and soybeans) to saltwater ranging from 20 to 25 parts per thousand in order to simulate drift from cooling towers; the results indicate that salt stress symptoms on the most sensitive crop plants were barely perceptible at a deposition rate of 2.98 grams per square meter per year (g/m 2 /year) (Pawha and Shipley, 1979). EAEC emission levels are predicted to be much less than these levels, and therefore, no significant impacts will result.

The maximum annual predicted deposition for P_{M10} from the project (including cooling towers) is 0.6 µg/m^3 (EAEC 2001, page 8.2-26). The applicant assumed a maximum deposition velocity of 2 centimeters per second (cm/sec), and predicted an annual deposition rate of 0.4g/m^2/year)(EAEC 2001, page 8.2-26). The estimated deposition rate for P_{M10} from the EAEC, including cooling tower drift, is thus approximately one order of magnitude below the deposition rate that was shown to cause barely perceptible vegetation stress from salt mist (2.98 g/m^2/year) in the most sensitive

plants. Quarterly wind data indicate that prevailing winds are out of the northwest and would cause cooling tower drift to be directed mainly away from potentially sensitive plant areas to the south, southwest and west (EAEC 2001a, Figures 8.1-1 to 8.1-4). Thus, based on current data, cooling tower drift is not expected to have any significant impact on vegetation in surrounding areas within the maximum impact radius for the cooling tower drift.

Amphibians are particularly sensitive to atmospheric chemical pollutants; however, the cooling tower drift is not expected to have an impact on either the California red-legged frog (*Rana aurora draytonii*) or California tiger salamander (*Amybstoma californiense*). The nearest documented populations of these species are to the south, southwest, and west of the EAEC site and will not be impacted by the EAEC emissions. Cooling tower drift impacts on sensitive vegetation or wildlife species near the project site are not expected to be significant. The applicant will be required to use Best Available Control Technology (BACT) to minimize all sources of air emissions and minimize biological impacts to an insignificant level.

Cooling Tower Effluent: The cooling process also produces cooling tower effluent (blowdown) after the water has cycled through the cooling towers. This process concentrates particulates such as calcium salts, thereby increasing the salinity of the discharge water. This water would not be discharged but treated on-site in a multimedia filtration system which includes a brine crystallizer/dryer system (EAEC 2001v, Supplement B page 3). Thus, no biological impacts are expected.

Impacts from Avian Collisions with Facility Structures

Avian collisions with Heat Recovery Steam Generator **(**HRSG) stacks occur when the birds are unable to see the stacks during fog and rain events or during migration when birds frequently fly at night (CEC1995; Kerlinger 2000). Factors known to increase the risk of avian collisions include: the stack location, size, visibility, weather conditions (fog, rain), and species-specific flocking and flight behaviors. Site-specific placement of the towers as well as local seasonal bird occurrence and behavior also contribute to risk factors for avian collision and mortality with stack structures and wires (CEC 1995; Kerlinger 2000; Manville 1999). Specifically, the EAEC is surrounded by agricultural fields, which provide attractive foraging habitat for birds such as egrets and herons, ducks and geese, shorebirds (i.e. curlews and yellowlegs). Raptor species may also be at risk, including the golden eagle, white-tailed kite, and Swainson's hawk.

Most of the research on avian collisions with towers has focused on structures greater than 500 feet tall. The EAEC stacks are proposed to be only 175 ft tall and there are little data quantifying avian collision and mortality due to structures less than 200 feet tall. Thus, due to site-specific conditions, and lack of data for the area, the HRSG stacks cannot be ruled out for their potential to result in bird collisions. Therefore, staff recommends consideration of a monitoring program to provide a proper basis for determining impacts and mitigation.

Impacts from Noise and Lighting

Operation of the EAEC will produce some noise as described in the AFC (2001a) section 8.5 (pages 8.5-10 to 8.5-13) and in recently submitted analyses (EAEC 2001w received October 10, 2001). For a detailed analysis of noise impacts, refer to the **Noise** section of this Staff Assessment. The quiet environment surrounding the EAEC typically has L90 levels between 30-45dBA during the night and L90 levels between 35-45 during the day, mostly due to distant traffic (EAEC 2001a, page 8.5-6; EAEC 2001w, pages 40-42). The increases (over 5dB) from the plant would be significant and would need to be mitigated (EAEC 2001a, page 8.5-8). The predicted operational noise levels are below 60 dBA, threshold levels hypothesized to cause potentially significant disturbance to wildlife. Highly sensitive reptiles, birds, or mammals are not expected to breed on-site or in adjacent agricultural fields. Available data on the expected noise levels do not indicate significant risk that long-term operations will adversely impact wildlife because levels will be below 60dBA. In addition, mitigation for noise levels will be implemented (EAEC 2001 page 8.2-27; EAEC 2001p pages 40-42 and 43-44; EAEC 2001w, page 5). Noise levels from plant operation will not cause significant adverse impacts to wildlife after approved mitigation is implemented.

Construction activities will temporarily increase noise levels more than plant operation levels. Construction equipment, such as concrete mixers, backhoes, jackhammers, and drills can produce noise levels that can range from 78-89 dBA. Such activities frighten wildlife away, disrupt their nesting, roosting, or foraging activities, or prevent them from using the habitats available around the EAEC. Many species of wildlife are able to adapt to construction noise once they associate it with non-threatening activities. Noise impacts from construction will need to be mitigated with appropriate technology and avoidance of sensitive resources. Noise levels from construction will not cause significant adverse impacts to wildlife upon implementation of appropriate mitigation measures.

Lighting will also be required on-site. Bright night lighting will disturb the resting, mating, or foraging activities of wildlife. Lights may also make roosting or nesting birds more visible to predators. Night lighting is also suspected to attract migratory birds to areas, and if the lights are on tall buildings or HRSG stacks, collisions could occur (EAEC 2001a, page 8.2-27). To reduce these effects, lighting would be pointed down to minimize impacts (EAEC 2001a, page 8.2-27). The color of the lighting may also be an important factor to be considered and modified. The efficacy of this mitigation will need to be monitored using methods defined in the BRMIMP. Corrective actions will be required as needed.

Maintenance Impacts

Maintenance activities on the EAEC site include keeping vegetation clear of the fence line for fire control. An area approximately 10 feet wide around the fence line will be kept mowed. The use of rodenticides will be prohibited and herbicides and insecticides will be restricted to those with high specificity, low toxicity, and rapid environmental degradation.

IMPACTS FROM LINEAR FACILITIES

Natural Gas Supply Pipeline

Alternative 2A (the applicant's preferred alternative) covers 1.4 linear miles. It exits the project site to the south, following Kelso Road west to the Bethany Compressor Station just east of Bruns Road where it will interconnect into PG&E Line 401.

Alternative 2A is staff's preferred route because it would be installed beneath existing ruderal vegetation along the north side of an existing right-of-way on Kelso Road. This option minimizes potential impacts to biological resources by avoiding agricultural fields to the south of Kelso Road.

Alternative 2B was eliminated as an alternative in the AFC because of potential adverse impacts to sensitive biological resources.

Alternatives 2C, 2D, and 2E would impact sensitive habitats near and within the California red-legged frog Recovery Plan "core" habitat area and are thus eliminated from consideration by staff.

Impacts due to construction of the pipeline will be temporary disturbance of ruderal vegetation along the north side of the road. Because there are sensitive habitats in that area, several practices can be implemented to avoid impacts. Wetlands to the north and south of Kelso Road will be avoided completely. With proper avoidance and minimization mitigation, impacts from installation of the gas pipeline (preferred route A) will be insignificant.

Operation of the gas pipeline will not impact the biological resources unless a leak occurs. A leak could result in fire thereby potentially impacting biological resources.

Maintenance of the gas pipeline will involve weed control above the pipeline route along Bruns Road and Kelso Road. Maintenance techniques must be ecologically sound, performed by a trained employee who is aware of sensitive biological resources in the area, and in accordance with any permits required by state and federal agencies.

The BRMIMP will contain all mitigation measures to be implemented along the gas and water pipelines.

Water Supply Pipeline

All proposed water supply pipeline alternatives would be less than four miles long and would avoid the most sensitive biological resources in the area (EAEC 2001a, Figures 8.2-1 and 8.2-2). The extent of potential biological impacts depends upon which of the four feasible alternative routes is implemented (See the **Soil and Water Resources** section of this Staff Assessment).

Alternative 3A would require 2.6 miles of pipeline from the pump station in Canal 45, north along Bruns Road and then southeast along Byron Bethany Road to the EAEC (EAEC 2001a, Figure 1.1-2). This alternative would be along existing paved roads and ruderal roadside vegetation and would completely avoid sensitive habitats. In addition

crossings of waterways would be made using horizontal directional drilling or placement of pipes on top of existing culverts.

Alternative 3B would be 3.6 miles in length. It would use the existing Canal 45 and Canal 70 and associated pump stations to transport water from the California Aqueduct to the intersection with Mountain House Road. A pump station and a 3,000-foot (0.6 mile)-long pipeline would need to be installed at the intersection of Canal 70 and Mountain House Road, so that water could be transported across Mountain House Road and north to the EAEC (EAEC 2001a, page 7-9). Wetland habitats exist in areas adjacent to this alternative route and these areas would be subject to ACOE and/or CDFG permits if any construction disturbance affected these areas. This alternative could result in potentially significant adverse impacts.

Alternative 3C had already been eliminated by the applicant in the AFC (EAEC 2001a, page 7-8) due to concerns for its potential to adversely impact local biological resources.

Alternative 3D would be 2.4 miles long and is similar to Alternative 3A and Alternative 3E. It would require lining Canal 45 from the California Aqueduct to the new pump station at Canal 45 and Bruns Road. The pipeline would run south along Bruns Road east o the Delta-Mendota Canal, and then north to Byron Bethany Road. The pipeline would then be installed south along Byron Bethany Road and cross Mountain House Road to reach the project site. This alternative would require: open-cutting across Mountain House Road, crossing a high-pressure oil pipeline, crossing Canal 45 along the gravel road, and overlaying large box culverts that route the Delta-Mendota Canal. This alternative is more complicated to build and permit, and may traverse sensitive habitats. As such, it is not a preferred route of staff.

Alternative 3E (the applicant's preferred alternative) is similar to the route associated with Alternative 3D, except that it would only be 2.1 miles long because it would travel east along a gravel road and cross under the Delta-Mendota Canal directly west of the project site. From this location, the pipeline would proceed directly to the EAEC. The crossing of the Delta-Mendota Canal would be done using horizontal directional drilling methods. This alternative would not cross the high-pressure oil pipeline along Byron Bethany Road and the large box culverts that route the Delta-Mendota Canal water under Byron Bethany Road.

Staff also prefers route 3E and concurs with the applicant's avoidance of sensitive habitats, installation of the pipeline down the middle of the existing road, and the use of HDD for installing the pipeline along the edge agricultural fields and under the Delta-Mendota Canal. If construction requires disturbance drainages or sensitive habitats, a CDFG Streambed Alteration Agreement may be needed.

The impacts to biological resources from the water supply pipeline are projected to be insignificant because wetland and sensitive species will be surveyed prior to construction and avoided. There have been no specific records of sightings or burrows along the linear alignments, but pre-design surveys will be implemented to be certain that waterline construction does not disturb an existing burrow or den. The berm along the Delta-Mendota Canal is potential San Joaquin kit fox denning habitat, but pre-design surveys also did not identify any potential dens in this area. Specific environmental

awareness, training, and monitoring measures will be implemented as determined in consultation with USFWS to avoid adverse impacts to kit fox.

Construction impacts would be temporary and because the applicant plans to install the pipes in the road and use horizontal directional drilling across waterways, the temporary and permanent impacts are negligible. The Byron Bethany Irrigation District's (BBID) normal maintenance schedule for the canals includes cleaning the canals of aquatic weeds, other vegetation, and periodic canal bank reshaping during the months of November - March. To facilitate a more continuous operation of BBID's facilities, concrete canal lining, and a water control structure will be used on those existing canals that are incorporated into the water supply features for the EAEC. All construction will be required to comply with conditions specified in applicable permits from CDFG and/or ACOE.

Operation Impacts: Operation of the water supply line would not cause impacts to biological resources unless a leak should occur. Leakage of the water supply pipeline could result in localized ponded water, which could impact both vegetation and animals.

Maintenance Impacts: It is anticipated that the water supply line will be buried and not require surface disturbance for maintenance. Therefore, no significant impacts resulting from pipeline maintenance are expected.

Decommissioning Impacts: Decommissioning of the water supply pipeline could involve digging the pipeline out of the ground. These activities would cause similar impacts as the construction impacts mentioned above. The pipeline could also be sealed and left in place, which would not cause impacts to biological resources.

Recycled Water Supply Pipeline

The recycled water supply provided in the AFC is speculative and may not be feasible; refer to the **Soil and Water Resources** section this Staff Assessment for analysis of the water supply. Despite the uncertainty regarding the water supply, staff must analyze the biological impacts of the proposed recycled water pipeline. The applicant has proposed two pipeline routes both of which would be installed along Byron Bethany Road, the railroad, and though agricultural fields, and would require construction of the Mountain House Community Sanitation District Waste Water Treatment Plant (EAEC 2001a, Figure 1.1-2, and page 8.2-16).

The applicant's preferred route would be 4.6 miles long and would be installed using trenching (EAEC 2001a; Table 8.2-2). Construction of the pipeline may temporarily impact emergent freshwater wetlands at the intersection of Mountain House Creek and a small drainage crossing Byron Bethany Road (EAEC 2001a, Figure 1.1-2, and page 8.2-16). Ruderal vegetation along rights-of-way and agricultural vegetation would also be temporarily impacted (EAEC 2001a, page 8.2-16; EAEC 2001r; pages 4, and Attachment WR-86). Permanent habitat disturbance will include 0.2 acres, while temporary habitat impacts will occur on 25 acres (EAEC 2001a; Table 8.2-2).

Special status species, such as the San Joaquin kit fox, California red-legged frog, western pond turtle, Swainson's hawk, and burrowing owl may be impacted by construction because these species inhabit the area. A kit fox den was identified less

than 2,000 feet from the area of the proposed water source, and Swainson's hawks also hunt and nest in the area (EAEC 2001a; Figure 8.2-2). The California red-legged frog and pond turtle were not detected during surveys (EAEC 2001a; Figure 8.2-2). Impacts to fish may also result from construction. Temporary impacts to special status species and habitats (wetlands, ruderal, and agricultural) may be mitigated to less than significant impacts with avoidance and minimization measures as well as compliance with conditions contained in required CDFG and ACOE permits.

Operation Impacts: Operation of the water supply line would not cause impacts to biological resources unless a leak should occur. Leakage of the water supply pipeline could result in localized ponded water, which could impact both vegetation and animals.

Maintenance Impacts: It is anticipated that the water supply line will be buried and not require surface disturbance for maintenance. Therefore, no significant impacts resulting from pipeline maintenance are expected.

Decommissioning Impacts: Decommissioning of the water supply pipeline could involve digging the pipeline out of the ground. These activities would cause similar impacts as the construction impacts mentioned above. The pipeline could also be sealed and left in place, which would not cause impacts to biological resources.

Transmission Lines

The EAEC will interconnect to the Modesto Irrigation District and Turlock Irrigation District (MID/TID) 230-kV transmission line running along Kelso Road approximately 0.5 miles south of the project site. The MID/TID line will be routed into and out of the EAEC switchyard in a north/south orientation on separate transmission poles and will be approximately 260 feet apart. The EAEC's transmission line will be only 0.5 miles long, and it will exist within an area of high migration and daily movement of birds, especially waterfowl and raptors.

Electrocution may result in serious impacts to bird populations and typically occurs when a bird simultaneously contacts two conductors of different phases or contacts a conductor and a ground (CEC 1995; CEC 1999). If there is not sufficient clearance between these elements, electrocutions may occur. In general, transmission lines larger than 65 kV have sufficient clearance between these elements to protect large birds from electrocution. Installation of transmission lines and related facilities according to the guidelines suggested in the Avian Power Line Interaction Committee report (APLIC 1996), Harness (2000) and CEC (1999) will provide a means to eliminate most impacts associated with electrocution.

Collisions of birds with EAEC transmission lines may be a measurable problem because the EAEC project area attracts many bird species. However, the impacts may not be limited to EAEC facilities, but rather, may be occurring on adjacent transmission lines. Ultimately, the EAEC has the potential to create an increase in avian collisions with the new transmission lines and staff concludes that a monitoring plan would provide the data needed to confirm the impact, or lack thereof. The monitoring plan would be combined to monitoring for avian collisions with stacks as well.
Construction impacts of the transmission line will include the permanent removal of at least 500 ft sq. of agricultural vegetation on the south side of the Western Substation.

The areas under the towers would be temporarily disturbed by equipment (flatbed and crane) during construction.

Maintenance impacts may include increased traffic and the storage of equipment during repairs. Impacts should be minimal when best management practices are implemented (see Conditions of Certification **BIO-7** and **BIO-8**).

CUMULATIVE IMPACTS

Cumulative impacts are defined as "two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts." (California Environmental Quality Act Guidelines, Section 15355). A cumulative impact is one which results from the combination of impacts associated with the proposed project, in addition to those resulting from separate projects in the region; these additional projects may be underway or may be planned in the future and must cause similar adverse impacts. Cumulative impacts can result from individually minor, but collectively significant, actions taking place over time.

The proposed EAEC will permanently remove approximately 40 acres of wildlife habitat. There are two additional energy projects to be reviewed by the California Energy Commission that are proposed close to the EAEC. Midway Power, LLC submitted the Tesla AFC on 10/12/01. Tesla is proposed as a 1,120 MW combined cycle facility located on a 160-acre parcel in Alameda county, less than 10 miles from EAEC. The second AFC (submitted 8/16/01) is for the Tracy Peaker Project, a simple cycle 169 MW facility within a 40-acre parcel near the City of Tracy. In addition, the new town of Mountain House has been approved less than 1 mile southeast of the proposed EAEC. Mountain House is projected to achieve maximum build-out by the year 2024 and have a population of at least 40,000 people (EAEC 2001p, page 55). These proposed projects will result in significant cumulative adverse impacts to terrestrial habitats for special status species, such as the San Joaquin kit fox. These projects may also use freshwater in a manner that causes significant adverse impacts to endangered populations of native fish species.

Staff must ensure that potentially cumulative impacts from the EAEC are mitigated. The EAEC will contribute to the cumulative loss and degradation of habitats essential to the persistence and recovery of special status wildlife species. Other significant cumulative impacts may include the project's use of prime agricultural and open space, water use (i.e. diversions from the Delta which impact Delta fish), and contribution to air pollution levels. Cumulative impacts may be reasonably mitigated to less than significant levels with a well-designed habitat compensation package that considers the importance of habitat quality, quantity, and connectivity and which is managed intensively for special status species. The implementation of alternative cooling technologies, that preclude the use of freshwater, may also be required to mitigate for adverse impacts to Delta fish species. Staff requires additional information on water use from the applicant, as well as additional analysis of cumulative impacts to Delta fish species. Cumulative impacts of the EAEC will be further considered in consultation with the USFWS, CDFG, NMFS, and Western.

MITIGATION

APPLICANT'S PROPOSED MITIGATION:

The Applicant has proposed a variety of mitigation measures to offset habitat loss and adverse impacts caused by construction, operation, maintenance, and closure (EAEC 2001a, section 8.2.3; EAEC 2001u, pages 1-21).
The applicant has proposed to mitigate for adverse impacts to biological resources with the following actions (EAEC 2001, pages 8.2-24 to 8.2-25; EAEC 2001u, pages 11-12).
The applicant will be responsible for obtaining a Section 7 permit with Western acting as the lead agency. The applicant must comply fully with conditions of the biological opinion issued by USFWS as well as those issued by the CDFG. The applicant has agreed to abide by the conditions of the Section 7 permit, which include the following additional mitigation/protective measures that would be implemented in these sensitive areas. The applicant also committed to avoid wetlands and implement wetland and waterway protection measures (EAEC 2001u, pages 12-15).

Habitat mitigation

The Section 7 permit will specify actions that will are required to avoid, minimize, or compensate for any potential adverse impact to listed and sensitive species and their habitat, especially that of the federally endangered San Joaquin kit fox, the California red-legged frog, and California tiger salamander (as a federal candidate species).

Persuant to Section 7, the applicant has proposed to mitigate for significant adverse impacts to listed species by providing the money to purchase suitable mitigation habitat. Specifically, habitat will be selected as mitigation for San Joaquin kit fox, California red-legged frog, California tiger salamander, and will also benefit other special status species (EAEC 2001p, pages 1-2). In accordance with USFWS recommendations, the compensation ratios are proposed as follows: 3.0:1 for permanent impacts with an ability to acquire moderate quality habitat ranging to 5.0:1 for lower quality habitat, and 1.1:1 for temporary impacts (EAEC 2001w, page 1). Mitigation property near the project and along a habitat corridor would be more valuable than a property far away and disconnected to local wildlife habitats.

The applicant proposes several alternatives, of which one or more may be implemented:
1. Purchase of land to be managed for sensitive species.
2. Purchase of credits in a mitigation bank (no longer a feasible option)
3. Implementation of a habitat restoration and management plan on-site.
4. Implementation of a red fox control program.

The applicant has identified two land management groups that are potentially qualified to manage mitigation lands (EAEC 2001w, page 2). These groups include: the Center for Natural Lands Management and Wildlands Incorporated.

Avoidance and Minimization Measures to Protect Special Status Species

Specific measures proposed by the applicant to mitigate for impacts to special status species are as follows:

Federal and State Endangered or Threatened Species

San Joaquin Kit Fox:

1. Obtain and comply with the conditions of a Section 7 authorization for incidental take of this species.
2. Conduct pre-design surveys for all areas potentially affected by the project.
3. Set and enforce speed limits in the construction area at 20 miles per hour or less.
4. Provide any excavations or ditches with escape ramps and check for trapped wildlife before work commences each day.
5. Cap pipes over 4 inches in diameter or check before they are moved.
6. Implementation of procedures and recommendations published in the USFWS guidelines for San Joaquin kit fox (USFWS 1997).

California Red-legged Frog:

1. Conduct pre-construction surveys in the spring (before February 1) of the project site and project linears to determine if suitable habitat may be occupied.
2. Avoid all suitable breeding habitats.
3. If suitable breeding habitat cannot be avoided, implement measures to temporarily relocate frogs or other measures as required by USFWS.

Species of Special Concern

Tiger Salamander (also a Candidate for Federal Listing):

1. Pre-construction field surveys should be implemented to identify potentially suitable habitat.
2. Avoidance and minimization measures to protect habitats from impacts.

Swainson's Hawk:

1. Implement nest surveys within ½ mile of project features to determine use by Swainson's hawk.
2. If project features are within ½ mile of Swainson's hawk nesting, avoid construction within ½ mile during nesting season if feasible.
3. If construction cannot avoid active nests by ½ mile, project applicant will apply for and comply with an incidental take agreement under Section 2080.1.

Burrowing Owl:

1. Conduct pre-construction surveys in the spring (before February 1) of construction areas to determine if habitat is occupied by burrowing owls.
2. Implement mitigation measures that protect burrowing owls by passive relocation and/or restriction of construction activities within 150 feet during non-breeding season or 250 feet of active burrowing owl nest burrow during breeding season (February 1 through August 31).
3. Incorporate areas in landscape/mitigation corridor for forage and potential burrow habitat.

California Horned Lark:

The project applicant has proposed to perform surveys at the appropriate time of year to identify locations of potential nests within 100 feet of project features. Construction in the vicinity of nests will be avoided (EAEC 2001a, page 8.2-13). Biology staff supports this mitigation strategy and would also require habitat mitigation, that provides suitable foraging habitat for this species.

Tricolored Blackbird:

The applicant has proposed to conduct pre-construction surveys for this species within 100 feet of project features and to avoid wetlands as well as construction in the vicinity of nests.

Foraging Raptors (including the loggerhead shrike), Herons, Egrets, and Waterbirds:

1. Design "raptor-friendly" electric transmission lines as described in the "Suggested Practices for Raptor Protection on Power Lines: The State of the Art in 1996" (APLIC, 1996).

2. Provide safety lighting that points downward on the HRSG stacks to reduce avian collisions.

3. Lease the 134-acres of land surrounding the EAEC for use in wildlife-friendly agriculture (per USFWS and CDFG guidelines).

Mitigation for Impacts to Native Fish: The applicant has not proposed mitigation because it deemed the impacts to be insignificant.

Mitigation for Landscaping and Visual Screening: On November 7, 2001 the applicant provided the latest landscaping proposal (Environmental Vision 2001a). The design proposes to plant narrow trees which range in size from 40-100 ft (*Populus nigra italica* and *Casuarina cunninghamiana*), 25-50ft (*Schinus molle*), down to 10-25 ft. (*Ceris occidentalis, Feijoa sellowiana, Cragaegus phaenopyrum, and Callistemon citrinus*). The plantings would be designed to achieve specific objectives for screening and avoid specific impacts to biology. Large trees would be avoided to prevent nesting of golden eagle. The ground level vegetation was proposed to be trimmed up to 3 ft. above the ground to prevent cover for mammalian predators.

Mitigation Practices for Construction

The applicant has proposed several mitigation measures as follows (EAEC 2001a, page 8.2-25; EAEC 2001u, pages 10-11):

- Provide mitigation construction monitoring by a qualified Designated Biologist during construction activities near sensitive habitats.
- Provide all EAEC employees with environmental awareness training from the Designated Biologist (required in staff's proposed Condition of Certification **BIO-4**) in order to ensure that employees are:
- Aware of sensitive natural resources on site and in the project area;

- Compliant with EAEC best management practices and procedures for protecting biological resources at all times; and
- Able to conform with the BRMIMP and general mitigation measures at all times (required in staff's proposed Conditions of Certification **BIO-7** and **BIO-8**).
- Submit the Biological Resources Mitigation Implementation Monitoring Plan (BRMIMP) which needs to be approved by staff in consultation with the USFWS, NMFS, CDFG and Western.
- Avoid sensitive habitats and species during construction by developing construction exclusion zones and silt fencing around sensitive areas.
- Conduct additional pre-construction surveys for sensitive species in impact areas during the spring before construction begins, especially near the Delta-Mendota Canal.
- Prepare construction monitoring and compliance reports, which indicate the effectiveness of the mitigation measures.
- Construction materials and equipment would be delivered to the site and laydown area by truck from existing roads.
- The temporary construction laydown area would be removed and restored as soon as feasible after construction was complete (EAEC 2001a, page 8.2-28).

The applicant did not provide specific mitigation for decomissioning of the power plant facility but rather has stated its intention to provide mitigation appropriate to potential effects at a time closer to the plant closure process. Overall, the applicant suggests that the area may return to agricultural or open space use (EAEC 2001a, page 8.2-27).

The noise from construction activities will be restricted from 7a.m.-7p.m weekdays and 9a.m.-7p.m. weekends (EAEC 2001a page 8.5-8 Table 8.5-4). To mitigate for noise levels the applicant proposes to use silencers during blowout to reduce noise levels from approximately 95 dBA to levels below 55 dBA (EAEC 2001p, pages 43-44).

Mitigation for Natural Gas and Water Pipelines.

EAEC states that measures previously identified for project construction would apply to all project linears. Specifically the applicant provides the following list (EAEC 2001a, section 8.2.3.5):

- All project linears would be surveyed prior to construction to identify significant biological resources that require avoidance or protection.

- Avoidance, protection and worker awareness training would be detailed in the project Biological Resources Management and Implementation Plant (BRMIMP).

- Construction would be constrained within a designated construction corridor, generally 75 feet wide or less.

- Any wetlands crossed by project linears would be avoided, or crossed in compliance with conditions specified by a Section 404 Permit or Streambed Alteration Agreement, as appropriate.

- Sensitive and special status plants occurring in pipeline rights-of-way would be removed prior to construction.

- The impacts of habitat disturbance will be minimized by placing the pipeline under an existing dirt road in fields that are dominated by vineyards and agricultural production

- Ground-dwelling animals could become trapped in uncovered trenches if the trenches were kept open at night or if suitable egress was not provided. Therefore, escape ramps will be employed.

- The construction site would be restored to pre-existing contours and re-vegetated after construction.

For project linears, the temporary construction and laydown area would remain along the 25- to 75-foot construction right-of-way during the course of construction. The laydown area would serve as the location for storing pipe and other pipeline construction materials. The EAEC plans to locate additional storage area in existing paved or graveled areas. Pipeline construction would take approximately 8 months and would occur from fall 2002 to spring 2003.

In addition, the applicant proposes the following (as stated in EAEC 2001a, page 8.2-28)***:***

Vegetation would be removed in the course of trenching along the pipeline. Most of the habitat disturbed would be annual grassland and weeds occurring along roadsides, but some agricultural fields could also be trenched. After construction, the trench would be back-filled with the excavated soil and restored to pre-construction conditions, both with respect to contour and vegetation.

Impacts to wildlife and special status species from linear corridor construction would be mitigated through the measures specified above, including pre-construction surveys, avoidance, and restoration. After mitigation, the habitat should provide the same support of wildlife as prior to linear installation.

Mitigation for Impacts from Transmission Lines

The applicant proposes to design and construct transmission lines within code to minimize the electrocution of large raptors (APLIC 1996 ; CEC 1999; EAEC 2001a). Upon implementation of the proposed mitigation impacts of the new transmission lines will be less than significant.

Mitigation for Cumulative Impacts

The applicant has not proposed to mitigate for cumulative impacts because they determined impacts to be insignificant (EAEC 2001a, page 8.2-29).

STAFF'S PREFERRED MITIGATION

In general, staff supports the aforementioned mitigation proposed by the applicant because the measures will prevent significant impacts from construction, operation, and maintenance, and will compensate (and minimize) for permanent and temporary impacts of habitat loss through habitat compensation. Staff proposes the following standard conditions, as originally put forth by the applicant:

- Hiring of a designated biologist (see Conditions of Certification **BIO-1, BIO-2** and **BIO-3**);
- Implementation of Worker Environmental Awareness Program (see Condition of Certification **BIO-4)**;
- Compliance with USFWS and CDFG permit requirements (see Conditions of Certification **BIO-5** and **BIO-6)**;
- Preparation of a BRMIMP (see Condition of Certification **BIO-7)**;
- Implementation of construction and operation mitigation measures (see Conditions of Certification **BIO-7**and **BIO-8)**; and
- Preparation of facility closure plans (for emergency and permanent closures) (see Condition of Certification **BIO-10**).

Staff also supports the proposed habitat mitigation strategy for addressing permanent and temporary habitat losses (see Condition of Certification **BIO-9**). The following discussion highlights specific mitigation issues, some of which require more information from the applicant in order to proceed and reach completion in the Final Staff Assessment.

Habitat Mitigation

In accordance with USFWS and CDFG requirements, the significant permanent and temporary losses of habitats used by special status species must be mitigated at both on-site and off-site locations (Gan 2001a; Larson 2001). Suitable off-site habitat mitigation parcels may be identified in Alameda, Contra Costa, or San Joaquin counties (Gan 2001a; Larson 2001). San Joaquin County is in the process of implementing a regional habitat conservation plan (HCP) that applies a “per-acre” mitigation fee to development projects. This strategy may not be feasible or reasonable and is not staff’s preferred mitigation for habitat loss.

Staff further proposes that both off-site habitat mitigation areas are protected in perpetuity and managed to enhance populations of special status species inhabiting the EAEC vicinity. The applicant has proposed to retain approximately 134 acres of agricultural lands surrounding the EAEC (on-site) for use in agriculture and for the benefit of wildlife, including kit fox and bird species (EAEC 2001v, Supplement B, page 3). The management plan for this on-site vegetation will be developed in consultation with the USFWS, CDFG, and Western. In addition, the implementation of a red fox control program may be required per recommendation of the USFWS and CDFG.

On October 10, 2001, staff received new information on the amount of acres to be permanently impacted. These changes resulted from the elimination of the evaporation ponds and other changes to the EAEC project (EAEC 2001v, page 3). Biology staff has used the following ratios for mitigation, understanding that the ratios might change depending on habitat quality (Larson 2001; EAEC data response 2 attachment BR-52-2).

- Permanent : 40 acres at mitigation ratio of 3:1 = 120 acres
- Temporary: 52.29 at mitigation ratio of 1.1:1 (using water pipeline 3E)= 57.52 acres

The applicant would be required to purchase the following acreages for permanent and temporary impacts. Based on these latest numbers, staff concludes that approximately 40 acres will be permanently impacted and that approximately 56.83 of acres will be temporarily impacted in addition to linear corridors affected by the water and gas pipelines and the transmission tower installation. Thus, total acreage required for mitigation may be approximately 177.5 (120+57.52) acres but would vary according to quality of the habitat acquired. The final acres to be mitigated will reflect additional information received and staff's consultation with the USFWS, CDFG, and Western (EAEC 2001u, page 3; EAEC 2001w, page 1).

The mitigation land will be owned in perpetuity for conservation and will need to be managed by a qualified natural land management organization to be approved in consultation with the USFWS, CDFG, and Western. Management of the mitigation land must be conducted with specific goals for enhancing special status plant species. The management plan will be developed in consultation with the USFWS, CDFG, and Western (see Condition of Certification **BIO-9**).

Avoidance and Minimization Measures to Protect Special Status Species

The applicant will be required to conduct pre-construction surveys for:

- Listed and sensitive plant species (i.e. big tarplant and showy Indian clover), which may grow along grassland portions of project linear features,
- Listed and sensitive animal species such as those listed in the **Biological Resources Table 1**.
- If sensitive species of plants or animal are detected, construction activities will avoid nests or habitat areas for the species according to USFWS and CDFG protocols. Noise levels and lighting will also be eliminated or minimized to avoid adverse impacts to sensitive species during construction.

Mitigation for Impacts to Native Fish

Biology staff is unable to determine appropriate mitigation at this time due to incomplete information and analysis. The increased diversion of freshwater from the Delta could potentially result in significant indirect and cumulative adverse impacts to native special status fish populations and their critical habitat (NMFS 2001a). However, as previously discussed, the analysis of water diversion levels is continuing, and biology staff requires new information from the applicant, DWR, and BBID. If it is determined by these agencies that the proposed water use will indeed divert increased amounts of water from the Delta, biology staff will conduct its analysis of impacts and associated mitigation in consultation with NMFS. If water diversions are deemed increased, the applicant would be required to consult again with NMFS (NMFS 2001a).

Mitigation for Landscaping and Visual Screening:

The applicant's proposed mitigation for visual impacts may inadvertently result in significant, adverse, and long-term biological impacts. Biology staff's preferred mitigation may result in unmitigated visual impacts. However, the proposed visual mitigation/landscaping may significantly impact species protected under the Federal Endangered Species Act. Accordingly, the USFWS and CDFG have expressed strong concerns about the adverse impacts caused by planting large trees and clusters of

dense vegetation. Such landscaping will likely result in unintentional damage to populations of special status species, especially the Federally Endangered San Joaquin kit fox. Thus, biology staff recommends that the visual screening landscape around the perimeter fence is designed with attention to the following:

- Use of native species, especially native grasses and forbs;
- Use of native shrubs and small trees such as Toyon (*Heteromyles arbutifolia*), Spicebush (*Calycanthus occidentalis*)(Hickman 1993).
- Avoidance of invasive and toxic plant species;
- Use of species that may provide food and cover for songbirds and native insects.
- Avoidance of plants whose size and growth pattern provide ground cover for mammalian predators of San Joaquin Kit Fox;
- Avoidance of plants that will likely to provide nesting opportunities for large raptors such as golden eagle because they too prey upon the San Joaquin kit fox;
- As such, the use of small, medium, sparsely planted trees may be acceptable; and
- An alternative may be to prohibit the use of any landscaping with trees or shrubs, if biological impacts of the landscape screening cannot be mitigated to less than significant levels according to USWFS and CDFG.

Alameda East County Area Plan contains policies, which state a preference for native species, which are suitable for the landscape and provide wildlife benefit. Based on the latest proposal submitted by the applicant (Environmental Vision 2001a), Biology staff concludes that the following tree species may be acceptable: *Populus nigra italica, Callistemon citrinus, Cercis occidentalis,* and *Crataegus phaenopyrum.* None of these species are native to the project area. However, the above species are non-invasive and can provide wildlife habitat without creating tall and dense tree and shrub groupings. The borders of the EAEC would not be planted uniformly with the same species. The tallest trees would be planted along the east side where long-range visual impacts are most significant. Future discussions with USFWS, CDFG, and the applicant will be needed before staff finalizes requirements regarding landscaping species composition and design around the EAEC.

Mitigation Measures for Operation and Maintenance

Routine operation, maintenance activities, and activities related to emergencies, may result in disturbances to vegetation and wildlife. The use of existing roads, appropriate driving speeds, and clear marking of sensitive areas will be required. The BRMIMP will provide detailed implementation procedures for minimizing construction, operation, and maintenance impacts to wildlife to less than significant levels. All employees will need to receive environmental awareness training so that they are knowledgeable about sensitive natural resources potentially occurring at EAEC project facilities, can ensure compliance with federal and state laws, and will ensure use of best management practices and procedures for protecting biological resources at all times (see Conditions of Certification **BIO-4**, **BIO-7,** and **BIO-8**).

Mitigation for Impacts from the Gas Supply Pipeline

Biology staff supports the selection of alternative 2A because it will not result in significant impacts to biological resources. Mitigation measures proposed by the applicant are designed to avoid and minimize impacts during construction, operation, and maintenance and are acceptable. Staff also requires that the applicant comply fully with any required CDFG and ACOE permit conditions.

Mitigation for Impacts from the Water Supply Pipeline

Staff supports selection of alternative 3E. Mitigation will include the applicant's proposed mitigation measures and full compliance with CDFG and ACOE permit conditions.

Mitigation for Impacts from the Recycled Water Pipeline

Staff concludes that the applicant's preferred pipeline is acceptable, upon implementation of pre-construction surveys, compliance with state and federal permits, habitat mitigation, and avoidance and mitigation measures. However, staff is concerned about the timeframe over which this pipeline will become feasible, due to questions regarding the water supply. Staff will require additional information, as the recycled water supply becomes more tangible and confirmed. As such, staff has not included acreage for habitat mitigation at this time.

Mitigation for Indirect Impacts

The indirect impacts of air pollution and noise will not need to be mitigated because there are no expected significant impacts to biological resources.

The indirect impacts of lighting, traffic and other potential adverse impacts from construction will be mitigated through specific mitigation practices listed in Condition of Certification and enforced with Worker Environmental Awareness Training (see Conditions of Certification **BIO-4** and **BIO-7**).

Mitigation measures for indirect impacts from avian collisions with stacks and transmission lines will be detailed and monitored in the BRMIMP. The applicant will also be required, as stipulated in the AFC, to implement designs for the transmission towers which prevent the electrocution of perching raptors per CEC (1999) and APLIC (1996) guidelines (see Conditions of Certification **BIO-7** and **BIO-8**).

Mitigation for Cumulative Impacts

Staff has determined that the cumulative impacts to biological resources are potentially significant. Staff requires more information and analysis from the applicant. The applicant did not propose mitigation for cumulative impacts. The implementation of alternative cooling technologies would eliminate EAEC's contribution to water diversions from the Delta. Such water diversions have potentially significant impacts to endangered and threatened fish species. Alternative cooling technologies such as the use of recycled water or dry cooling may be feasible alternatives for the EAEC to evaluate. Staff recommends evaluation and implementation of alternative cooling technologies because they would not require freshwater and prevent adverse impacts to special status fish. The mitigation for cumulative impacts will be further investigated in consultation with the USFWS, CDFG, NMFS, and Western for inclusion in the FSA.

COMPLIANCE WITH LORS

To be in compliance with applicable laws, ordinances, regulations and standards, the EAEC must obtain the following:

1) A Section 7 consultation and resulting Biological Opinion from the USFWS;
2) A Consistency Determination and/or take permit from CDFG;

3) A letter of consultation with the NMFS;
4) Any required CDFG Streambed Alteration Agreement; and
5) A U. S. Army Corps of Engineers Section 404 permit, if applicable.

These documents will identify mitigation measures required by each regulatory agency. For further information on these documents refer to Conditions of Certification **BIO-5** and **BIO-6**.

To help the project owner comply with laws, ordinances, regulations, and standards and the biological resource mitigation measures associated with this project, the applicant must designate a biological resource specialist (the Designated Biologist), prior to the beginning of any project-related ground disturbance, who is familiar with the biological resource issues of the project area. The Designated Biologist will help the project owner make certain that all mitigation measures are complied with during project construction and operation. For details about the roles and responsibilities of the Designated Biologist, see Conditions of Certification **BIO-2**, **BIO-3**, and **BIO-4**.

FACILITY CLOSURE

Sometime in the future, the EAEC facility will experience either a planned closure, or be unexpectedly (either temporarily or permanently) closed. When facility closure occurs, it must be done in such a way as to protect the environment and public health and safety. To address facility closure, an “on-site contingency plan” will be developed by the project owner and approved by the Energy Commission Compliance Project Manager (CPM)(See **General Conditions** section in **Facility Closure** and Biological Resources Condition of Certification **BIO-10**).

PLANNED OR UNEXPECTED PERMANENT FACILITY CLOSURE

The region surrounding the proposed project site is a mosaic of agricultural habitats and vernal pool, wetland habitats, which provide habitat for sensitive species (i.e. the San Joaquin kit fox, California tiger Salamander, California red-legged frog, Swainson’s hawk, white-tailed kite, and burrowing owl). Because the proposed project area currently provides habitat for these species, the facility closure plan needs to address habitat restoration measures to be implemented in the event of a planned or an unexpected permanent closure. Habitat restoration measures that should be addressed include such tasks as the removal of all power plant site structures and the immediate implementation of habitat restoration measures to re-establish native habitat types. In addition, planned or unexpected permanent facility closure may also trigger the removal of the transmission conductors, and possibly the entire transmission line, since birds are known to collide with transmission conductors.

UNEXPECTED TEMPORARY CLOSURE

In the event of an unexpected temporary closure, EAEC must ensure environmental safety and compliance with all BRMIMP conditions as well as those established in the **Soil and Water Resources** section in this Staff Assessment. In the event that the Energy Commission CPM decides that the facility is permanently closed, the above-mentioned facility closure measures need to be given careful consideration.

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

The proposed EAEC will result in significant adverse impacts to biological resources. These adverse impacts include permanent loss of 40 acres of cropland, cumulative impacts of habitat loss and fragmentation, as well as on-site impacts resulting from construction, operation, and maintenance during the lifetime of the EAEC facility. Careful selection of linear routes for gas and water pipelines will also avoid and minimized any adverse impacts. All potentially significant impacts are mitigable to less than significant levels using agency-approved habitat compensation and management, compliance with federal and state permits, administration of the Worker Environmental Awareness Program, implementation of avoidance and minimization measures, and implementation of the BRMIMP.

At present, the requirement that the applicant avoid adverse impacts from the proposed landscaping conflicts directly with mitigation required to minimize impacts to visual resources. However, because federally listed species may be harmed by the proposed landscaping, staff fully supports the position of the USFWS and CDFG that the originally proposed landscaping is unacceptable. The most recent landscaping proposal continues to be reviewed and discussed amongst the agencies, the applicant, and staff. Staff needs to receive further information from the applicant on the habitat mitigation and will consult with USFWS and CDFG in order to ensure that the mitigation determined in the FSA is sufficient.

Biology staff is concerned about the impacts of the proposed water diversions from the Delta on native special status fish. Biology staff seeks more convincing evidence that the proposed water diversions are not increased so that they will not significantly impact special status Delta fish. Consequently, biology staff will continue to confer with staff in Soils and Water Resources, DWR, and NMFS regarding the proposed water supply. Particular emphasis shall be placed upon analyzing cumulative impacts due to the other power plant projects proposed for the region. If water diversions are determined to be increased over existing levels, a second consultation with NMFS shall be required to ensure compliance with LORS (NMFS 2001a).

RECOMMENDATIONS

Staff needs additional information in order to complete its analysis of the EAEC. The additional information required includes:

- Completion of initiation of the Section 7 consultation with USFWS;
- Information confirming the status of the Delta water diversions as being increased or not increased over current levels;
- Additional information which completes evaluation of the impacts of air emissions; and
- Specific additional information regarding off-site mitigation for sensitive species, including acreage, and arrangements for purchase and management of the mitigation lands.

If the proposed project's water diversions are concluded to constitute an increase by Soil and Water Resources staff, DWR, and BBID, the applicant will need to complete a second consultation with NMFS regarding use of Delta water and impacts to special status Delta fish.

Staff cannot make a recommendation regarding the EAEC due to outstanding issues regarding project landscaping, habitat mitigation, and water use impacts to Delta fish. Staff has requested the needed information, and will continue consultations with the USFWS, CDFG, NMFS, and Western.

CONDITIONS OF CERTIFICATION

These conditions of certification are preliminary because more information is needed. As such they will be amended as needed for the Final Staff Assessment.

BIO-1 Site mobilization activities, including power plant site and all related facilities, (described as any ground disturbing activity other than allowed geotechnical work) shall not begin until an Energy Commission CPM approved Designated Biologist is available to be on-site.

Protocol: The Designated Biologist must meet the following minimum qualifications:

1. A 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. At least one year of field experience with biological resources found in or near the project area; and
4. an ability to demonstrate to the satisfaction of the CPM the appropriate education and experience for the biological resources tasks that must be addressed during project construction and operation.

If the CPM determines the proposed Designated Biologist to be unacceptable, the project owner shall submit another individual's name and qualifications for consideration. If the approved Designated Biologist needs to be replaced, the project owner shall obtain approval of a new Designated Biologist by submitting to the CPM the name, qualifications, address, and telephone number of the proposed replacement. No habitat disturbance will be allowed in any designated sensitive areas until the CPM approves a new Designated Biologist and the new Designated Biologist is on-site.

Verification: At least ninety (90) days prior to the start of any site mobilization activities, the project owner shall submit to the CPM for approval the name, qualifications, address, and telephone number of the individual selected by the project owner as the Designated Biologist. If a Designated Biologist is replaced, the information on the

proposed replacement as specified in the Condition must be submitted in writing at least ten (10) working days prior to the termination or release of the preceding Designated Biologist.

BIO-2 The CPM approved Designated Biologist shall perform the following during any site mobilization, construction and operation activities:

1. Advise the project owner's Construction Manager, supervising construction and operations engineer on the implementation of the biological resources Conditions of Certification;

2. Supervise or conduct mitigation, monitoring, and other biological resources compliance efforts, particularly in areas requiring avoidance or containing sensitive biological resources, such as wetlands and special status species; and

3. Notify the project owner and the CPM of any non-compliance with any biological resources Condition of Certification.

Verification: During site mobilization, ground disturbance, grading, construction, and operation, the Designated Biologist shall maintain written records of the tasks described above, and summaries of these records shall be submitted along with the Monthly Compliance Reports to the CPM. During project operation, the Designated Biologist shall submit record summaries in the Annual Compliance Report.

BIO-3 The project owner's Construction/Operation Manager shall act on the advice of the Designated Biologist to ensure conformance with the Biological Resources Conditions of Certification.

Protocol: The project owner's Construction/Operation Manager shall halt, if necessary, all construction or operation activities in areas specifically identified by the Designated Biologist as sensitive to assure that potential significant biological resource impacts are avoided.

The Designated Biologist shall:

1. Inform the project owner and the Construction/Operation Manager when to resume construction or operation, and

2. Advise the Energy Commission CPM if any corrective actions are needed or have to be instituted.

Verification: Within two (2) working days of a Designated Biologist notification of non-compliance with a Biological Resources Condition of Certification or a halt of construction or operation, the project owner shall notify the CPM by telephone of the circumstances and actions being taken to resolve the problem or the non-compliance with a condition. For any necessary corrective action taken by the project owner, a

determination of success or failure will be made by the CPM within five (5) working days 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.

BIO-4 The project owner shall develop and implement a CPM approved Worker Environmental Awareness Program in which each of its employees, as well as employees of contractors and subcontractors who work on the project or related facilities (including any access roads, storage areas, transmission lines, water and gas lines, etc) during site mobilization, construction and operation, are informed about sensitive biological resources associated with the project.

The Worker Environmental Awareness Program must:

1. Be developed by the Designated Biologist and consist of an on-site or training center presentation in which supporting written material is made available to all participants;

2. Discuss the locations and types of sensitive biological resources on the project site and adjacent areas;

3. Present the reasons for protecting these resources, including the penalties for violating laws protecting the resources;

4. Present the meaning of various temporary and permanent habitat protection measures; and

5. Identify whom to contact if there are further comments and questions about the material discussed in the program.

The specific program can be administered by a competent individual(s) acceptable to the Designated Biologist.

Each participant in the on-site Worker Environmental Awareness Program shall sign a statement declaring that the individual understands and shall abide by the guidelines set forth in the program materials. The person administering the program shall also sign each statement.

Verification: At least forty five (45) days prior to the start of any site mobilization, the project owner shall provide two (2) copies of the Worker Environmental Awareness Program and all supporting written materials prepared by the Designated Biologist and the name and qualifications of the person(s) administering the program to the CPM for approval. The project owner shall state in the Monthly Compliance Report 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. The signed statements for the construction phase shall be kept on file by the project owner and made available for examination by the CPM for a period of at least six (6) months after the start of

commercial operation. During project operation, signed statements for active project operational personnel shall be kept on file for six (6) months, following the termination of an individual's employment.

BIO-5 The project owner shall acquire an Incidental Take Permit from the California Department of Fish and Game (CDFG) (per Section 2081(b) of the California Endangered Species Act), or a Determination of Consistency with the USFWS Biological Opinion. The project owner will implement the permit terms and conditions.

Verification: At least twenty (20) days prior to the start of any site mobilization activities the project owner shall submit to the CPM a copy of the final CDFG Incidental Take Permit. Permit terms and conditions will be incorporated into the Biological Resources Mitigation Implementation and Monitoring Plan.

BIO-6 The project owner shall provide final copies of the Biological Opinion persuant to Section 7 of the Federal Endangered Species Act obtained from the U. S. Fish and Wildlife Service. The project owner will implement the terms and conditions contained in the Biological Opinion.

Verification: At least twenty (20) days prior to the start of any site mobilization activities the project owner shall submit to the CPM a copy of the Biological Opinion. Permit terms and conditions will be incorporated into the Biological Resources Mitigation Implementation and Monitoring Plan.

BIO-7 The project owner shall submit to the CPM for review and approval a copy of the Biological Resources Mitigation Implementation and Monitoring Plan (BRMIMP) and shall implement the measures identified in the plan. Any changes to the BRMIMP must be made in consultation with Energy Commission staff, CDFG and the USFWS.

The final BRMIMP shall identify:

1. All biological resources mitigation, monitoring, and compliance measures stipulated by the project owner and contained in all of the Conditions of Certification and other mitigation requirements**;**

2. All sensitive biological resources to be impacted, avoided, or mitigated by project construction, operation and closure;

3. All mitigation measures provided in the USFWS Biological Opinion and the CDFG 2081(b) Permit;

4. All provisions specified in a CDFG Streambed Alteration Agreement Notification, if applicable;

5. All required mitigation measures for each sensitive biological resource;

6. Required habitat compensation strategy, including provisions for acquisition, enhancement, and management for any temporary and permanent loss of sensitive biological resources;

7. A detailed description of measures that will be taken to avoid or mitigate temporary disturbances from construction activities;

8. All locations, on a map of suitable scale, of laydown areas and areas requiring temporary protection and avoidance during construction;

9. Aerial photographs of all areas to be disturbed during project construction activities - one set prior to any site mobilization disturbance and one set subsequent to completion of mitigation measures. Include planned timing of aerial photography and a description of why times were chosen;

10. Duration for each type of monitoring and a description of monitoring methodologies and frequency;

11. Performance standards to be used to help decide if/when proposed mitigation is or is not successful;

12. All performance standards and remedial measures to be implemented if performance standards are not met;

13. A discussion of biological resources related facility closure measures; and

14. A process for proposing plan modifications to the CPM and appropriate agencies for review and approval.

Verification: At least sixty (60) days prior to start of any site mobilization activities, the project owner shall provide the CPM with two (2) copies of the BRMIMP for this project, and provide copies to the CDFG and the USFWS. The CPM, in consultation with the CDFG and the USFWS, will determine the plan's acceptability within forty-five (45) days of receipt. The project owner shall notify the CPM no less than five (5) working days before implementing any modifications to the BRMIMP to obtain CPM approval.

Within thirty (30) days after completion of project construction, the project owner shall provide to the CPM, for review and approval, a written report identifying which items of

the BRMIMP have been completed, a summary of all modifications to mitigation measures made during the project's construction phase, and which mitigation and monitoring plan items are still outstanding.

BIO-8 The project owner will implement the mitigation measures identified below unless the mitigation measures conflict with mitigation required by the U. S. Fish and Wildlife Biological Opinion. The project owner will incorporate these mitigation measures into the BRMIMP and ensure that all employees implement these measures at all times (BIO-7).

Protocol: The project owner will:

1. Site transmission line poles, access roads, pulling sites, and storage and parking areas to avoid sensitive resources whenever possible.
2. Design and construct transmission lines and poles to reduce the likelihood of electrocutions of large birds.
3. Monitor for avian electrocution and collisions for 12 months to determine if mitigation, such as the installation of bird-flight diverters, is necessary. The monitoring plan will be included in the BRMIMP and developed in consultation with the USFWS and CDFG.
4. Conduct construction monitoring of the pipeline route that passes through or adjacent to sensitive habitats.
5. Avoid all wetland and vernal pool habitats.
6. Avoid excavation and ground disturbing activities during hibernation, breeding, or rest periods for burrowing animals such as kit fox and burrowing owl.
7. Use of daytime construction at all drainages and drains in order to avoid impacts to special-status reptiles and mammals.
8. Define construction area boundaries clearly with stakes, flagging, silt fencing, and/or rope or cord to minimize inadvertent degradation or loss of adjacent habitat during facility construction/modernization.
9. Restrict equipment storage to designated construction zones or areas that are currently not considered sensitive species habitat.
10. Enforcement of a speed limit of 20 miles/hour on-site.
11. Avoidance of rodenticides on-site and along linears.
12. Prescribe use of low toxicity herbicides to control weeds on-site and along linears.
13. Implement dust control measures during construction and operation.

14. Prohibition of pets on-site.

15. Prohibition of firearms on-site.

16. Immediate removal of hazardous debris and waste on-site and along linears.

17. Implementation of an erosion prevention and control (see **Soil and Water Resources** section) on-site and along linears.

18. Restrict traffic access to existing roads, designated access roads, construction storage and staging areas, and parking areas.

19. Fence and provide wildlife escape ramps for construction areas that contain steep-walled holes or trenches. If necessary ramps and side exits will be placed in the trench every 0.25 km. Fence will be hardware cloth or similar materials that are approved by USFWS and CDFG.

20. Inspect open trenches for wildlife each morning prior to start of daily construction activities. Any wildlife observed will be allowed to escape on its own if possible prior to commencement of construction. Otherwise, the Designated Biologist will contact the appropriate agency for assistance.

21. Inspect all construction pipes, culverts, or similar structures with a diameter of 4-inches or greater for sensitive species (such as kit foxes) prior to pipe burial. Pipes to be left in trenches overnight will be capped.

22. Report all inadvertent deaths of sensitive species to the appropriate project representative. Injured animals will be reported to CDFG, and the project owner will follow instructions that are provided by CDFG.

23. Revegetate and maintain all linears, construction, staging, temporary parking, and equipment storage areas with native valley-grassland plant species.

Verification: All mitigation measures and their implementation methods will be included in the BRMIMP (**BIO-7**). Two (2) copies of the CPM approved BRMIMP must be provided to the CPM five (5) days prior to site mobilization and copies provided to the CDFG and the USFWS.

BIO -9 To compensate for temporary and permanent impacts to sensitive wildlife habitat, the project owner shall purchase approximately 180 acres of suitable compensation habitat. Title for compensation habitat shall be transferred into an account managed by a qualified and approved natural land management group or agency to be managed in perpetuity as a nature preserve. The project owner shall also provide an endowment, including land purchase, administrative costs, and habitat enhancement funds, to ensure the perpetual management of the compensation habitat. Selection of property and management procedures must be approved by the CPM in consultation with the USFWS and CDFG.

Verification: Not less than fifteen (15) days prior to the start of any site or related facility mobilization activities the project owner shall provide a copy of the check to the CPM. The project owner shall also provide a letter from the land management organization stating the amount of funds received.

BIO-10 The project owner will incorporate into the planned permanent or unexpected permanent closure plan measures that address the local biological resources.

The planned permanent or unexpected permanent closure plan will address the following biological resources related mitigation measures:

1. Removal of transmission conductors when they are no longer used and useful;

2. Removal of all power plant site facilities and related facilities;

3. Measures to restore wildlife habitat to promote the re-establishment of native plant and wildlife species; and

4. Revegetation of the plant site and other disturbed areas utilizing appropriate seed mixture.

Verification: At least twelve (12) months (or a mutually agreed upon time) prior to the commencement of closure activities, the project owner shall address all biological resources related issues associated with facility closure in a Biological Resources Element. The Biological Resources Element will be incorporated into the Facility Closure Plan and include a complete discussion of the local biological resources and proposed facility closure mitigation measures.

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CULTURAL RESOURCES

Roger Mason

INTRODUCTION

The cultural resources section identifies potential impacts of the proposed East Altamont Energy Center regarding cultural resources, which are defined under state and federal law in the Laws Ordinances Regulations and Standards (LORS) section of this staff assessment. The primary concern in cultural resource analysis for this project is to ensure that all potential impact are identified and that conditions are set forth that ensure no significant adverse impacts will occur under the National Environmental Policy Act and that impacts are mitigated below a level of significance under the California Environmental Quality Act.

Staff provides a cultural overview of the project, as well as a California Environmental Quality Act (CEQA) criteria based analysis and a National Historic Preservation Act analysis that assesses potential project related impacts. If cultural resources are identified, staff determines whether there may be a project related impact to identified resources and if the resource is eligible for the California Register of Historic Resources (CRHR) or the National Register of Historic Places (NRHP). If eligible, staff recommends mitigation that ensures no significant impacts will occur and that will reduce impacts to the cultural resource to a less than significant level.

There is always a potential that a project may impact a previously unidentified resource or impact an identified historical resource in an unanticipated manner. Staff therefore recommends procedures in the conditions of certification that mitigate these potential impacts.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

The following laws, ordinances, regulations, standards, and policies apply to the protection of cultural resources in California. Projects licensed by the Energy Commission are reviewed to ensure compliance with these laws.

FEDERAL

- National Environmental Policy Act (NEPA): Title 42, United States code, section 4321et seq., requires federal agencies to consider potential environmental impacts of projects with federal involvement and to consider appropriate mitigation measures.
- 36 C.F.R. Section 61 Federal Guidelines for Historic Preservation Projects: The US Secretary of the Interior has published a set of Standards and Guidelines for Archaeology and Historic Preservation. These are considered to be the appropriate professional methods and techniques for the preservation of archaeological and historic properties. The State Historic Preservation Office refers to these standards in its requirements for selection of qualified personnel and in the mitigation of potential impacts to cultural resources on public lands in California.

- National Historic Preservation Act of 1966, as amended (Title16 United States Code 470). This act expresses the general policy of the federal government that supports and encourages the preservation of prehistoric and historic resources for present and future generations. It established the National Register of Historic Places, established the President's Advisory Council on Historic Preservation, established procedures for actions taken by federal agencies that may affect historic resources, and established a fund for preservation. Pertinent to this project, section 106 of this act requires federal agencies to take into account the effects of their undertakings on historic properties through consultations beginning at the early stages of project planning.
- 36 Code of Federal Regulations Part 800. These procedures of the Advisory Council on Historic Preservation, most commonly referred to as the section 106 process, established a process to ensure that federal agencies have taken into account the impacts of their undertakings on significant cultural resources. An agency is strongly encouraged to consult with various parties, including the State, private parties, and Indian Tribes as they determine the presence or absence of cultural resources, the eligibility of resources for nomination to the National Register of Historic Places (NRHP), and the effect the federal action may have on those resources. Very similar criteria and procedures are used by the State of California in identifying cultural resources eligible for listing in the California Register of Historical Resources.
- Executive Order 11593, "Protection and Enhancement of the Cultural Environment," May 13, 1971 (36 Federal Register 8921), orders the protection and enhancement of the cultural environment through providing leadership, establishing state offices of historic preservation, and developing criteria for assessing resource values.
- American Indian Religious Freedom Act; Title 42, United States Code, section 1996 protects Native American religious practices, ethnic heritage sites, and land uses.
- Native American Graves Protection and Repatriation Act of 1990; Title 25, United States Code section 3001, et seq. This act provided for the repatriation of certain items from the federal government and certain museums to the native groups to which they once belonged. The act also define "cultural items," "sacred objects," and "objects of cultural patrimony"; and it establishes a means for determining ownership of these items. However, the provisions for repatriation only apply to items found on federal lands or Indian lands.
- National Environmental Policy Act of 1969 (NEPA; Title 42, United States Code, sections 4321-4347). This act requires federal agencies to consider impacts of their projects on the human environment, whether the action is funded or permitted by the agency. Part of the human environment includes the cultural environment.
- 10 Code of Federal Regulations Part 1021. These are the procedures of the Department of Energy that implement the provisions of the National Environmental Policy Act.

STATE

- The term "cultural resource" is used broadly to include the following categories of resources that are identified pursuant to California Code of Regulations, Title 14, section 4852. A list of categories of potential resources appears below.

(a) Types of resources eligible for nomination:

(1) Building. A resource, such as a house, barn, church, factory, hotel, or similar structure created principally to shelter or assist in carrying out any form of human activity. 'Building' may also be used to refer to an historically and functionally related unit, such as a courthouse and jail or a house and barn;

(2) Site. A site is the location of a significant event, a prehistoric or historic occupation or activity, or a building or structure, whether standing, ruined, or vanished where the location itself possesses historical, cultural, or archeological value regardless of the values of any existing building, structure, or object. A site need not be marked by physical remains if it is the location of a prehistoric or historic event, and if no buildings, structures, or objects marked it at that time. Examples of such sites are trails, designed landscapes, battlefields, habitation sites, Native American ceremonial areas, petroglyphs, and pictographs;

(3) Structure. The term 'structure' is used to describe a construction made for a functional purpose rather than creating human shelter. Examples of structures included mines, bridges and tunnels;

(4) Object. The term 'object' is used to describe those constructions that are primarily artistic in nature or are relatively small in scale and simply constructed, as opposed to a building or a structure. Although it may be movable by nature or design, an object is associated with a specific setting or environment. Objects should be in a setting appropriate to their significant historic use, role, or character. Objects that are relocated to a museum are not eligible for listing in the California Register. Examples of objects include fountains, monuments, maritime resources , sculptures, and boundary markers; and

(5) Historic district. Historic districts are unified geographic entities which contain a concentration of historic buildings, structures, objects, or sites united historical, culturally, or architecturally. Historic districts are defined by precise geographic boundaries. Therefore, districts with unusual boundaries require a description of what lies immediately outside the area in order to define the edge of the district and to explain the exclusion of adjoining areas. The district must meet at least one of the criteria for significance discussed in Section 4852 (b)(1)-(4) of this chapter.

When a cultural resource is determined to be historically significant or significant in the architectural, engineering, scientific, economic, agricultural, educational, social, political, military, or cultural annals of California, it may be considered to be an "historical resource" and eligible for inclusion in the CRHR.

If the archaeological resource does not meet the criteria for an historical resource, it may be assessed to determine whether it meets the criteria of a unique resource as defined in the Public Resources Code.

- Public Resources Code, section 5020.1 defines several terms, including the following:
  (j) “Historical resource” and (q) “Substantial adverse change” means demolition, destruction, relocation, or alteration such that the significance of an historical resource would be impaired.
- Public Resources Code, section 5024.1 establishes a California Register
- Public Resources Code, section 5097.5 states that any unauthorized removal or destruction of archaeologic or paleontologic resources on sites located on public land is a misdemeanor. As used in this section, “public lands” means lands owned by, or under the jurisdiction of, the state, or any city, county, district, authority, or public corporation, or any agency thereof.
- Public Resources Code, section 5097.98 defines procedures for notification of discovery of Native American artifacts or remains and for the disposition of such materials.
- Public Resources Code, section 5097.99 prohibits obtaining or possessing Native American artifacts or human remains taken from a grave or cairn and sets penalties for these actions.
- Public Resources Code, section 5097.991 states that it is the policy of the state that Native American remains and associated grave artifacts shall be repatriated.
- Public Resources code, section 21000, et seq, California Environmental Quality Act (CEQA), requires the analysis of potential environmental impacts of proposed projects and requires application of feasible mitigation measures.
- Public Resources Code, section 21083.2 states that if a project may affect a resource that has not met the definition of an historical resource set forth in section 21084, then the lead agency may determine whether a project may have a significant effect on ”unique” archaeological resources; if so, an EIR shall address these resources.; If a potential for damage to unique archaeological resources can be demonstrated, the lead agency may require reasonable steps to preserve the resource in place. Otherwise, mitigation measures shall be required as prescribed in this section. The section discusses excavation as mitigation; limits the applicant’s cost of mitigation; sets time frames for excavation; defines “unique and non-unique archaeological resources”; and provides for mitigation of unexpected resources.
- Public Resources Code, section 21084.1 indicates that a project may have a significant effect on the environment if it causes a substantial adverse change in the significance of a historic resource; the section further defines a “historical resource” and describes what constitutes a “significant” historical resource.
- CEQA guidelines, Title 14, California Code of Regulations, section 15126.4 “Consideration and Discussion of Mitigation Measures Proposed to Minimize Significant Effects” sub-section (b) discusses impacts of maintenance, repair, stabilization, restoration, conservation, or reconstruction of a historical resource. Subsection (b) also discusses mitigation through avoidance of damaging effects on

any historical resource of an archaeological nature, preferably by preservation in place, or by data recovery through excavation if avoidance or preservation in place is not feasible. Data recovery must be conducted in accordance with an adopted data recovery plan.

- CEQA Guidelines, Title 14, California Code of Regulation, section 15064.5 “Determining the Significance of Impacts to Archaeological and Historical Resources”. Subsection (a) defines the term “historical resources.” Subsection (b) explains when a project may be deemed to have a significant effect on historical resources and defines terms used in describing those situations. Subsection (c) describes CEQA’s applicability to archaeological sites and provides a bridge between the application of the terms "historical” resources and a “unique” archaeological resource.
- CEQA Guidelines, Title 14 California Code of Regulations, section 15064.7 “Thresholds of Significance.” This section encourages agencies to develop thresholds of significance to be used in determining potential impacts and defines the term “cumulatively significant.”
- California Penal Code, section 622.1/2. Anyone who willfully damages an object or thing of archaeological or historic interest can be found guilty of a misdemeanor.
- California Health and Safety Code, section 7050.5. If human remains are discovered during construction, the project owner is required to contact the county coroner.
- Public Resources Code, section 5097.98. If the county coroner determines that the remains are Native American, the coroner is required to contact the Native American Heritage Commission, which is then required to determine the “Most Likely Descendant” to inspect the burial and to make recommendations for treatment or disposition of the remains and any associated burial items.

LOCAL

San Joaquin County

The San Joaquin County General Plan includes a goal for protection of architectural, historical, archaeological, and cultural resources (San Joaquin County 1992). The General Plan contains policies for the identification, protection, and preservation of significant archaeological and historical resources, reuse of architecturally or historically significant buildings, and promotion of public awareness and support for historic preservation. These policies are implemented through County Museum programs for public education, historic inventories, and promotion of National Register and California Register nominations of historic structures. The Planning Department is required to develop historic preservation regulations.

Contra Costa County

The Contra Costa General Plan contains a goal to identify and preserve important archaeological and historic resources (Contra Costa County 1996). There are policies for preservation and protection of buildings, structures, and areas with historic or archaeological significance, use of compatible design for development of areas adjacent to areas of historic significance, and balancing multiple land use with protection of

archaeological resources in the Southeast County Area. The Planning Agency will develop an archaeological sensitivity map and procedures for protection of archaeological resources encountered during construction. Use of the State Historic Building Code is encouraged and property owners are encouraged to nominate their historic properties for the National Register of Historic Places and the California Register of Historical Resources and to make use of tax incentives.

East Alameda County

The East Alameda County General Plan (Alameda County 1994) contains a goal to protect cultural resources from development. Policies include preservation and identification of significant archaeological and historical resources and planning development to avoid cultural resources. Procedures for protection of archaeological sites include requiring records searches and surveys and halting construction if archaeological sites are found. Renovation or relocation are considered appropriate measures for preservation of historic structures. Proposed demolition of historic structures must be reviewed by qualified professionals.

ENVIRONMENTAL SETTING

The power plant property is located in the northeast corner of Alameda County and project linears (routes for gas, water, and reclaimed water) extend into Contra Costa and San Joaquin Counties. The nearest cities are Livermore, about 12 miles to the southwest, and Tracy, about eight miles to the southeast. The project area is located on the west side of the San Joaquin Valley about 20 miles southeast of the confluence of the San Joaquin and Sacramento Rivers (the Delta). The Old River, a tributary of the San Joaquin River, flows northwestward along the western margin of the San Joaquin Valley about 1.5 miles east of the project area. Hills of the Diablo Range lie to the west of the project area. The project area was probably originally covered by grassland with marsh and wetlands along the Old River to the east. The extensive wetlands of the San Joaquin River delta were located nearby to the north. The wetlands areas to the east and north were known historically as the " Great Tule Swamp" (EAEC 2001s:6). Currently, land use is agricultural and little, if any, native vegetation remains. The climate is mild with warm, dry summers characterized by an almost complete absence of rain, and mild winters with relatively light rains. In the valley the temperature averages below thirty two than fifteen days per year where the temperature falls to thirty-two degrees or less. The average period between the last frost of spring and the first frost of fall is more than 7 1/2 months (Simonds). The average annual precipitation is 12 inches.

The power plant property is just south of the Clifton Court Forebay, the reservoir at the beginning of the California Aqueduct. The California Aqueduct is about 2 miles west of the power plant property and the Delta Mendota Canal is directly west of the power plant property. Some linear routes cross the Delta Mendota Canal. Mountain House Creek drains a portion of the Diablo Range and flows eastward across the southern part of the project area to the Old River. The project area is underlain by alluvium and the elevation at the site of the proposed power plant is about 40 feet. The project area is rural and land uses are primarily agricultural.

Refer to the **PROJECT DESCRIPTION** section of this Preliminary Staff Assessment for additional information and maps of the project development region and the project area.

PREHISTORIC SETTING

The prehistory of the northern San Joaquin Valley is not well known. Few sites have been investigated and most of these date to the Late Prehistoric Period. Although many sites from earlier periods are likely buried under later Holocene alluvium (of considerable depth in the Central Valley), a few sites from the Early Period (Fluted Point Tradition) and Middle Period (Windmiller Pattern) have been found in Central Valley locations (Moratto 1984). The Windmiller Pattern (4,750 to 2,000 yrs. Before Present [BP] south of the Delta area) is characterized by the use of large dart points for hunting, a trident spear and hooks for fishing, mortars and pestles (indicating acorn processing), ground and polished charmstones, baked clay artifacts, and marine shell beads and ornaments (Moratto 1984:201-203).

Terrestrial animals and fish appear to have been more important sources of food compared to seeds and acorns. After 2,000 BP the Late Period in the Central Valley is represented by the Augustine Pattern. The archaeological record indicates intensive use of acorns, fishing, hunting (using the bow and arrow), large, dense populations living in villages throughout most of the year, highly developed exchange systems, and social stratification (indicated by variability in grave goods), and elaborate ceremonialism (Moratto 1984:211). The later archaeological sites appear to reflect the same settlement and subsistence systems practiced by the Northern Valley Yokuts who occupied the area when the Spanish arrived in California. Most residential sites are located on low mounds near rivers.

ETHNOGRAPHIC BACKGROUND

The project area is in territory occupied by the Native American group known to the Spanish and twentieth century ethnographers as the Northern Valley Yokuts. The northern San Joaquin Valley was originally covered by sloughs and marshes along the San Joaquin River. The Northern Valley Yokuts obtained fish and waterfowl from the river and marshes. Grass and tule seeds were important plant foods. Acorns from the valley oaks were also collected. The Yokuts lived in permanent villages on mounds along the river, although gathering parties left the villages seasonally to collect seeds and acorns. They were organized in territorial tribelets of up to 300 people (Wallace 1978). The closest Yokuts village to the project area was probably the village known as Pescadero located on Union Island (east of the project area on the other side of Old River about a mile away from the end of the reclaimed water pipeline route). It was visited by the Spanish in 1810 (EAEC 2001s:11). Most native inhabitants in the vicinity of the project area were taken to Mission San Jose in the 1810s. Native populations were greatly reduced as a result of exposure to European diseases to which they had no immunity. After the missions were closed by the Mexican government in the 1830s, the few remaining Native Americans worked on cattle ranches in the area.

HISTORIC SETTING

Spanish missionaries began their exploration of California and development of the missions in 1769, starting in San Diego and ending with the missions in San Rafael and Sonoma, in 1823. Mission San Francisco and the San Francisco Presidio (military post)

were established in 1776. The closest mission to the project area was Mission San Jose, founded in 1797 (Beck and Haase 1974:19). After Mexico became independent from Spain, the missions were closed by the Mexican government in the early 1830s. Former mission lands were granted to soldiers and other Mexican citizens for use as cattle ranches. The El Pescadero land grant was granted in 1843 to Antonio M. Pico and was located along the Old River east of the project area (EAEC 2001s:11). A small portion of the reclaimed water pipeline route is within the boundaries of the El Pescadero land grant, as surveyed by the General Land Office. Ranching continued during the American period that began when the Treaty of Guadalupe Hidalgo was signed between Mexico and the United States in 1848. The Gold Rush of 1849 brought large numbers of Anglo-Americans to the area, resulting in the rapid expansion of San Francisco which became the commercial entrepot for the region.

Other towns in the bay area, such as Oakland and San Jose, developed rapidly after the arrival of the transcontinental railroad in 1869. The bay area towns provided commercial, warehousing, financial, and manufacturing services for the agricultural and mining areas further east. Agricultural use of the Central Valley was promoted by completion of the Southern Pacific Railroad along the eastern side of the valley in 1876. Stockton, located east of the project area along the railroad, became a grain shipping center.

In the project area agriculture and coal mining began in the 1860s. Grain and coal were shipped via the Old River to the bay area by riverboat from the town of Wicklund, also known as Mohr's Landing. Mr. Wicklund and Mr. Mohr were landowners in the area and Mohr operated a ferry crossing the Old River. The town of Wicklund was located on the southwest side of the Old River near the proposed terminus of the reclaimed water line route. Wicklund had a hotel, blacksmith shop, warehouse, and coal bunkers during the 1860s (Baker et al. 1991).

Completion of the Central Pacific Railroad line from Stockton to Oakland through Tracy and Ellis in 1869/1870 and the decline of coal production caused some people to leave Wicklund and move to Ellis on the railroad to the south. The town of Wicklund continued to exist for another ten years until the Northern Railway built a rail line much closer to Wicklund along the western side of the San Joaquin Valley from Martinez to Tracy in 1878. In 1880 this line was leased to the Central Pacific Railroad for a period of five years (Commissioner of Railroads 1883:15). The line was later acquired by the Southern Pacific Railroad. At this time Wicklund was abandoned and the new town of Bethany was founded along the rail line on land owned by Mohr.

Other land in the project area was originally owned by Charles McLaughlin, a contractor for the railroad who received land from the railroad in return for his services (EAEC 2001s:13). Mountain House was another nineteenth century settlement near the project area (EAEC 2001s:13). It was located at the intersection of Mountain House Road and Grant Line Road near Mountain House Creek about three miles south of the power plant property.

Large water conveyance systems that carry water southward from the Delta were built in the mid-twentieth century. The Delta Mendota Canal begins just north of the project area at the Old River and runs south through the project area on its way to the Mendota

Pool near Fresno. Water is pumped uphill to an aqueduct at the Tracy Pumping Station in the project area near the intersection of Kelso Road and Mountain House Road. Electricity is supplied to the pumping station by the adjacent Tracy Substation and associated transmission lines operated by the Western Area Power Administration. The transmission lines originate at power plants near Lake Shasta (EAEC 2001e, page 6). The Delta Mendota Canal and the associated pumping station and substation were built between 1946 and 1949 by the Morrison-Knudsen Company and the M.H. Hasler Construction Company under contract to the Bureau of Reclamation (Stene 1994). The California Aqueduct carries water to southern California. It is located just outside the project area to the west and was built in the 1960s (EAEC 2001e, page 6).

RESOURCES INVENTORY

Literature and Records Search

Prior to preparation of the AFC, the applicant conducted a cultural resources literature search and reviewed site records and maps for the project area in Alameda and Contra Costa Counties at the Northwest Information Center of the California Historic Resources Information System (CHRIS) located at Sonoma State University in Rohnert Park. A second records search was performed for the portion of the project area in San Joaquin County at the Central California Information Center located at Stanislaus State University in Turlock. The records searches included an area one mile in radius around the power plant site and the project linear routes.

Information from the CHRIS indicated that there have been 54 previous cultural resources investigations within one mile of the project area. However, only portions of the area to be impacted by the project and its associated linears are shown by the Information Centers' records as areas that have been surveyed prior to the surveys performed for the East Altamont Energy Center. The power plant property, the water line route between Mountain House Road and Bruns Road, and the gas line route on Kelso Road were not previously surveyed.

Site records and maps obtained by the applicant from the Information Centers indicate that the only previously recorded prehistoric cultural resources in the project vicinity consist of two archaeological sites and two isolated artifacts. One of the archaeological sites (CA-ALA-456) consists of a rockshelter with four associated bedrock mortars. No midden or artifacts were observed. The site area was heavily impacted by construction of the California Aqueduct and the Delta Pumping Plant. The site is within one mile of the end of the gas line route.

The other archaeological site (P-39-000254) is located in San Joaquin County along Mountain House Creek about 0.3 mile northeast of the reclaimed water line route. Little is known about this site. It was destroyed by land leveling for agriculture before it could be recorded by archaeologists. The only information available about the site is that two white chert spear points were collected from the surface of a beet field by a Mr. Barr. His artifact collection is at the Phoebe Hearst Museum of Anthropology at the University of California, Berkeley. Two isolated cores (P-39-000370 and P-39-000371) were recorded nearby. In addition, flakes and bone have been noted, but not recorded, in the same area along the creek. Although none of these prehistoric archaeological

resources will be impacted by construction of the reclaimed water line, the presence of several resources along Mountain House Creek indicates that this area is sensitive for prehistoric archaeological resources.
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Cultural resources from the historic period have been recorded in the vicinity of the project area, but only in San Joaquin County near the route of the reclaimed water line. It is likely that similar historical resources exist in Alameda and Contra Costa Counties, but much less land has been surveyed in the project vicinity and it appears that the surveyors were only focusing on prehistoric resources.

Four complexes of historic structures and two historic archaeological sites have been recorded within one half mile of the reclaimed water line route. The structure complexes consist of farmsteads with houses, barns, tankhouses, and other outbuildings. P-39-000366 appears to date from the 1880s and is located on the other side of the railroad track from the reclaimed water line route along Byron-Bethany Road near its intersection with Kelso Road. P-39-000367 appears to date from the 1910s and is located about one half mile northeast of Byron-Bethany Road near Mountain House Creek. P-39-000368 appears to date from the 1920s and is located near Mountain House Creek southwest of Byron-Bethany Road. P-39-000368 appears to date from the 1910s and is located southwest of Byron-Bethany Road near its intersection with Henderson and Bethany Roads. The reclaimed water line route does not pass through any of these historic resources.

One of the two historic archaeological sites, P-39-000345, represents a former farmstead complex that is no longer standing. The site consists of a scatter of bottle glass and ceramic fragments. Historic maps indicate the farmstead was built sometime between 1914 and 1943 (Hall and Smith 1991). The northern boundary of the site is 5 to 10 meters from the south side of Bethany Road (the route of the reclaimed water line in this area). The other historic archaeological site (P-39-000343) is the town site of Wicklund, located 75 meters west of the terminus of the reclaimed water line route. Material remains consist of a scatter of bottle glass and ceramic fragments (Baker et al. 1991). The reclaimed water line route does not pass through either of these historic resources, but comes within 5 to 10 meters of P-39-000345.

Although not recorded as an archaeological site, a historic map (Gilbert 1879) shows the location of the town of Bethany near the intersection of Byron-Bethany Road and Henderson and Bethany Roads on the southwest side of the railroad. The route of the reclaimed water line in Byron-Bethany Road and Bethany Road passes through or very near the town site.

There are several linear water conveyance features in the project area. The Westside Irrigation District's Main Drain (P-39-000470) begins at the intersection of Bethany and Wicklund Roads and runs southeast for 2.83 miles. It is about 15 feet deep and 35 feet wide and was built between 1926 and 1928, according to the record form. The gas line route and the water line route cross the Delta Mendota Canal which was constructed in the late 1940s (Stene 1994). The Tracy Pumping Station and the Tracy Substation are part of the infrastructure of the Delta Mendota Canal and are located north of Kelso Road and west of Mountain House Road. Other linear resources of historic age are discussed in the Field Surveys section.

The applicant provided an inventory of historic properties within ½ mile of the proposed project and associated linear components (excluding the recycled water line). The applicant reviewed aerial and ground photographs of the project area and identified 114 houses, structures, and linear resources, such as power lines, roads, and canals. They estimated the date of construction for homes and determined the effective age (when the building was last remodeled) by the façade and appearance of the buildings. No historical research was performed. The inventory provided the location of buildings and structures in relation to roads (no addresses), the approximate age, and potential eligibility for listing as a historic resource (EAEC 2001v, p.2). They concluded that all structures and linear resources within ½ mile of the power plant site, the water line route, and the gas line route are less than 45 years old and are not eligible for the CRHR nor the NRHP. This conflicts with the results of a field survey performed by a consultant to the Energy Commission (see next section).

Field Surveys

The applicant performed an intensive pedestrian survey (archaeological) of the property proposed for the East Altamont Energy Center and the associated linear routes, including the gas line route, the water line route (EAEC 2001s:15-18), and the reclaimed water line route (EAEC 2001e:5). The survey of the power plant property was performed by walking parallel 20 meter transects. An area 75 feet wide on each side of the centerline of the linear routes was surveyed by walking a sinuous or meandering route (EAEC 2001s:15-16). No archaeological resources were identified as a result of these surveys.

Staff requested that the applicant also provide a survey of *historic* resources, conducted by an architectural historian or person with an appropriate historic background. The applicant asked that staff consider the quality of the information, not necessarily the title of the person producing it. Staff agreed to accept information, however it was produced, that adequately addressed the presence and significance potential historic resources in the vicinity of the project. The applicant then conducted an historic resources survey and submitted it to the Energy Commission. However, the information provided did not meet requirements under law for either a CEQA or NEPA evaluation of historic properties.

Because staff needed a more thorough survey for its analysis, staff hired a qualified consultant to conduct another historic architectural resources field survey inventory and evaluation (Maniery 2001). The survey and inventory included structures and linear resources that had not been previously recorded and that were located within the project impact area. Photographs were taken and DPR 523A forms were completed for 27 properties. Historical research was performed for the 16 properties that were evaluated and for which a DPR 523B (Building, Structure, Object) or DPR 523 L (Linear Feature Record) form was also completed. The summary information about historical properties in this section is derived from the information on these forms.

The 27 inventoried properties are identified in Table 1 (Maniery 2001). Linear resources include the Southern Pacific Railroad Grade (Resource No. 1 in Table 1) and Byron Bethany Road (Resource No. 2). Both were originally built in 1878. The reclaimed water line route is in the Byron Bethany Road right-of-way and the Southern Pacific Railroad Grade runs directly adjacent and parallel with Byron Bethany Road.

The rail line between Tracy and Martinez was originally built as an alternate route to Oakland because the Central Pacific's line from Tracy to Oakland had to traverse Altamont Pass using a steep grade. The Tracy to Martinez route to Oakland was longer, but was fairly level. The Tracy to Martinez was acquired by the Central Pacific and then by the Southern Pacific. The Southern Pacific Railroad was acquired by the Union Pacific Railroad in the 1990s. The railroad through the project area was important to local farmers and allowed them to ship grain to market. The railroad stop in the project area was at the town of Bethany near the southern end of the reclaimed water line route.

Byron Bethany Road was originally built in 1878 as a dirt road paralleling the railroad and was used by the railroad for construction and maintenance. The road is currently a paved two lane county road. During the late nineteenth and early twentieth centuries the Southern Pacific Railroad Grade and the Byron Bethany Road were the two most important transportation routes in the area and connected the project area with the surrounding region. There is one other road in the project area that dates to the historic period. Mountain House Road (Resource No. 3) was originally built about 1874 to connect the community of House with the wider region. It was straightened and realigned in 1889. The road is now a paved two lane county road.

Several electrical transmission lines cross the project area. The oldest is the PG&E Distribution Line (Resource No. 7) which runs along Byron Bethany Road. It was built in 1909 by the Stanislaus Electric Company which generated hydroelectric power at a powerhouse on the Stanislaus River in the Sierra Nevada foothills. The transmission line in the project area was a distribution line that carried power into the project area from the company's main transmission line from the Stanislaus River powerhouse through Tracy to Oakland. The transmission line is supported by wooden poles with wooden cross members. Insulation is provided by ceramic insulators. A substation (Resource No. 22) for the transmission line, built in 1910, is located along the transmission line northwest of the Delta Mendota Intake Channel. The transmission line and substation are now owned by PG&E.

The other transmission lines in the project area are part of the Central Valley Project, a large water conveyance project built by the Bureau of Reclamation in the late 1940s and completed by 1952. The Central Valley project was designed to provide water for irrigation in the western San Joaquin Valley north of Fresno. The Central Valley Project made up to one million acres available for irrigation agriculture that were formerly dry and was described as the "most ambitious public works project ever built" (Hattersley-Drayton 2000).

In the project area the Central Valley Project consists of the Delta Mendota Canal and Intake Channel (Resource No. 27), the Tracy Pumping and Switch Station (Resource No. 11), the Hurley-Tracy Transmission Line (Resource No. 4), the Tracy-Contra Costa-Ygnacio Transmission Line (Resource No. 5), and the Tracy-Los Vaqueros Transmission Line (Resource No. 6).

Water is delivered from Shasta Dam via the Sacaramento River to the Delta and Old River. An Intake Channel brings water from the Old River to the Tracy Pumping Station

where water is lifted 197 feet to the beginning of the Delta Mendota Canal. The canal runs 116 miles to the Mendota Pool near Fresno. The massive pumps in the pumping station are powered by electricity from a hydroelectric powerhouse at Shasta Dam. The electricity is transmitted to the Tracy Switching Station for use by the Tracy Pumping Station by the Hurley-Tracy Transmission Line. Surplus power is transmitted from the switching station to customers by the Tracy-Contra Costa-Ygnacio Transmission Line and the Tracy-Los Vaqueros Transmission Line. The Intake Channel is trapezoidal in cross section and is concrete lined. It is 75 feet wide at the water line and has an average depth of 16 feet.

The Tracy Pumping and Switch Station consists of 18 structures. One of these is a large metal structure over the Intake Channel which forms part of the pumping facility. Other structures are offices, storage buildings, and sheds. The buildings are mostly one story metal clad structures, although the office has wood siding and there is one concrete building. The complex also has metal electrical switching equipment and transmission towers. The transmission lines are supported by standard design latticed steel towers set on concrete piers. The transmission lines have a capacity of 230 kv. All three of the lines were built in 1951. Ownership of the transmission lines was transferred from the Bureau of Reclamation to the Western Area Power Administration (Western) in 1977. A more recent higher capacity transmission line, the Olinda Tracy Transmission Line, was completed adjacent to the Hurley-Tracy Transmission Line by Western in 1993. This line runs from near Redding to the Tracy Switch Station and can transmit 550 kv. It has towers in a different style from the 1951 lines.

Other water conveyance facilities in the project area are parts of local agricultural irrigation systems. The Westside Irrigation District Complex (Resource No. 8) is located near the south end of the reclaimed water line route. The complex consists of a 100 foot wide intake canal leading south from the Old River to a pump station and other structures near the intersection of Wicklund Road and Byron Bethany Road. The pump station lifts water to an aqueduct which feeds two main canals that irrigate fields south of the project area. The complex was completed in 1917. The pump station is a two story concrete structure with six bays. Also included in the complex are an electrical substation, a warehouse, two houses in Craftsman style, and two sheds. The entire complex remains much as it was in 1917. The only apparent modification is a new roof on the pump station. The completion of the irrigation complex changed agriculture in the area from extensive winter rainfall dependent grain cultivation to more water intensive summer crops such as sugar beets, alfalfa, and nuts.

The Byron Bethany Irrigation District is located north of the Westside Irrigation District and the main canal of the Byron Bethany District runs through much of the project area. The canal was originally dirt lined, but some sections are now concrete lined. The canal was completed in 1919. During a system upgrade in 1968 the original pumps were replaced and many of the canals were lined with concrete.

The Mountain House School (Resource No. 10) is located one half mile south of the gas line route on Mountain House Road. The present school building was constructed in 1923 and replaced a school building that was built in 1889. The present school building is a stuccoed wood frame structure with a central entry and a classroom to the left and

an auditorium to the right. The original building was substantially remodeled during a seismic retrofit program in 1976.
The Livermore Yacht Club (Resource No. 15) is located on an inlet of the Old River about ½ mile northeast of the reclaimed water line route in the northeast corner of Alameda County. The yacht club was begun in 1937 and additional buildings were added after 1952. It consists of a community of about 46 houses, a store, public restroom, and other ancillary facilities. The store and most of the older houses have been renovated and remodeled over the years. In addition, there are houses that date to the 1960s and later.

The other resources of historic age in the project area are all ranch or farm houses with associated structures, such as barns and sheds. Of the 13 inventoried farm/ranch complexes, only the Patterson Ranch, the Costa Ranch, the Dexter Ranch, and the Kuhn Ranch date to the period of early agricultural development prior to 1930 when extensive grain farming was being replaced by irrigation agriculture.

The Patterson Ranch (Resource No. 13) was begun circa 1920 by the Mohr family and the complex consists of a main house, two barns, sheds and storage buildings. There are also four mobile homes. The main house actually consists of two older houses that have been connected. The property was originally owned by Mary Mohr whose family owned Mohr's Landing and much other acreage in the project area. Mrs. Mohr left the property to her friend, Mrs. Patterson, in the early 1940s. It was at this time that a second house was moved from elsewhere and connected to the original house. The building complex on the Costa Ranch (Resource No. 16) was begun circa 1900 by H. Lindemann. There are two houses (one in Craftsman style), a barn, a hay storage structure, and two storage sheds. Mr. Furtado purchased the property in 1943 and tore down one of two houses present on the property at that time. The surviving house is probably the Craftsman style house present on the property today. The style suggests it was built in the 1920s. The ranch is presently owned by the Costas. Manuel Costa worked for Mr. Furtado and married his daughter.

The Dexter Ranch (Resource No. 18) was begun circa 1917 by the Peterson family. There are three houses, a barn, a hay storage building, and three sheds. One of the houses is a modern ranch style house. The other two houses predate 1956 and are vernacular in style. One of the two older houses reportedly consists of the pre-1923 Mountain House School building that was moved to this location and modified with additions to make the house. The Petersons sold the ranch to Mr. McFall who added the school building house in 1923. McFall sold the ranch to the Dexters in 1944. With the exception of the two older houses, most of the other buildings are less than 50 years old.

At the Kuhn Ranch (Resource No. 20) construction of the extant buildings was begun circa 1925 by John Holck. There are a house, a barn, and two sheds. The single story house has several extensions which appear to be later additions. All original windows have been replaced with aluminum slider windows. The property was originally part of a larger parcel owned by L. Ellerbrook as early as 1874. The house was built in 1925 by John Holck who bought the property from William Saxover who had purchased it from Ellerbrook in 1917. A subsequent owner was Joseph Whalen who sold the property to the present owner, Dolores Kuhn.

Table 1 Cultural Resources Near East Altamont Energy Center Project

Resource Number.	Name/Address	Date of Construction	Not Evaluated	Appears Eligible	Appears Not Eligible
1	Southern Pacific Railroad Grade (segment)	1878			X
2	Byron Bethany Road (Segment)	1878			X
3	Mountain House Road (segment)	circa 1874			X
4	Hurley-Tracy Transmission Line (segment)	1951			X
5	Tracy-Contra Const-Ygnacio Transmission Line (segment)	circa 1946-1951			X
6	Tracy-Los Vaqueros Transmission Line (segment)	circa 1946-1951			X
7	PG&E Distribution Line (Segment)	1909	X		
8	West Side Irrigation District Complex, Wicklund Rd.	1917		X	
9	Byron Bethany Irrigation District Canal	1919, 1968			X
10	Mountain House School 3950 Mountain House Road	1923			X
11	Tracy Pumping and Switch Stations 16650 Kelso Rd.	1952			X
12	Adobe Ranch Complex 17700W. Byron Rd.	1931			X
13	Patteson Ranch 17491 & 17590 Kelso Rd.	circa 1920, 1940s	X		
14	Ranch 16941 S. Kelso Rd.	circa 1940	X		
15	Livermore Yacht Club	1937-1970s	X		
16	Costa Ranch 5840 Lindeman Rd.	circa 1944	X		
17	Wing Ranch Kelso Dd.	circa 1944			
18	Dexter Ranch 17499 Kelso Rd.	circa 1917			X
19	Holck Ranch 16606 Kelso Rd.	1948			X
20	Kuhn Ranch 4378 Mountain House Rd.	circa 1925			X
21	Schropp Farm Complex 3880 Mountain House Rd.	circa 1944, 1960s			X
22	PG&E Substation Byron Bethany Rd.	circa 1910	X		
23	Peterson Ranch 15991 Kelso Rd.	circa 1956	X		
24	Griffith Property 15616 Kelso Rd.	circa 1950	X		
25	Clark Ranch 15685 Kelso Rd.	circa 1942	X		
26	Jess Property 15547 Kelso Rd.	circa 1940s	X		
27	Delta Mendota Canal and Intake Channel (segment)	1946-1952		X	

Native American Contacts

The applicant contacted the Native American Heritage Commission (NAHC) to obtain a list of Native Americans to be contacted for the project area. The NAHC provided names of contacts for Alameda, Contra Costa, and San Joaquin Counties. On May 3, 2001, the applicant sent letters to these 12 individuals which described the project and asked about concerns. No responses were received. The NAHC searched its sacred lands file and found no listings for the project area.

Energy Commission staff has obtained a list of concerned Native American individuals and groups from the NAHC. Those names have been added to the general information list for this project and they will be sent notices regarding public workshops.

Western also contacted the NAHC and sent letters to 10 individuals and tribes. Western will be following up the letters with telephone calls to see if there is any interest or additional information on ethnographic use in the project area.

CATEGORIZATION OF IDENTIFIED CULTURAL RESOURCES

Various laws apply to the treatment of cultural resources. These laws require the Energy Commission and Western to categorize cultural resources by determining whether they meet sets of specified criteria. These categories then in turn influence the analysis of potential impacts to the cultural resources and the methods and consultation required to mitigate any such impacts.

Under federal law, only historical or prehistoric sites, objects, or features, or architectural resources that are assessed as "significant" in accordance with federal guidelines need to be considered in analyzing potential impacts. The significance of historical and prehistoric cultural resources is based on the criteria for eligibility for nomination to the NRHP as defined in Title 36 Code of Federal Regulations, section 60.4. If such resources are determined to be significant, and therefore eligible for listing in the NRHP, as well as the CRHR, they are afforded certain treatment under the National Historic Preservation Act and/or CEQA. Western is responsible for meeting the requirements of NHPA and the Energy Commission is responsible for meeting the requirements of CEQA.

The National Register criteria state that "eligible historic properties" are: districts, sites, building, structures, and objects that possess integrity of location, design, setting, materials, workmanship, feeling, and association, and that

a) are associated with events that have made a significant contribution to the broad patterns of our history; or
b) that are associated with the lives of persons significant in our past; or
c) that embody the distinctive characteristics of a type, period, or method of construction, or that represent the work of a master, or that possess high artistic values, or that represent a significant and distinguishable entity whose components may lack individual distinction; or
d) That have yielded, or may be likely to yield, information important to history or prehistory. Isolated finds by definition do not meet these criteria. California has adopted a very similar set of criteria for assessing resources of statewide importance.

Under federal law, cultural resources determined not to be significant, that is, not eligible for National Register listing, are subject to recording and documentation only, and are afforded no further treatment. However, occasionally certain resources, although they may not be assessed as "significant," may nonetheless be of local or regional importance such that mitigation may be warranted regardless of their assessed significance. Energy Commission staff and Western evaluate the survey reports and site records for any known resources located within or adjacent to the project Area of Potential Effects (APE) to determine whether they meet the eligibility criteria.

The record and literature search and the pedestrian surveys of the proposed project APE were conducted to identify the presence of any cultural resources . Where cultural resources were identified, additional evaluation was conducted to determine whether the resources are already listed on, or are potentially eligible for listing on, either the NRHP [36 CFR 800] or the CRHR. The determination of eligibility is made in compliance with the applicable provisions of the National Historic Preservation Act.

CEQA Guidelines explicitly require the lead agency (in this case, the Energy Commission) to make a determination of whether a proposed project will affect "historical resources." The guidelines provide a definition for historical resources and set forth a listing of criteria for making this determination. These criteria are the eligibility criteria for the CRHR and are essentially the same as the eligibility criteria for the NRHP. In addition, as with the NRHP, historical resources must also possess integrity of location, design, setting, materials, workmanship, feeling, and association. Resources eligible for the CRHR may have less integrity than the resources eligible for the NRHP. If the criteria are met and the resource is determined eligible for the CRHR, the Energy Commission must evaluate whether the project will cause a "substantial adverse change in the significance of the historical resource," which the regulation defines as a significant effect on the environment.

CEQA also contains a section addressing "unique" archeological resources and provides a definition of such resources (Public Resources Code, Section 21083.2). This section establishes limitations on analysis and prohibits imposition of mitigation measures for impacts to archeological resources that are not unique. However, the CEQA Guidelines state that the limitations in this section do not apply when an archeological resource has already met the definition of an historical resource (Title 14, California Code of Regulations, Section 15064.5). Since staff has determined that the sites for which it is recommending mitigation meet the definition of historical resources, the prohibition does not apply to the mitigation discussed in this staff assessment.

ANALYSIS AND IMPACTS

Since project development and construction usually entail surface and subsurface disturbance, the proposed East Altamont Energy Center Project has the potential to adversely affect both known and unknown cultural resources. Staff has analyzed the potential direct, indirect, and cumulative impacts from the proposed project. Direct impacts are those which may result from the immediate disturbance of resources, whether from vegetation removal, vehicle travel over the surface, earth-moving activities, excavation or demolition. Indirect impacts are those which may result from

increased erosion due to site clearance and preparation, or from inadvertent damage or vandalism due to improved accessibility. Cumulative impacts to cultural resources may occur if increasing amounts of land are cleared and disturbed for the development of multiple projects in the same vicinity as the proposed project.

The potential for the project to cause impacts to cultural resources is related to the likelihood that such resources are present and whether they are actually encountered during project development and construction activities. Although the existence of known cultural resources increases the potential for additional resources, the absence of known resources does not necessarily mean that unknown resources will not be encountered and that impacts will therefore not occur.

PROJECT SPECIFIC IMPACTS

Archaeological Resources

The archaeological inventories for the plant site and linear components did not record any archaeological sites within the project APE. Therefore, there are no known impacts to archaeological resources.

Because project-related site development and construction would entail subsurface disturbance, the proposed project has the potential to impact as yet unidentified subsurface cultural resources. Although no previously recorded archaeological sites will be impacted by the project, the presence of prehistoric artifacts near Mountain House Creek indicates that there is a potential for encountering buried prehistoric cultural material during construction of the reclaimed water line along Byron-Bethany Road where it crosses Mountain House Creek. There is a also a potential to encounter buried resources from the historic period during construction of the reclaimed water line in the vicinity of the town sites of Bethany, Wicklund, and historic archaeological site P-39-000345. If archaeological sites encountered during construction are evaluated as eligible for the CRHR or the NRHP, impacting these sites result in a significant impact and an adverse effect, unless mitigated.

Historical Structures and Infrastructure

The historic survey conducted by the applicant did not identify any historic resources in the vicinity of the project. They concluded, based on their own criteria, that with the exception of Mountain House School (1/2 mile from the project), no other structures appeared to be 45 years old or eligible for listing in the NRHP or CRHR.

Energy Commission and Western staff believe that the evaluation of historic structures provided by the applicant is inadequate, since it based all evaluations on potential age and façade. This evaluation did not meet the requirements for evaluating historic resources provided in either CEQA or NHPA.

As noted earlier, the Energy Commission employed a qualified consultant to assess historic resources with one mile of the project site and linears. Results differed considerably from those of the applicant. This historian evaluated the 27 properties identified as 45 years or older (Table 1) The consultant recommended two historic resources in the project area as eligible to both the NRHP and the CRHR. The historic

resources are a segment of The Delta Mendota Canal and Intake Channel and The Westside Irrigation District Complex. The Delta Mendota Canal retains integrity and is eligible under Criterion A because it contributed to the broad historic pattern of the development of the state-wide water control public works program. It is eligible under Criterion C because it is an excellent example of a revolutionary scale of canal construction. The Westside Irrigation District Complex retains integrity and is eligible under Criterion A because it is oldest intact example of the development of regional irrigation districts which altered farming practices and led to increased economic and residential development.

The other resources in the project vicinity that are potentially eligible under Criterion A, such as the Southern Pacific Railroad Grade, the Byron Bethany Road, the PG&E Distribution Line and Substation, the transmission lines associated with the Central Valley Project, the Byron Bethany Irrigation District Canal, the Mountain House School, and the four farm/ranch complexes that date to before 1930, do not retain integrity of workmanship and/or setting and feeling. The other resources are not old enough to have been associated with important events or persons in the history of the area (Criteria A and B) and are not architecturally distinctive (Criterion C).

Staff finds The Delta Mendota Canal eligible for the CRHR and Western will evaluate it for eligibility to the NRHP. Construction of the gas line along Kelso Road will cross the aqueduct portion of the canal south of the pumping station and construction of the water line from Mountain House Road to Bruns Road will cross the canal before it reaches the pumping station. Construction of the water and gas line could impact the canal, depending upon the-construction method.

The reclaimed water pipeline route runs along Wicklund Road parallel with the intake canal of the Westside Irrigation District. It appears that installation of the pipeline by trenching in Wicklund Road will not impact the canal because it will not cross it.

CUCUMULATIVE IMPACTS

Cumulative impacts to cultural resources in the project vicinity may occur if subsurface archaeological deposits (both prehistoric and historic) and the setting of historic structures are affected by other projects in the same vicinity as the proposed project. Residential development is proceeding north from Tracy and several projects including, the Tesla and Tracy Power Plants, are planned.

However, project proponents for this and future projects in the area can mitigate impacts to as yet undiscovered subsurface archaeological sites to less than significant. Impacts can be mitigated by requiring construction monitoring, evaluation of resources discovered during monitoring, and avoidance or data recovery for resources evaluated as significant (eligible for the CRHR or NRHP).

IMPACTS OF FACILITY CLOSURE

The anticipated lifetime of the East Altamont Energy Center Project is expected to be approximately 30 years. It is anticipated that upgrades or modifications made prior to the facility's closure might extend the life of the plant. Closure would be caused by

either (1) a natural or manmade disaster or economic difficulty, or (2) planned orderly closure that will occur when the plant becomes economically non-competitive.

PLANNED CLOSURE

At the time of planned closure, all then-applicable LORS will be identified and the Energy Commission-required closure plan will address compliance with these LORS. Generally, if no additional ground disturbance occurs during closure activities and all conditions of certification have been met, no impacts to cultural resources would be expected. However, actual potential impacts are likely to depend upon the final location of project structures in relation to existing resources, and upon the procedures used for the removal of project structures. Since the spatial relationship between the closure and removal of project structures and sensitive resources cannot be determined at this time, no conclusion can be drawn at this time with respect to the impact of facility closure on cultural resources. The closure plan, when created, will address impacts to cultural resources.

TEMPORARY CLOSURE

A temporary closure should have no impacts on cultural resources as long as no additional lands are needed for the closure. A contingency plan for temporary cessation of operation would be implemented that would ensure compliance with all applicable LORS.

UNEXPECTED PERMANENT CLOSURE

If a site were abandoned, impact to cultural resources would be unlikely because there would be no immediate soil disturbances. Over time, depending on the need to disturb the ground to accomplish project closure and facility removal, some disturbance of known and/or previously unknown cultural resources might result.

COMPLIANCE WITH APPLICABLE LORS

Connecting the power plant to existing transmission lines makes it necessary to obtain approval from the Western Area Power Administration (Western). Obtaining this approval triggers the compliance requirements of Section 106 of the National Historic Preservation Act (NHPA) and its implementing regulations, set forth in 36 CFR 800 and the National Environmental Policy Act. Western will consult with the State Historic Preservation Officer to fulfill their responsibilities under the NHPA.

The three counties in the project area have policies and goals for the protection of cultural resources, but have no specific procedures for implementation of CEQA that differ from procedures used by the Energy Commission. Implementation of the mitigation measures recommended in the conditions of certification will ensure compliance with LORS.

MITIGATION

For cultural resources, the preferred method of mitigation is for project construction to avoid areas where cultural resources are known to exist, wherever possible. Often,

however, avoidance cannot be achieved, and other measures such as surface collection, subsurface testing, and data recovery must be implemented for archaeological resources and documentation must be implemented for historical structures. Mitigation measures are developed to reduce the potential for adverse project impacts on cultural resources to a less than significant level.

APPLICANT'S PROPOSED MITIGATION

Archaeological Resources

The applicant recommends full time construction monitoring by a qualified archaeologist in the vicinity of the town site of Wicklund and elsewhere on full time or part time basis at the discretion of the archaeologist. If archaeological material is observed by the monitoring archaeologist, ground disturbing activity would be halted in the vicinity of the find so that its significance (CRHR eligibility) can be evaluated. The evaluation plan would be reviewed by the Energy Commission. If evaluated as significant, mitigation measures (avoidance or data recovery) would be developed in consultation with the Energy Commission.

The applicant recommends a worker education program to ensure that buried archaeological resources are recognized by construction crews. Such a program would include information about the kinds of archaeological material that could be encountered and the procedures to be followed if such material is discovered.

Historic Architectural Resources

No mitigation measures for historic architectural resources were recommended by the applicant.

STAFF'S PROPOSED MITIGATION MEASURES

Commission staff concurs with the mitigation measures proposed by the Applicant for archaeological resources, but recommends extending the area where full time monitoring will take place. Full time monitoring would take place during construction of the reclaimed water line for 1000 feet on each side of its intersection with Mountain House Creek. In addition, full time monitoring should take place during construction of the reclaimed water line from 1,000 feet prior to its intersection with Henderson and Bethany Roads to the end of the reclaimed water line near the town site of Wicklund.

Staff recommends installation of the gas line and the water line under the Delta Mendota Canal by boring. Use of this construction method will not impact the Delta Mendota Canal.

The proposed mitigation measures would apply to any potential for impacts to sensitive cultural resources in all areas affected by the project. Mitigation measures are derived from good professional practice and they are based on the U.S. Secretary of the Interior's Guidelines. The mitigation measures set forth in the conditions have been applied to previous projects before the Commission and they have proven successful in protecting sensitive cultural resources from construction-related impacts while allowing the timely completion of many projects throughout California.

WESTERN'S PROPOSED MITIGATION MEASURES

Western does not believe that monitoring is necessary to prevent significant impacts to cultural resources based on the fact that no archaeological sites were recorded during the intensive pedestrian inventory.

The Delta Mendota Canal and the Westside Irrigation District have been recommended as eligible for inclusion in the NRHP, under the NHPA, Western will be consulting with the California SHPO on appropriate mitigation measures.

CONCLUSIONS AND RECOMMENDATION

The results of the records search indicate that buried archaeological resources from the prehistoric and historic periods could be encountered during construction of the reclaimed water line. If the following conditions of certification are properly implemented, the project will comply with applicable laws, ordinances, regulations, and standards for archaeological resources any impacts will be reduced below a significant level. **Cul-1**, **Cul-5**, **Cul-7**, **Cul-8** and **Cul-9** are written to address the mitigation recommendations of both the Energy Commission and Western under state and federal law. **Cul-2**, **Cul-3**, **Cul-4** and **Cul-6** are written to address the mitigation recommendations of the Energy Commission under state law.

Staff recommends that the Commission adopt the following proposed conditions of certification, which incorporate the mitigation measures discussed above.

PROPOSED CONDITIONS OF CERTIFICATION

CUL-1 Prior to the start of ground disturbance, the project owner shall provide the California Energy Commission Compliance Project Manager (CPM) and Western Area Power Administration (Western) with the name and resume of its Cultural Resources Specialist (CRS), and one alternate CRS, if an alternate is proposed, who will be responsible for implementation of all cultural resources conditions of certification.

(1) The resume for the CRS and alternate, if an alternate is proposed, shall include information that demonstrates that the CRS meets the minimum qualifications specified in the U.S. Secretary of Interior Guidelines, as published in the Code of Federal Regulations, Title Section 61 (2000).

The technical specialty of the CRS shall be appropriate to the needs of this project and shall include a background in anthropology, archaeology, history, architectural history or a related field

The background of the CRS shall include at least three years of archaeological or historic, as appropriate, resource mitigation and field experience in California; and at least one year's experience in each of the following areas:

1. principal investigator for archeological field surveys;

2. principal investigator for site mapping and recording;
3. principal investigator for site testing and data recovery, including sampling for dating and botanical studies and small artifact recovery;
4. principal investigator for laboratory studies of collected materials; and
5. Preparing reports for a curation repository, the State Historic Preservation Officer, and the appropriate regional archaeological information center(s).

(1)The resume shall include the names and phone numbers of contacts familiar with the CRS's work on referenced projects.

(2)The resume shall also demonstrate to the satisfaction of the CPM, the appropriate education and experience to accomplish the cultural resource tasks that must be addressed during project ground disturbance, construction and operation.

(3) The CRS may obtain qualified cultural resource monitors, as necessary, to monitor on the project. Cultural resource monitors shall meet the following qualifications.

A BS or BA degree in anthropology, archaeology, historic archaeology or a related field and one year experience monitoring in California; or

An AS or AA in anthropology, archaeology, historic archaeology or a related field and four years experience monitoring in California; or

Enrollment in upper division classes pursuing a degree in the fields of anthropology, archaeology, historic archaeology or a related field and two years of monitoring experience in California.

(4) The project owner shall ensure that the CRS completes any monitoring, mitigation and curation activities necessary to this project and fulfills all the requirements of these conditions of certification. The project owner shall also ensure that the CRS obtains additional technical specialists, or additional monitors, if needed, for this project. The project owner shall also ensure that the CRS evaluates any cultural resources that are newly discovered or that may be affected in an unanticipated manner for eligibility to the California Register of Historic Resources (CRHR).

Verification (1) At least 90 days prior to the start of ground disturbance, the project owner shall submit the name and statement of qualifications of its CRS and alternate CRS, if an alternate is proposed, to the CPM for review and approval. (2) If the CPM determines the proposed CRS to be unacceptable, the project owner shall submit another individual's name and resume for consideration. If the CPM determines the proposed alternate to be unacceptable, the project owner may submit another individual's name and resume for consideration.

At least 10 days prior to the termination or release of the CRS, the project owner shall submit the resume of the proposed new CRS to the CPM for

review and approval.

(3) At least 20 days prior to ground disturbance, the CRS shall provide a letter naming anticipated monitors for the project and stating that the identified monitors meet the minimum qualifications for cultural resource monitoring required by this condition. If additional monitors are obtained during the project, the CRS shall provide additional letters to the CPM, identifying the monitor and attesting to the monitor's qualifications. The letter shall be provided one week prior to the monitor beginning on-site duties.

(4) At least 10 days, prior to the start of 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 of certification.

CUL-2 (1) Prior to the start of ground disturbance, the project owner shall provide the CRS and the CPM with maps and drawings showing the footprint of the power plant and all linear facilities. Maps shall include the appropriate USGS quadrangles and a map at an appropriate scale (e.g., 1:2000 or 1" = 200') for plotting individual artifacts. If the CRS request enlargements or strip maps for linear facility routes, the project owner shall provide them with copies to the CPM. If the footprint of the power plant or linear facilities changes, the project owner shall provide maps and drawings reflecting these changes, to the CRS and the CPM. Maps shall identify all areas of the project where ground disturbance is anticipated.

(2) If construction of this project will proceed in phases, maps and drawings may be submitted in phases. A letter identifying the proposed schedule of each project phase shall be provided to the CPM. (3) Prior to implementation of additional phases of the project, current maps and drawings shall be submitted to the CPM.

(4) At a minimum, the CRS shall consult weekly with the project superintendent or construction field manager to confirm area(s) to be worked during the next week, until ground disturbance is completed. A current schedule of anticipated project activity shall be provide to the CRS on a weekly basis during ground disturbance and provided to the CPM in each Monthly Compliance Report (MCR).

Verification: (1) At least 75 days prior to the start of ground disturbance, the project owner shall provide the designated cultural resources specialist and the CPM with the maps and drawings. (2) If this is to be a phased project, a letter identifying the proposed schedule of construction phases of the project shall also be submitted. (3) At least 30 days prior to the start of ground disturbance on each phase of the project, following initial ground disturbance, copies of maps and drawings reflecting additional phases of the project, shall be provided to the CPM for review and approval. (4) If there are changes to the scheduling of the construction phases of the project, a letter shall be submitted to the CPM within 5 days of identifying the changes. A copy of the current

schedule of anticipated project activity and a copy of current maps shall be submitted in each MCR.

CUL- 3 Prior to the start of ground disturbance; the designated cultural resources specialist shall prepare, and the project owner shall submit to the CPM for review and approval, a Cultural Resources Monitoring and Mitigation Plan (CRMMP), identifying general and specific measures to minimize potential impacts to sensitive cultural resources. Approval of the CRMMP, by the CPM, shall occur prior to any ground disturbance.

Protocol: The CRMMP shall include, but not be limited to, the following elements and measures.

a. A proposed general research design that includes a discussion of questions that may be answered by the mapping, data and artifact recovery conducted during monitoring and mitigation activities, and by the post-construction analysis of recovered data and materials.
b. Specification of the implementation sequence and the estimated time frames needed to accomplish all project-related tasks during ground disturbance, construction, and post-construction analysis phases of the project.
c. Identification of the person(s) expected to perform each of the tasks; a description of each team member's qualifications and their responsibilities; and the reporting relationships between project construction management and the mitigation and monitoring team.
d. A discussion of the inclusion of Native American observers or monitors, the procedures to be used to select them, and their role and responsibilities.
e. A discussion of all avoidance measures such as flagging or fencing, to prohibit or otherwise restrict access to sensitive resource areas that are to be avoided during construction and/or operation, and identification of areas where these measures are to be implemented. The discussion shall address how these measures will be implemented prior to the start of construction and how long they will be needed to protect the resources from project-related effects.
f. A discussion of the location(s) where monitoring of ground disturbing activities is deemed necessary. Monitoring shall be conducted full time, during ground disturbance on the reclaimed water line from 1000 feet prior to its intersection with Henderson and Bethany Roads to its end. Spoils generated by ground disturbance shall be examined every other day to determine whether there is evidence of cultural resources.
g. A discussion of the requirement that all cultural resources encountered will be recorded on a DPR form 523 and mapped (may include photos). In addition all archaeological materials collected as a result of the archaeological investigations shall be curated in accordance with The State Historical Resources Commission's "Guidelines for the Curation of Archaeological Collections," into a retrievable storage collection in a public repository or museum. The public repository or museum must meet the standards and requirements for the curation of cultural

resources set forth at Title 36 of the Code of Federal Regulations, section 79.

Discussion of any requirements, specifications, or funding needed for curation of the materials to be delivered for curation and how requirements, specifications and funding will be met. Also the name and phone number of the contact person at the institution shall be included. In addition, include information indicating that the project owner will pay all curation fees and that any agreements concerning curation will be retained and available for audit for the life of the project.

h. A discussion of the availability and the designated specialist's access to equipment and supplies necessary for site mapping, photographing, and recovering any cultural resource materials encountered during construction.
i. A discussion of the proposed Cultural Resource Report (CRR) which shall be prepared according to Archaeological Resource Management Report (ARMR) Guidelines. The CRR shall include **all** cultural resource information obtained as a result of this project. All survey reports, monitoring records and additional research reports not previously submitted to the California Historic Resource Information System (CHRIS) shall be included as an appendix to the CRR. This report shall be submitted to the CPM after the conclusion of ground disturbance (including landscaping). This report shall be considered final upon approval by the CPM.

Verification At least 30 days prior to the start of ground disturbance, the project owner shall provide the Cultural Resources Monitoring and Mitigation Plan, prepared by the CRS, to the CPM for review and written approval.

CUL-4 Worker Environmental Awareness Training for all new employees shall be conducted prior to and during periods of ground disturbance. New employees shall receive training prior to starting work at the project site or linears. The training may be presented in the form of a video. The training shall include a discussion of applicable laws and penalties under the law. Training shall also include samples or visuals of artifacts that might be found in the project vicinity and the information that the CRS, alternate CRS or monitor has the authority to halt construction in the event of a discovery or unanticipated impact to a cultural resource. The training shall also instruct employees to halt or redirect work in the vicinity of a find and to contact their supervisor and the CRS or monitor. An informational brochure shall be provided that identifies reporting procedures in the event of a discovery. Workers shall sign an acknowledgement form that they have received training and a sticker shall be placed on hard hats indicating that environmental training has been completed.

Verification At least 30 days prior to ground disturbance, the project owner shall provide a letter to the CPM stating that employees will not begin work until they have completed environmental training and that a sticker on hard hats will identify workers who have received training. Copies of acknowledgement forms signed by trainees shall be provided in the MCR.

CUL-5 The CRS, alternate CRS and the Cultural Resources Monitor(s) shall have the authority to halt or redirect construction if previously unknown cultural resource sites or materials are encountered or if known resources may be impacted in a previously unanticipated manner.

If such resources are found, the halting or redirection of construction shall remain in effect until all of the following have occurred:

a. the CRS has notified the CPM and the project owner of the find and the work stoppage;

b. the CRS, the project owner, the CPM and Western have conferred and determined what, if any, data recovery or other mitigation is needed; and

c. any necessary data recovery and mitigation has been completed.

If data recovery or other mitigation measures are required, the CRS and/or the alternate CRS and cultural resource monitor(s), including Native American monitor(s), shall monitor these data recovery and mitigation measures, as needed.

For any cultural resource encountered, the project owner shall notify the CPM within 24 hours after the find.

All required data recovery and mitigation shall be completed expeditiously unless all parties agree to additional time.

Verification At least 30 days prior to the start of ground disturbance, the project owner shall provide the CPM with a letter confirming that the CRS, alternate CRS and cultural resources monitor(s) have the authority to halt construction activities in the vicinity of a cultural resource find and stating that the CRS will notify the CPM and project owner within 24 hours after a find.

CUL-6 (1) Cultural resource monitoring shall be conducted full time from 1000 feet on each side of the reclaimed water line's intersection with Mountain House Road. Full time monitoring shall also be conducted from 1000 feet prior to the intersection with Henderson and Bethany Roads to the end of the reclaimed water line to ensure there are no impacts to undiscovered cultural resources. (2) Cultural resources monitoring shall be conducted during initial ground breaking at the plant site and all linear components. The potential for encountering cultural resources shall be assessed by the CRS based on the initial ground breaking observations. If the initial assessment indicates a potential for encountering cultural resources, then full time monitoring shall continue until the CRS concludes and justifies to the CPM that full time monitoring is no longer necessary. If the CRS determines that encountering cultural resources are unlikely, all spoils from ground disturbance shall be examined every other day as ground disturbing project activities continue. If the CRS determines that full-time monitoring or spoil examination is not necessary in certain locations, a letter providing a detailed justification for the decision to reduce the level of monitoring

shall be provided to the CPM for review and approval prior to any reduction in monitoring.

(2) Monitors shall keep a daily log of any monitoring or cultural resource activities and the CRS shall prepare a weekly summary report on the progress or status of cultural resources-related activities providing an update that may include information that no monitoring activities have occurred. The CRS may informally discuss cultural resource monitoring and mitigation activities with Energy Commission technical staff.

(3) The CRS shall notify the project owner and the CPM, by telephone, of any incidents of non-compliance with any cultural resources conditions of certification within 24 hours. of becoming aware of the situation. The CRS shall also recommend corrective action to resolve the problem or achieve compliance with the conditions of certification. A report detailing resolution of the issue shall be provided to the CPM in the MCR no earlier than two weeks following the incident.

(4) A Native American monitor shall be obtained to monitor ground disturbance in areas where Native American artifacts may be discovered. Informational lists of concerned Native Americans and Guidelines for monitoring shall be obtained from the Native American Heritage Commission. Preference in selecting a monitor shall be given to Native Americans with traditional ties to the area that will be monitored.

Verification (1) During the ground disturbance phases of the project, if the CRS wishes to reduce the level of monitoring occurring at the project, a letter identifying the area(s) where the CRS recommends the reduction and justifying the reductions in monitoring shall be submitted to the CPM for review and approval.

(2) During the ground disturbance phases of the project, the project owner shall include in the MCR to the CPM copies of the weekly summary reports prepared by the CRS regarding project-related cultural resources monitoring activities. Copies of daily logs shall be retained and made available for audit by the CPM as needed.

(3) Within 24 hours of recognition of a non-compliance issue, the CRS shall notify the CPM by telephone of the problem. Daily logs shall include forms detailing any instances of non-compliance with conditions of certification. In the event of a non-compliance issue, a report written no sooner than two weeks after resolution of the issue shall be provided in the next MCR.

(4) One week prior to ground disturbance in areas where there is a potential to discover Native American artifacts, the project owner shall send notification to the CPM identifying the person(s) retained to conduct Native American monitoring. If efforts to obtain the services of a qualified Native American monitor are unsuccessful, the project owner shall immediately inform the CPM who will initiate a resolution process.

CUL-7 Following the discovery of significant cultural resources, the project owner shall ensure that the CRS prepares a research design and a scope of work for any necessary data recovery or additional mitigation. The project owner shall submit

the proposed research design and scope of work to Western's archeologist and the CPM for review and approval.

Protocol: The proposed research design and scope of work shall include (but not be limited to):

a. a discussion of the methods to be used to recover additional information and any needed analysis to be conducted on recovered materials;

b. a discussion of the research questions that the materials may address or answer by the data recovered from the project;

c. discussion of possible results and findings; and

d. an estimate of the time, personnel, and costs needed to complete the recovery and analysis of materials and to prepare report.

Verification: The project owner shall ensure that the CRS prepares the research design and scope of work within the shortest time possible following the determination that significant materials have been discovered. After completion of the research design and scope of work, the project owner shall submit it to Western and the CPM for review and approval. Western shall submit the research design and scope of work to the State Historic Preservation Officer as part of consultation under Section 106.

CUL-8 The project owner shall ensure that the cultural resources specialist prepares a report on any discovery of cultural resources. The project owner shall submit the report to Western and the CPM for review and approval.

Protocol: The Cultural Resources Report (CRR)shall include (but not be limited to) the following:

1. A brief description of pre-project literature search and surveys;
2. a description of the discovery;
3. a description of the process used to arrive at a determination of significance;
4. a discussion of the research questions that the recovered data could address or answer;
5. a description of the methods employed in the field and laboratory to complete data recovery efforts;
6. a description (including drawings and/or photos) of recovered cultural materials;
7. an inventory list of recovered cultural resource materials;
8. results and findings of any special analyses conducted on recovered cultural resource materials, including an interpretation of the site in regards to any research design prepared prior to the data recovery;
9. conclusions and recommendations;

10. maps (7.5 minute USGS topographic map) showing the area involved in the data recovery;
11. completed state site forms, including photos, maps, and drawings; and
12. the name and location of the public repository receiving the recovered cultural resources for curation.

If no cultural resources are identified as a result of the project, the proposed Cultural Resource Report (CRR) shall be prepared according to Archaeological Resource Management Report (ARMR) Guidelines. The CRR shall include **all** cultural resource information obtained as a result of this project. All survey reports, monitoring records and additional research reports not previously submitted to the California Historic Resource Information System (CHRIS) shall be included as an appendix to the CRR. This report shall be submitted to the CPM after the conclusion of ground disturbance (including landscaping). This report shall be considered final upon approval by the CPM and Western.

Verification: The project owner shall ensure that the CRS completes the CRR within 90 days following completion of the analysis of the recovered cultural materials. Within 7 days after completion of the report, the project owner shall submit the Cultural Resources Report to Western and the CPM for review and written approval. Western will submit the report, when approved, to the State Historic Preservation Officer in order to complete consultation under Section 106.

If no cultural resources are identified as a result of the project, the CRR shall be submitted to the CPM and Western within 90 days after the conclusion of ground disturbance, including landscaping for review and approval.

CUL-9 The cultural resources specialist shall provide a copy of a curation agreement from a public repository that meets the requirements set out in 36 CFR 79 for the curation of cultural resources in the event that cultural materials are discovered during construction activities (Condition Cul-7). In addition, the specialist shall ensure that all cultural resource materials, maps, and data collected during data recovery and mitigation for the project are delivered to the repository following the approval of the report on data recovery. The project owner shall pay any fees for curation required by the repository.

Verification: The project owner shall provide Western and the CPM with a copy of the curation agreement at least ten (10) days prior to the initiation of construction activities. If there are procedural restrictions on the issuance of such an agreement (e.g., if the repository will not issue an agreement until they know for sure that there will be material curated in their facility), the specialist shall provide a copy of an agreement no more than thirty (30) days following the discovery of cultural materials. The specialist shall provide Western and the CPM with a copy of an inventory of all materials curated at the facility and documentation that they have been accepted for curation.

For the life of the project the project, owner shall maintain in its of compliance files, copies of signed agreements with the public repository to which the project owner has delivered cultural resource materials for curation.

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HAZARDOUS MATERIALS MANAGEMENT

Alvin J. Greenberg, Ph.D. and Rick Tyler

INTRODUCTION

The purpose of this analysis is to determine if the proposed East Altamont Energy Center (EAEC) has the potential to cause a significant impact on the public as a result of the use, handling or storage of hazardous materials at the proposed facility. 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 impacts to the extent feasible.

This analysis does not address potential exposure of workers to hazardous materials used at the proposed facility. Employers must inform employees of hazards associated with their work and employees accept a higher level of risk than the general public as a condition of employment. Workers are thus not afforded the same level of protection normally provided to the public. Further, workers can be provided with special protective equipment and training to reduce the potential for health impacts associated with the handling of hazardous materials. Staff's **Worker Safety and Fire Protection** analysis describes the requirements applicable to the protection of workers from such risks.

The applicant has proposed to store four hazardous materials at the EAEC in quantities exceeding the reportable amounts defined in the California Health and Safety Code, section 25532 (j): anhydrous ammonia, sodium hydroxide, sulfuric acid, and hydrogen gas (see Table 8.12-3 of the Application for Certification [AFC] and revised in Supplement B, dated October 9, 2001, Table HM-1). Of these, anhydrous ammonia presents the greatest potential for off-site consequences. The use of anhydrous ammonia significantly increases the risk that would otherwise be associated with use of the safer aqueous form of ammonia. The anhydrous form with its high internal energy is stored as a liquefied gas at elevated pressure. The high internal energy associated with the anhydrous form of ammonia can act as a driving force in an accidental release, which can rapidly introduce large quantities of the material to the ambient air, where it can be transported in the atmosphere and result in high down-wind concentrations. Spills associated with the aqueous form are much easier to contain and the slow mass transfer from the surface of the spilled material limits emissions.

Other hazardous materials stored in smaller quantities, such as mineral and lubricating oils, corrosion inhibitors and water conditioners, will be present at the proposed facility. Hazardous materials used during the construction phase include gasoline, diesel fuel, oil, welding gases, lubricants, solvents and paint. No acutely toxic hazardous materials will be used onsite during construction. None of these materials pose significant potential for off-site impacts because of their quantities on-site, their relative toxicity, and/or their environmental mobility. Although no natural gas is stored, the project will involve the construction and operation of a natural gas pipeline and handling of large amounts of natural gas. Natural gas poses some risk of both fire and explosion. This pipeline will be 1.4 to 1.5 miles in length including on and off-site segments.

The EAEC will also require the transportation of anhydrous ammonia to the facility. Analysis of the potential for impact associated with such deliveries is addressed below.

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.

FEDERAL

The Superfund Amendments and Reauthorization Act of 1986 (Pub. L. 99-499, §301,100 Stat. 1614 [1986]), also known as SARA Title III, contains the Emergency Planning and Community Right To Know Act (EPCRA) as codified in 42 U.S.C. §11001 et seq. This Act requires that certain information about any release to the air, soil, or water of an extremely hazardous material must be reported to state and local agencies.

The Clean Air Act (CAA) of 1990 (42 U.S.C. §7401 et seq. as amended) established a nationwide emergency planning and response program and imposed reporting requirements for businesses which store, handle, or produce significant quantities of extremely hazardous materials. The CAA section on Risk Management Plans - codified in 42 U.S.C. §112(r) - requires states to implement a comprehensive system to inform local agencies and the public when a significant quantity of such materials is stored or handled at a facility. The requirements of the CAA are reflected in the California Health and Safety Code, section 25531 et seq.

Currently, due to the high volume of petroleum-containing hazardous materials already in place on this site, the applicant is required to have a Spill Prevention Control and Countermeasure Plan (SPCC) in place (Hazardous Waste Contingency Plan Title 40 C.F.R., Section 112.7).

STATE

The California Accidental Release Prevention Program (Cal-ARP) - Health and Safety Code, section 25531 - directs facility owners storing or handling acutely hazardous materials in reportable quantities, to develop a Risk Management Plan (RMP) and submit it to appropriate local authorities, the United States Environmental Protection Agency (EPA), and the designated local Administering Agency for review and approval. The plan must include an evaluation of the potential impacts associated with an accidental release, the likelihood of an accidental release occurring, the magnitude of potential human exposure, any preexisting evaluations or studies of the material, the likelihood of the substance being handled in the manner indicated, and the accident history of the material. This new, recently developed program supersedes the California Risk Management and Prevention Plan (RMPP).

Section 25503.5 of the California Health and Safety Code requires facilities which store or use hazardous materials to prepare and file a Business Plan with the local Certified Unified Program Authority (CUPA), in this case the San Luis Obispo County Health Department, Division of Environmental Health. This Business Plan is required to contain information on the business activity, the owner, a hazardous materials inventory, facility

maps, an Emergency Response Contingency Plan, an Employee Training Plan, and other recordkeeping forms.

Title 8, California Code of Regulations, section 5189, requires facility owners to develop and implement effective safety management plans to 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 RMP process.

Title 8, California Code of Regulations, section 458 and sections 500 – 515, set forth requirements for design, construction and operation of vessels and equipment used to store and transfer anhydrous ammonia. These sections generally codify the requirements of several industry codes, including the ASME Pressure Vessel Code, ANSI K61.1 and the National Boiler and Pressure Vessel Inspection Code. While these codes apply to anhydrous ammonia, they may also be used to design storage facilities for aqueous ammonia.

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."

Gas Pipeline

The safety requirements for pipeline construction vary according to the population density and land use, which characterize the surrounding land. The pipeline classes are defined as follows (Title 49, Code of Federal Regulations, Part 192):

- Class 1: Pipelines in locations with ten or fewer buildings intended for human occupancy.
- Class 2: Pipelines in locations with more than ten but fewer than 46 buildings intended for human occupancy. This class also includes drainage ditches of public roads and railroad crossings.
- Class 3: Pipelines in locations with more than 46 buildings intended for human occupancy, 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 natural gas pipeline will be designed for Class 3 service and will meet California Public Utilities Commission General Order 112-D and 58-A standards as well as various PG&E standards. The natural gas pipeline must be constructed and operated in accordance with the Federal Department of Transportation (DOT) regulations, Title 49, Code of Federal Regulations, sections 190, 191, and 192:

- Title 49, Code of Federal Regulations, section 190 outlines the pipeline safety program procedures;

- Title 49, Code of Federal Regulations, section 191, Transportation of Natural and Other Gas by Pipeline; Annual Reports, Incident Reports, and Safety-Related Condition Reports, requires operators of pipeline systems to notify the U.S. Department of Transportation of any reportable incident by telephone and then submit a written report within 30 days;
- Title 49, Code of Federal Regulations, section 192, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, specifies minimum safety requirements for pipelines and includes material selection, design requirements, and corrosion protection. The safety requirements for pipeline construction vary according to the population density and land use, which characterize the surrounding land. This section contains regulations governing pipeline construction, which must be followed for Class 2 and Class 3 pipelines.

LOCAL AND REGIONAL

The Uniform Fire Code (UFC) contains provisions regarding the storage and handling of hazardous materials in Articles 79 and 80. The latest revision to Article 80 was adapted in 1997 (Uniform Fire Code, 1997) and includes minimum setback requirements for outdoor storage of ammonia.

The California Building Code contains requirements regarding the storage and handling of hazardous materials. The Chief Building Official must inspect and verify compliance with these requirements prior to issuance of an occupancy permit. A further discussion of these requirements is provided in the **Seismic Issues** portion of this document.

If not for Energy Commission jurisdiction, the Alameda County Environmental Management Department would be the issuing agency for the Consolidated Hazardous Materials Permit. The permit review and mitigation authority covers hazardous materials, hazardous waste, compressed gases and tiered treatment, the Hazardous Materials Business Plan, and the Risk Management Plan for anhydrous ammonia. In regards to seismic safety issues, the site is located in Seismic Risk Zone *3*. Construction and design of buildings and vessels storing hazardous materials must conform to the 1997 Uniform Building Code, the 1998 California Building Code, and the Alameda County Building Code.

SETTING

The proposed project is to be located in an unincorporated area of Alameda County approximately one mile west of the San Joaquin County line, and one mile south and east of the Contra Costa County line. The site is approximately 8 miles northwest of the city of Tracy, 12 miles east of Livermore, 5 miles south of Byron, and less than one mile from the San Joaquin County border and the Mountain House Community Service District, a new town just starting Phase 1 of construction. Large infrastructure projects, principally power generation and transmission facilities dominate the surrounding area within one mile of the project. The land uses surrounding the proposed facility consist of mixed agriculture, and low-density rural residences. Hazardous materials use and transportation are commonly associated with the industrial/agricultural activities in the area. Thus, hazardous materials are transported, stored, and used in the project vicinity.

Several factors associated with the area in which a project is to be located affect its potential to cause public health impacts from an accidental release of a hazardous material. 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 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 level of public exposure to such materials and the associated health risks. When wind speeds are low and stable, dispersion is severely reduced and can lead to increased localized public exposure.

Recorded wind speeds and ambient air temperatures are described in the Air Quality section of the AFC (EAEC 2001a, AFC chapter 8.1). Staff agrees with the applicant that use of atmospheric stability class F (stagnated air, very little mixing) and one meter per second wind speed is appropriate for use in its modeling of an accidental release. Staff believes these represent a reasonably conservative scenario and thus reflects worst case atmospheric conditions.

TERRAIN CHARACTERISTICS

The location of elevated terrain (terrain above the power plant stack height) is often an important factor to be considered in assessing potential exposure. An emission plume resulting from an accidental release may impact high elevations before impacting lower elevations. With the local terrain elevated several hundred feet immediately to the west it is expected that this project will be affected by elevated terrain. No receptors are located at elevated terrain to the west. These hills contribute to the persistent winds in the project vicinity and would thus contribute to the rapid migration of ammonia from the property in the event of a storage tank rupture. Off-site concentrations of ammonia beyond the facility fenceline, however, may impact nearby receptors and potentially pose a hazard to the public.

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 large bearing on health risk. Figure 8.6-1 (AFC) shows that the location of the closest sensitive receptor in the project vicinity. The AFC states nearest sensitive receptor is a public elementary school (Mountain House School) located approximately 0.9 mile south of the project.

IMPACTS AND ANALYSIS

Staff thoroughly reviewed and assessed the potential for the transportation, handling, and use of hazardous materials to impact the surrounding community. All chemicals, including natural gas, were evaluated.

METHODOLOGY

In order to assess the potential for released hazardous materials to travel off-site, and impact on the public, staff analyzed several aspects of the proposed use of these materials at the facility. Staff recognizes that hazardous chemicals are frequently used at power plants. Therefore, staff conducted its analysis by examining the need for hazardous materials, the choice of chemical to be used and its amount, the manner in which the applicant will use the chemical, the manner it will be transported to the facility and transferred to facility storage tanks, and the way the applicant chooses to store the material on-site. Staff reviewed the applicant's proposed engineering controls and administrative controls concerning hazardous materials usage. Engineering controls are those physical or mechanical systems (such as storage tanks or automatic shut-off valves) which can prevent a spill of hazardous material from occurring or which can limit the spill to a small amount or confine it to a small area. Administrative controls are those rules and procedures that workers at the facility must follow that will help to prevent accidents or 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 people.

Staff conducted a thorough review and evaluation of the applicant's proposed use of hazardous materials as described by the applicant in the AFC (Sections 2.2.10 and 8.12) and in data responses. 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 8.12-2 and 8.12-3 of the AFC and determined the need and appropriateness of their use. If less toxic materials were available, staff suggested their use instead.
- 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 the 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 size 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 measures also included 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 potential impacts to the public of a worst-case spill of hazardous materials with the mitigation measures proposed by the Applicant. If the

mitigation methods proposed by the applicant are found to be sufficient, no further mitigation will be recommended. If the mitigation proposed by the Applicant is found to be insufficient to reduce the potential for adverse impacts to an insignificant level, staff will propose additional prevention and response controls to reduce potential impacts to an insignificant level. It is only at this point that staff can recommend that the facility permitted to use hazardous materials.

PROJECT IMPACTS

Small Quantity Hazardous Materials

In conducting the analysis, staff determined in Steps 1 and 2 that some materials, although present at the proposed facility, pose a minimal potential for off-site impacts as they will either be stored in a solid form, in smaller quantities, or have very low toxicity. These hazardous materials were thus removed from further assessment. For example, one such group of chemicals is the scale inhibitors chosen for use at the site. Scale inhibitors are used to control and reduce the potential for scale and corrosion to form within the pipeline system. The scale control agents listed in Table 8.12.2 of the AFC include phosphonate for the reverse osmosis unit and polyacrolate in the cooling tower. These chemicals are safer to use than others often used at other facilities for this purpose, such as hydrazine. Staff has determined that the potential for impacts on the public are insignificant if the applicant uses those or similar scale inhibitors and corrosion controllers mentioned above. See Table 8.12.2 and HM-2 of Supplement B for a list of chemicals that will be used at the power plant

During the construction phase of the project, the only hazardous materials proposed for use include paint, paint thinner, cleaners, solvents, sealants, gasoline, diesel fuel, motor oil, hydraulic fluid, welding flux and gases, lubricants and emergency refueling containers. Any impact resulting from spills or other releases of these materials will be limited to the site due to the small quantities involved. Fuels such as fuel oil #6, mineral oil, lube oil, and diesel fuel are all of very low volatility and represent a limited off-site hazard even in larger quantities (Section 8.12.2.1).

The use of hydrogen gas (1320 gallons) poses a risk of explosion. However, the moderate quantity present and the results of previous modeling of the blast effects of a hydrogen tank explosion demonstrate that any blast effect will be confined to the site will not cause any off-site impacts. The Applicant will be required by Condition of Certification **HAZ- 13** to store the hydrogen cylinders in an area isolated from combustion sources. The tanks and piping that are near potential traffic hazards will be protected from vehicle impact by traffic barriers. Figure 8.12-1 indicates that the hydrogen trailer will be located about 75 feet from the combustion turbine and the combustion turbine generator of the eastern most generating unit.

After removing from consideration those chemicals that fit into Steps 1 and 2, staff continued with Steps 4 and 5 to review the only remaining hazardous materials: sodium hydroxide, sulfuric acid, hydrochloric acid, sodium hypochlorite, petroleum fuels, natural gas, and anhydrous ammonia.

Large Quantity Hazardous Materials

Sodium hydroxide will be present in excess of the Reportable Quantity (RQ) and therefore must be included in the Hazardous Materials Business Plan (HMBP) and the Risk Management Plan (RMP). The amount of Sulfuric Acid stored on site will trigger the RQ as will hydrochloric acid that will be present in RQ every three to five years and at start-up. During the interim periods, HCl stored will be less than the RQ. These materials do not pose a risk of off-site impacts, because they have relatively low vapor pressures and thus spills would be confined to the site, or, as is the case with HCl, they will be used infrequently. Because of public concern at another proposed energy facility in 1995, staff conducted a quantitative assessment of the potential for impact associated with sulfuric acid use, storage, and transportation. Staff found no hazard would be posed to the public. However, in order to protect against risk of fire, an additional Condition of Certification will require the project owner to ensure that no combustible or flammable material is stored, used, or transported within 100 feet of the sulfuric acid tank. It appears from Figure 8.12-1 that there are no combustible materials within 100 feet of the sulfuric acid storage areas in the Water/ Wastewater Treatment Area and the Acid Tank near the south side of the cooling towers. Staff has some concerns regarding the location and description of the ammonia tanks and ammonia unloading area, hydrogen trailer, and the nitrogen tank. It appears that the nitrogen tank is labeled as containing hydrogen (PP) and the hydrogen tank is labeled as containing sodium nitrate (T) in Figure 8.12-1. The ammonia tank and unloading facility is between the nitrogen and hydrogen tanks, less than 50 feet from each of the neighboring tanks. The hazard of the close proximity of tanks with regard to fire and explosive hazard should be mitigated (see condition of certification **HAZ-11**).

The aqueous mixture of sodium hypochlorite will likewise have a low potential to affect the off-site public because its vapor pressure is also low and the concentration of hypochlorite is low (10 percent). In fact, hypochlorite is used at many such facilities as a substitute for chlorine gas, which is much more toxic and much more likely to migrate off-site because it is a gas and is stored in concentrated form. Thus, the use of a water solution of sodium hypochlorite is much safer to use than the alternative, which is chlorine gas. However, accidental mixing of sodium hypochlorite with acids or anhydrous ammonia could result in toxic gases. Given the large volumes of both anhydrous ammonia (24,000 gals) and sodium hypochlorite (8000 gals) proposed for storage at this facility, the chances for accidental mixing of the two - particularly during transfer from delivery vehicles to storage tanks - should be reduced as much as possible. Thus, measures to prevent such mixing are extremely important and will be required as an additional section within the required Safety Management Plan for delivery of anhydrous ammonia. However, staff does note that the Applicant proposes to separate incompatible materials to prevent accidental mixing in the AFC (Section 8.6.3.3) and provide separate containment facilities for each material.

A Spill Prevention Control and Countermeasure Plan (SPCC) is required by Federal Regulations (see LORS above) and will be prepared for these petroleum-containing hazardous materials.

Natural Gas

Natural gas poses a fire and/or explosion risk as a result of its flammability. Natural gas is composed of mostly methane but also contains ethane, propane, nitrogen, butane, isobutane and isopentane. It is colorless, odorless, and tasteless and is lighter than air. Natural gas can cause asphyxiation when methane is ninety percent in concentration. Methane is flammable when mixed in air at concentrations of 5 to 14 percent, which is also the detonation range. Natural gas, therefore, poses a risk of fire and/or explosions if a release were to occur. However, it should be noted that, due to its tendency to disperse rapidly (Lees 1983), natural gas is less likely to cause explosions than many other fuel gases, such as propane or liquefied petroleum gas. While natural gas will be used in significant quantities, it will not be stored on-site. The risk of a fire and/or explosion on-site can be reduced to insignificant levels through adherence to applicable codes and development and implementation of effective safety management practices. In particular, gas explosions can occur in the Heat Recovery Steam Generator (HRSG) and during start-up. The National Fire Protection Association (NFPA 85A) requires:1) the use of double block and bleed valves for gas shut-off; 2) automated combustion controls; and 3) burner management systems. These measures will significantly reduce the likelihood of an explosion in gas-fired equipment. Additionally, start-up procedures will require air purging of the gas turbines prior to start-up, thus precluding the presence of an explosive mixture. The safety management plan proposed by the applicant will address the handling and use of natural gas and significantly reduce the potential for equipment failure due to 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 gas welds. Many failures in older pipelines have also resulted from corrosion. Current codes address this failure mode 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 particularly relevant to the project area 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 insignificant 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, 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, and 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, as well as the January 19, 1995 gas explosion in San Francisco, the safety of

the gas pipeline is of paramount importance. However, it must be noted that those pipelines that failed were older and not manufactured nor installed to modern code requirements.

The natural gas pipeline for the proposed facility will be installed, owned, and operated by the applicant. 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 could 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 (SERA 1993). 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. This results 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.

In the United States, extensive federal and state pipeline codes and safety enforcement minimize the risk of severe accidents related to natural gas pipelines. Recently 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 project owner will be required to develop and implement these plans if the proposal is promulgated as a regulation.

Staff believes the worst case scenario for an off-site natural gas impact is a large rupture of the pipeline caused by improper use of heavy equipment near the pipeline. The applicant will provide an analysis of the likelihood (which is thought to be very low)

of explosion and fire resulting from sparks generated from heavy equipment rupture of the pipeline if the DOT proposal for a pipeline risk management plan becomes regulation. This worst case scenario would not result in significant asphyxiation hazard since natural gas disperses to the atmosphere rapidly when released. The worst case scenario is primarily a safety hazard to construction workers and nearby residences. The project owner will mark the pipeline in conformance with State and Federal regulations to lower the probability the above scenario.

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. (See Conditions of Certification **HAZ-7**, **8**, **9**, & **10**)

Anhydrous Ammonia

Based on the discussion above, anhydrous ammonia and natural gas are the only hazardous materials that may pose a risk of off-site impacts. Anhydrous ammonia will be used in controlling the emission of oxides of nitrogen (NO_x) from the combustion of natural gas in the facility. The accidental release of anhydrous ammonia without proper mitigation can result in very large down-wind concentrations of ammonia gas. Two pressure vessel tanks will be used to store the anhydrous ammonia with a maximum of 10,200 gallons in each. Aqueous ammonia is less likely to cause high down-wind concentrations of ammonia and is generally the preferred form of ammonia to use in populated areas as it minimizes the toxic hazard.

The use of anhydrous ammonia can result in the formation and release of a cloud in the event of a release even without interaction with other chemicals. This is a result of its relatively high vapor pressure and the large amounts of anhydrous ammonia which will be used and stored on-site. Anhydrous ammonia is a gas at ambient temperature and therefore is stored under pressure. The rupture of a pipe, tank, or valve would result in a gas jet of ammonia leaving the containment structure at a high rate. The resultant cooling due to adiabatic expansion will have the effect of lowering the temperature of the containment vessel. However, pursuant to EPA and CAL ARP guidelines, the worst-case off-site consequence analysis did not consider this effect and instead assessed a catastrophic release of the entire contents of the tank.

To assess the potential impacts associated with an accidental release of ammonia, staff typically evaluates where four “bench mark” exposure levels of ammonia gas occur off-site. These include: 1) the lowest concentration posing a risk of lethality, 2,000 PPM; 2) the Immediately Dangerous to Life and Health (IDLH) level of 300 PPM; 3) the Emergency Response Planning Guideline (ERPG) level 2 of 200 PPM, which is also the RMP level 1 criterion used by 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 75ppm. (A detailed discussion of the exposure criteria considered by staff and their applicability to different populations and exposure-specific conditions is

provided in Appendix A of this analysis.) If the potential exposure associated with a potential release exceeds 75ppm at any public receptor, staff will presume that the potential release poses a risk of significant impact. However, staff may also assess the probability of occurrence of the release and/or the nature of the potentially exposed population. Staff may, based on such analysis, determine that the likelihood and extent of potential exposure are not sufficient to support a finding of potentially significant impact.

The AFC (section 8.12.3) and the response to data requests #2 (EAEC 2001p, page 34 and Attachment HM-69) discuss the modeling parameters for a worst case and alternative case accidental release of anhydrous ammonia. The worst-case release in the AFC is associated with a failure of the ammonia storage tank so that it empties within 10 minutes. An alternative scenario is a failure of a supply truck loading hose spilling a specified amount of anhydrous ammonia. In conducting these two scenario analyses, it can be assumed that spilled material would be contained in the covered basin below the storage vessel and below the tanker truck pad. In addition, winds of 1.0 meter per second and atmospheric stability class F would exist at the time of the accidental release. The US EPA SLAB air dispersion model was used to estimate airborne concentrations of ammonia. This model is designed to predict the maximum possible impacts based on distance from the storage tank without regard to specific direction of transport.

The results of this modeling showed that off-site airborne concentrations of ammonia would be above the level the Energy Commission uses for significance (75 ppm) but for a very short distance from the anhydrous ammonia storage tank or the facility fenceline. The applicant estimated that a concentration of 75 ppm or greater would exist at a distance of 1476 feet, an area which includes the open space (fields) to the east, south, and north of the facility, and slightly beyond the Mountain House Road to the west of the facility. No sensitive receptor would experience this concentration unless working in the fields or driving past the facility at the precise time of modeled catastrophic release. The estimated airborne concentration at the Mountain House School (0.9 miles away) is 10 ppm, a level which would not impact even sensitive people (such as asthmatic children) and which many people would not even smell.

Transportation of Hazardous Materials

The transportation of hazardous materials to the facility is of concern to the residents and workers in the surrounding community. In particular, several members of the public expressed concern over the potential for an accident involving a chemical spill during delivery. Hazardous materials including anhydrous ammonia, sulfuric acid, and sodium hypochlorite will be transported to the facility via tanker truck. While many types of hazardous materials will be transported to the site, it is staff's belief that transport of anhydrous ammonia poses the predominance of risk associated with such transport.

To address this concern, staff asked the Applicant to evaluate the risk of an accidental release of anhydrous ammonia while in transport to the project area. If anhydrous ammonia were released from a delivery vehicle (i.e. a tanker truck) during transport, it could result in hazardous ambient concentrations. The extent of impact in the event of such a release would depend on the location and on the rate of dispersion of ammonia vapor from the surface of the anhydrous ammonia pool.

The Applicant prepared an analysis (EAEC 2001v, page 3), which demonstrated that the risk of an accident causing a spill of anhydrous ammonia during transportation from I-205 to the facility (approximately 37 trips per year over a distance of 6 miles) would be below the level of significance as defined by the Energy Commission staff. However, given the plans for development of a new community (Mountain House) along the transportation route and the resultant increase in traffic along this route, the risk of an accident may be increased in the future to a level unknown at this time. Because of the toxicity of anhydrous ammonia and the residential and commercial in-fill anticipated in the future, staff concludes that the risk of exposure to harmful concentrations of anhydrous ammonia during transport to the facility could be significant in the future. Staff therefore believes that the applicant should use the safer aqueous form of ammonia to mitigate any potential future risk.

Staff agrees with the Applicant's transportation analysis, which focused on the project area after the delivery vehicle leaves the main highway. Staff believes that it is appropriate to rely on the extensive regulatory program that applies to shipment of hazardous materials on California Highways to ensure safe handling in general transportation (see the Federal Hazardous Materials Transportation Law [49 U.S.C. §5101 et seq], the US Department of Transportation Regulations [49 C.F.R. Subpart H, §172-700], and California DMV Regulations on Hazardous Cargo). These regulations also address the issue of driver competence.

To address the issue of tanker truck safety, the Applicant stated that anhydrous ammonia would be delivered to the proposed facility only in certified vehicles with a design capacity of 7,500 gallons. These vehicles will be designed to DOT Code MC-330 or MC-331. These are high integrity vehicles designed for hauling caustic materials under pressure such as anhydrous ammonia. Staff has proposed an additional Condition of Certification (**HAZ-11**) to ensure that regardless of which vendor supplies the anhydrous ammonia, delivery will be made in a tanker truck, which meets or exceeds the specifications described by these regulations.

Additionally, the project owner will be required to instruct vendors that only the Energy Commission approved transportation route is allowed (Condition of Certification **HAZ-10**). Thus, no hazardous materials deliveries will pass by the Mountain House School.

It is worth noting that the transportation of similar volumes of hazardous materials on the nation's highways is not unique nor an infrequent occurrence. Based on the environmental mobility, toxicity, quantities present at the site, and frequency of delivery, it is staff's opinion that anhydrous ammonia poses the predominate risk associated with hazardous materials transportation and use at the proposed facility. Based on this, staff concludes that the risk associated with transportation of other hazardous materials to the proposed facility does not significantly increase the risk of impact beyond that associated with transporting anhydrous ammonia.

Seismic Issues

The possibility exists that an earthquake would cause the failure of a hazardous materials storage tank and rupture of the natural gas pipeline. The quake could also cause the failure of the secondary containment system (berms and dikes) as well as

electrically controlled valves, pumps, neutralization systems and the foam vapor suppression system. The failure of all these preventive control measures might then result in a vapor cloud of hazardous materials moving off-site and impacting the 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 heighten the concern regarding earthquake safety

Information obtained after the January 1994 Northridge earthquake showed that some damage was caused to several large storage tanks and smaller tanks associated with the water treatment system of a cogeneration facility. Those 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 in adequately designing and building storage tanks and containment areas as well as the natural gas pipeline in order to withstand a large earthquake. Staff notes that the proposed facility will be designed and constructed to the applicable standards of the Uniform Building Code for Seismic Zone 3, CPUC General Order 112E, and Title 49, California Code of Regulations, section 192.

CUMULATIVE IMPACTS

Staff reviewed the potential for the operation of the East Altamont Energy Center combined with the existing facility of Aqua Chlor; a chlorine repackaging plant located approximately 2.5 miles from the project site to result in cumulative impacts on the population within the area. Projects that could potentially contribute to cumulative impacts are those located in the same geographic area of influence defined as within a 5-mile radius of the proposed power plant. Aqua Chlor stores up to 6,000 pounds of chlorine at their facility. A simultaneous release from this tank and the proposed EAEC tank could cause cumulative impacts, if the migrating clouds merged. Ammonia can form an explosive mixture with chlorine gas. The Applicant has stated that the potential effect of this low-probability event will be modeled, using the modeling protocol for anhydrous ammonia. This modeling will be required prior to certification.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the minority population is less than fifty percent within a six-mile radius of the proposed EAEC (please refer to **Socioeconomics Figure 1** in this Staff Analysis), and Census 1990 information that shows the minority/low income population is less than fifty percent within the same radius. However, there is a pocket of minority persons within six miles that staff has considered for impacts. Based on the Hazardous Materials analysis, staff has not identified significant direct or cumulative impacts resulting from the construction or operation of the project, nor has staff found the potential for disparate impacts to minority populations. Therefore there are no Hazardous Materials environmental justice issues related to this project.

APPLICANT'S PROPOSED MITIGATION

The potential for accidents resulting in the release of hazardous materials is greatly reduced by the implementation of a safety management program, which includes the use of both engineering and administrative controls. Administrative controls include the development and implementation of a Safety Management Plan. Elements of facility controls and the safety management plan are summarized below.

ENGINEERING CONTROLS

Engineering controls help to prevent accidents and releases (spills) from moving off-site and impacting the community by incorporating engineering safety design criteria into the design of the facility. The engineered safety features proposed by the applicant for use at this facility include:

- Construction of dikes, berms, and/or catchment basins in the hazardous materials storage areas to contain accidental releases that might happen during storage or delivery;
- Physical separation of stored chemicals in separate containment areas in order to prevent accidental mixing of incompatible materials which may result in the evolution and release of toxic gases or fumes;
- A secondary containment structure will surround the anhydrous ammonia storage tanks and will be equipped with a roof and a water-spray system to "knock-down" much of the anhydrous ammonia if released accidentally;
- Secondary containment areas will surround other large quantity chemical tanks;
- A sloped containment pad that will drain into a sump placed beneath the tanker truck anhydrous ammonia delivering area; and sumps will be provided for each of the secondary diked areas around each large chemical storage tank.

ADMINISTRATIVE CONTROLS

Administrative controls also help to prevent accidents and releases (spills) from moving off-site and impacting the community by establishing worker training programs, process safety management programs and by complying with all applicable health and safety laws, ordinances and standards.

The worker health and safety program proposed by the Applicant for use at this facility will include (but is not limited to) the following elements:

- Worker training regarding chemical hazards, health and safety issues, and hazard communication;
- The proper use of personal protective equipment;
- Safety operating procedures for operation and maintenance of systems utilizing hazardous materials;

- Fire safety and prevention; and emergency response actions including facility evacuation, and hazardous material spill cleanup.

At the facility, the project owner will be required to designate an individual who has the responsibility and authority to ensure a safe and healthful workplace. The project health and safety professional oversees the health and safety program and has the authority to halt any action or modify any work practice in order to protect the workers, facility, and the surrounding community or in the event that the health and safety program is violated.

A facility Process Safety Management Program is required for the facility. This is a program for the regular inspection and maintenance of equipment, valves, piping, and appurtenances. Additionally, the process safety management program requires that only trained facility personnel are assigned to the transfer and handling of hazardous chemicals.

In order to address the issue of spill response, the facility will prepare and implement an Emergency Response Plan which includes information on: hazardous materials contingency and emergency response procedures, spill containment and prevention systems, personnel training, spill notification, on-site spill containment, prevention equipment and capabilities, etc. Emergency procedures will be established which include evacuation; spill cleanup, hazard prevention, and emergency response.

STAFF'S PROPOSED MITIGATION

The worst-case accidental release scenarios prepared by the Applicant (EAEC 2001v, page 34) assumed that a large leak would occur in the anhydrous ammonia storage vessel thus releasing the entire contents into the air and the basin below the storage vessel, and from transfer hose from a tanker truck onto the ground. Staff believes that the most likely event resulting in a spill would be during transfer from the delivery tanker to the storage tank. Staff therefore proposes a condition requiring development of a Safety Management Plan for the delivery of anhydrous ammonia. The development of a Safety Management Plan addressing delivery of ammonia will further reduce the risk of any accidental release not addressed by the proposed spill prevention mitigation measures and the required Risk Management Plan (RMP). Staff makes this recommendation along with the recommended mitigation of using aqueous ammonia. Because the same issues of ammonia transfer exist for the aqueous form as well, the need to prepare a Safety Management Plan remains.

FACILITY CLOSURE

The requirements for the handling of hazardous materials remain in effect until such materials are removed from the site regardless of facility closure. Therefore, the facility owners are responsible for continuing to handle such materials in a safe manner, as required by applicable laws. In the event that the facility owner abandons the facility in a manner, which poses a risk to surrounding populations, staff will coordinate with the California Office of Emergency Services, Alameda County Environmental Health Department, and the California Department of Toxic Substances Control (DTSC) to

ensure that any unacceptable risk to the public is eliminated. Funding for such emergency action can be provided by federal, state or local agencies until the cost can be recovered from the responsible parties (O.E.S. 1990).

RESPONSE TO PUBLIC AND AGENCY COMMENTS

AGENCY COMMENTS

None received

PUBLIC COMMENTS

G&DK-1 – *Gary and Dolores Kuhn inquired about the amount and the frequency of anhydrous ammonia shipments each week and if an ammonia leak would necessitate a warning and shelter at the Mountain House School.*

The Applicant has stated that anhydrous ammonia will be delivered 37 times per year, less than once per week. The tank truck will have a capacity of 10,000 gallons. The worst case accidental leak analysis showed that if the entire contents of the anhydrous ammonia tank were to spill, the airborne concentration at the school would be about 10 ppm, barely perceptible by smell. No adverse health effects would be expected, even in sensitive children at this level.

J&DH-1 – *Jack and Donna Hayes asked for mandatory routing of anhydrous ammonia shipments to be on Byron Highway only and never past the school.*

Proposed Condition of Certification HAZ-10 requires the Byron Highway route to be used.

JHS-1 – *Mrs. Janice Holly-Sheehan is concerned over the safety of the public and in particular the school children located at Mountain House School, less than 1 mile from the proposed facility.*

Staff has thoroughly evaluated the applicant's proposed handling, storage, and transfer methods for all hazardous materials and in particular anhydrous ammonia and the applicant's off-site consequence analysis. Staff is confident that when implemented, the Applicant's safety program will keep accidental releases to a minimum and keep those, which do occur from impacting the off-site public. Based on the off-site consequence air modeling conducted by the Applicant, the airborne concentration of ammonia at the school during a worst-case catastrophic release would be 10 ppm. Staff's review of the scientific literature on the health effects of ammonia show that some people might be able to smell an odor at this concentration while others would not but that no adverse impacts would occur even in sensitive individuals (such as asthmatic children). While staff would prefer that the facility use the safer aqueous form of ammonia, the Applicant has made a compelling case that the proposed engineering and administrative controls will reduce the risk of the anhydrous form to insignificance. Staff offers this alternative if the Commissioners are dissatisfied with the proposed use of anhydrous ammonia.

G&MG-2 – *Gordon and Marianne Griffith also expressed concern about the potential risks posed to students at Mountain House School.*

Please refer to the response above.

G&MG-3 – *Gordon and Marianne Griffith also expressed concern about the potential risks posed by ammonia and the natural gas pipeline.*

It is doubtful that any ammonia odor will be noticeable at the facility, let alone off-site, during normal operations. The engineering controls designed to mitigate a spill will again restrict any odors to on-site and near-site distances. As stated above, based on the off-site consequence air modeling conducted by the Applicant, the airborne concentration of ammonia at the school during a worst-case catastrophic release would be 10 ppm. Staff's review of the scientific literature on the health effects of ammonia show that some people might be able to smell an odor while others would not but that no adverse impacts would occur even in sensitive individuals (such as asthmatic children). The natural gas pipeline will be constructed, marker, and monitored as per US DOT and California PUC regulations. Staff has also proposed several conditions of certification to further ensure safety of the gas pipeline. This will reduce the likelihood of gas line failure to insignificant levels.

CONCLUSIONS AND RECOMMENDATIONS

Staff's evaluation of the proposed project (with staff's proposed mitigation measures) indicates that hazardous materials use will pose little potential for significant impacts on the public, with the exception of the use of anhydrous ammonia. Staff therefore recommends the use of aqueous ammonia. With adoption of the proposed conditions of certification, the proposed project will comply with all applicable laws, ordinances, regulations and standards (LORS).

In response to Health and Safety Code, section 25531 et seq., the applicant will be required to develop an RMP. To insure adequacy of the RMP, staff's proposed conditions of certification require that the RMP be submitted for concurrent review by EPA, Alameda County, and staff. In addition, staff's proposed conditions of certification require Alameda County to review, and staff to approve, the RMP prior to delivery of any hazardous materials to the facility. Other proposed conditions of certification address the issue of the transportation, storage, and use of aqueous ammonia. While staff recommends the use of the less hazardous aqueous form of ammonia, staff believes that the Applicant should have the opportunity to make a case that the proposed engineering and administrative controls will reduce the risk of the anhydrous form to insignificance.

With adoption of staff's proposed conditions of certification, the project will also comply with Health and Safety Code, section 41700, and it will not pose any potential for significant impacts to the public from hazardous materials releases.

Staff recommends the Energy Commission adopt the proposed conditions of certification, presented herein, to ensure that the project is designed, constructed and

operated to comply with applicable LORS and to protect the public from significant risk of exposure to an accidental aqueous ammonia release.

PROPOSED CONDITIONS OF CERTIFICATION

HAZ-1 The project owner shall not use any hazardous material not listed in Appendix C, below, or in greater quantities than those identified by chemical name in Appendix C, below, unless approved in advance by the CPM. The project owner shall also use aqueous ammonia (29% or less) instead of anhydrous ammonia.

Verification: The project owner shall provide to the Compliance Project Manager (CPM), in the Annual Compliance Report, a list of hazardous materials contained at the facility in reportable quantities.

HAZ-2 The project owner shall provide a Risk Management Plan to Alameda County and the CPM for review at the time the plans are first submitted to the U.S. Environmental Protection Agency (EPA). The project owner shall include all recommendations of Alameda County and the CPM in the final document. A copy of the final plans, including all comments, shall be provided to Alameda County and the CPM once approved by EPA.

Verification: At least sixty (60) days prior to the delivery of either aqueous ammonia, the project owner shall provide the final plans listed above and accepted by Alameda County to the CPM for approval.

HAZ-3 The project owner shall develop and implement a Safety Management Plan for delivery of aqueous ammonia. 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 aqueous ammonia with incompatible hazardous materials.

Verification: At least sixty (60) days prior to the delivery of aqueous ammonia to the facility, the project owner shall provide a safety management plan as described above to the CPM for review and approval.

HAZ-4 The aqueous ammonia storage facility shall be designed to either the ASME Pressure Vessel Code and ANSI K61.6 or to API 620. In either case, a secondary containment basin capable of holding 150% of the storage volume shall protect the storage tank plus the volume associated with 24 hours of rain assuming the 25-year storm as specified in the AFC.

Verification: At least sixty (60) days prior to delivery of aqueous ammonia to the facility, the project owner shall submit final design drawings and specifications for the ammonia storage tank and secondary containment basin to the CPM for review and approval.

HAZ-5 The project owner shall ensure that no combustible or flammable material is stored, used, or transported within 100 feet of the sulfuric acid tank.

Verification: At least sixty (60) days prior to receipt of sulfuric acid on-site, the Project Owner shall provide copies of the facility design drawings showing the location of the sulfuric acid storage tank and the location of any tanks, drums, or piping

containing any combustible or flammable material and the route by which such materials will be transported through the facility.

HAZ-6 The project owner shall require that the gas pipeline undergo a complete design review and detailed inspection every 3 years and every 5 years thereafter.

Verification: At least thirty (30) days prior to the initial flow of gas in the pipeline, the project owner shall provide a detailed plan to accomplish a full and comprehensive pipeline design review in the future to the CMP for review and approval. This plan shall be amended, as appropriate, and submitted to the CPM for review and approval, not later than one year before the plan is implemented.

HAZ-7 After any significant seismic event in the area where surface rupture occurs within one mile of the pipeline, the gas pipeline shall be inspected by the project owner.

Verification: At least thirty (30) days prior to the initial flow of gas in the pipeline, the project owner shall provide a detailed plan to accomplish a full and comprehensive pipeline inspection in the event of an earthquake to the CMP for review and approval. This plan shall be amended, as appropriate, and submitted to the CPM for review and approval, at least every five years.

HAZ-8 The natural gas pipeline shall be designed to meet CPUC General Order 112-D and E and 58 A standards, or any successor standards, and shall be designed to meet Class III service. The pipeline shall be designed to withstand seismic stresses and shall be leak surveyed annually for leakage. The project owner shall incorporate the following safety features into the design and operation of the natural gas pipeline: (1) the pipeline shall be designed and constructed to carry natural gas at a pressure of 1000 psig, (2) butt welds shall be x-rayed and the pipeline shall be pressure tested prior to the introduction of natural gas into the line; (3) the pipeline shall be surveyed for leakage annually according to the operations and maintenance plan to be provided by the applicant (AFC section 6.5); (4) the pipeline shall be marked to prevent rupture by heavy equipment excavating in the area; and (5) valves shall be installed to isolate the line if a leak occurs.

Verification: Prior to the introduction of natural gas into the pipeline, the project owner shall submit design, operation, testing, and route marking specifications to the CPM for review and approval.

Haz-9 The project owner shall provide a risk assessment as proposed by the Office of Pipeline Safety, DOT if the proposed program becomes regulation.

Verification: Prior to the introduction of natural gas into the pipeline, the project owner shall submit design and operation specifications to the CPM for review and approval.

HAZ-10 The project owner shall direct all vendors delivering any hazardous material to the site to use only the route approved by the CPM (Interstate 205 to Grant Line Road to the Byron Bethany road to Mountain Hose Road to the facility). An alternate route may be used following approval by the CPM.

Verification: At least sixty (60) days prior to receipt of any hazardous materials on site, the project owner shall submit to the CPM for review and approval, a copy of the

letter to be mailed to the vendors. The letter shall state the required transportation route limitation.

HAZ-11 The project owner shall ensure that the hydrogen gas storage cylinders are stored in an area out of the plane of the turbines and that no combustible or flammable material is stored within 100 feet of the hydrogen cylinders.

Verification: At least sixty (60) days prior to receipt of hydrogen gas on-site, the project owner shall provide copies of the facility design drawings showing the location of the hydrogen gas cylinders and the location of any tanks, drums, or piping containing any combustible or flammable material and the route by which such materials will be transported through the facility.

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APPENDIX A

HAZARDOUS MATERIAL MANAGEMENT

BASIS FOR STAFF'S USE OF 75 PPM AMMONIA EXPOSURE CRITERIA

Staff uses a health-based airborne concentration of 75 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 EPA and Cal/EPA in evaluating such releases pursuant the Federal Risk Management Program and State Accidental Release Program, it is appropriate for use in staff's CEQA analysis. 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 (ERPGs) 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. CEQA requires permitting agencies making discretionary decisions to identify and mitigate potentially significant impacts through changes 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. Appendix B provides a summary of adverse effects, which might be expected to occur at various airborne concentrations of ammonia.

HAZARDOUS MATERIAL MANAGEMENT
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 min.	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 min.	Protects nearly all segments of general population from irreversible effects
STEL[2]	NIOSH	Adult healthy male workers	35 ppm	15 min. 4 times per 8 hr day	No toxicity, including avoidance of irritation
EEGL[3]	NRC	Adult healthy workers, military personnel	100 ppm	Generally less than 60 min.	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 min. 30 min. 10 min.	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 hr.	No toxicity or irritation on continuous exposure for repeated 8 hr. 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 min.	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) warns 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 Appendix A, Table 1

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NIOSH. 1994. National Institute of Occupational Safety and Health, Pocket Guide to Chemical Hazards, U.S. Department of Health and Human Services, Washington D.C., Publication numbers 94-116.

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Abbreviations for 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

Appendix B

SUMMARY OF ADVERSE HEALTH EFFECTS OF AMMONIA

638 PPM

WITHIN SECONDS:

- Significant adverse health effects;
- Might interfere with capability to self rescue;
- Reversible effects such as severe eye, nose and throat irritation.

AFTER 30 MINUTES:

- Persistent nose and throat irritation even after exposure stopped;
- irreversible or long-lasting effects possible: lung injury;
- Sensitive people such as the elderly, infants, and those with breathing problems (asthma) experience difficulty in breathing;
- asthmatics will experience a worsening of their condition and a decrease in breathing ability, which might impair their ability to move out of area.

266 PPM

WITHIN SECONDS:

- Adverse health effects;
- Very strong odor of ammonia;
- Reversible moderate eye, nose and throat irritation.

AFTER 30 MINUTES:

- Some decrease in breathing ability but doubtful that any effect would persist after exposure stopped;
- Sensitive persons: experience difficulty in breathing;
- asthmatics: may have a worsening condition and decreased breathing ability, which might impair their ability to move out of the area.

64 PPM

WITHIN SECONDS:

- Most people would notice a strong odor;
- Tearing of the eyes would occur;
- Odor would be very noticeable and uncomfortable.
- Sensitive people could experience more irritation but it would be unlikely that breathing would be impaired to the point of interfering with capability of self rescue
- Mild eye, nose, or throat irritation
- Eye, ear, & throat irritation in sensitive people
- asthmatics might have breathing difficulties but would not impair capability of self rescue

22 or 27 PPM

WITHIN SECONDS:

- Most people would notice an odor;
- No tearing of the eyes would occur;
- Odor might be uncomfortable for some;
- sensitive people may experience some irritation but ability to leave area would not be impaired;
- Slight irritation after 10 minutes in some people.

4.0, 2.2, or 1.6 PPM

- No adverse effects would be expected to occur;
- doubtful that anyone would notice any ammonia (odor threshold 5 - 20 PPM);
- Some people might experience irritation after 1 hr.

APPENDIX C

[Attach AFC Supplement B Table HM-2 here.]

LAND USE

Negar Vahidi and Eileen Allen

INTRODUCTION

This land use analysis of the East Altamont Energy Center (EAEC) focuses on two main issues: the project's consistency with local land use plans, ordinances and policies; and the project's compatibility with existing and planned land uses. In general, an electric generation project and its related facilities may be incompatible with existing and planned land uses if it creates unmitigated noise, dust, public health hazard or nuisance, traffic, or visual impacts or when it unduly restricts existing or planned future uses.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

This section describes federal, state, regional, and local land use LORS applicable to the proposed project.

FEDERAL

Federal Aviation Administration (FAA) – Determination Hazard to Air Navigation

The proposed project site is approximately 3 miles southeast of the Byron Airport in Contra Costa County. A portion of the proposed project site is shown to be within the Clear Zone of the Byron Airport (Hodges and Shutt, East Contra Costa County Airport Master Plan Report, Byron, California. May 1986). The FAA has made a Determination of No Hazard to Air Navigation associated with the proposed project. This determination concerns the effect of structures on the safe and efficient use of navigable airspace. Under the provisions of Title 49, United States Code, section 44718 and Title 14 of the Code of Federal Regulations, construction or alteration of a structure in the vicinity of an airport cannot exceed obstruction standards and must comply with proper marking and lighting. Any future construction or alteration associated with project facilities would require a separate notice to the FAA. The FAA's determination does not include temporary construction equipment such as cranes or derricks, which may be used during construction. If the height of the construction equipment exceeds the height of the studied structure, a separate notice must be submitted to the FAA (EAEC 2001n, pages 62-64, and Attachment LU-1).

STATE

Subdivision Map Act (Pub. Resources Code § 66410-66499.58)

The Subdivision Map Act provides procedures and requirements regulating land divisions (subdivisions) and the determining of parcel legality. Regulation and control of the design and improvement of subdivisions, by this Act, has been vested in the legislative bodies of local agencies. Each local agency by ordinance regulates and controls the initial design and improvement of common interest developments and subdivisions for which the Map Act requires a tentative and final map.

Delta Protection Act of 1992

The California Legislature established the Delta Protection Act in 1992 to declare the Sacramento-San Joaquin Delta a natural resource to be protected, maintained, and where possible enhanced for agriculture, wildlife habitat, and recreational activities. The act created the Delta Protection Commission with a mandate to develop a long-term resource management plan for the Delta Primary Zone (Pub. Resources Code § 29700 et seq.). All local government general plans for areas within the Primary Zone are required to be consistent with the Delta Protection Act regional plan for the area. The "Primary Zone" means the delta land and water area of primary state concern and statewide significance which is situated within the boundaries of the delta, but that is not within either the urban limit line or sphere of influence line of any local government's general plan or currently existing studies, as of January 1, 1992. The Secondary Zone consists of areas within the statutory Delta (as defined in section 12220 of the California Water Code) but not part of the Primary Zone. Local plans for land use in the Secondary Zone are not required to conform to the regional plan. The proposed project site exists in the Secondary Zone of the statutory Delta (DPC, 1992).

LOCAL

County of Alameda

Alameda County General Plan

Under California State planning law, each incorporated City and County must adopt a comprehensive, long-term General Plan that governs the physical development of all lands under its jurisdiction. The general plan is a broadly scoped planning document and defines large-scale planned development patterns over a relatively long timeframe.

The General Plan consists of a statement of development policies and must include a diagram and text setting forth the objectives, principles, standards and proposals of the document. At a minimum, a General Plan has seven mandatory elements including Land Use; Circulation; Housing; Conservation; Open Space; Noise and Safety.

Alameda County administers the State required general plan as a group of documents organized by geographic areas and subject matter (Government Code, § 65301).

East County Area Plan

The East County Area Plan (ECAP) is a portion of the Alameda County General Plan. The ECAP was adopted by the Alameda County Board of Supervisors on May 5, 1994 and corrected March 1996 (**FIGURE 1** – ECAP General Plan Diagram). The ECAP provides goals, policies and programs for the physical development for the area designated by the Plan as eastern Alameda County. The Plan addresses specific issues that affect both unincorporated and incorporated areas, but have legal regulatory effect only within currently unincorporated areas. The proposed project site is located within east Alameda County. The project site is not located within a City Limit, Sphere of Influence or Urban Growth Boundary. The project site is designated “Large Parcel Agriculture” as shown on the ECAP Land Use Diagram, adopted May 5, 1994 and amended by Measure D approved by the voters of Alameda County on November 7, 2000. The “Large Parcel Agriculture” description is as follows:

” Large Parcel Agriculture “ designation “requires a minimum parcel size of 100 acres, except as provided in Programs 39A and 40. The maximum building intensity for non-residential buildings shall be .01 FAR (floor-area-ratio), but not less than 20,000 square feet.

A discussion on the public infrastructure requirements under Policy 14A of the amended “Large Parcel Agriculture” is found under the “Alameda County Measure D – Save Agriculture And Open Space Initiative” of this analysis.

Specific ECAP policies applicable to the East Altamont Energy Center project are listed below:

- Policy 75 directs the County to conserve prime soils (as defined by the USDA Soil Conservation Service Land Capability Classification) and Farmland of Statewide Importance and Unique Farmland (as defined by the California Department of Conservation FMMP [Farmland Mapping and Monitoring Program]);
- Policy 76 directs the County to preserve the Mountain House area for intensive agricultural use (Northeastern Alameda County);
- Policy 84 directs the County to give highest priority in areas designated “Large Parcel Agriculture” to agriculture operations;
- Policy 91 requires the County to encourage cities in the East County to adopt policies and programs (such as mitigation fees for the conversion of agricultural lands within city boundaries and on lands to be annexed to a city) to fund the Alameda County Open Space Land Trust for protection of resources and the preservation of a continuous open space system outside the Urban Growth Boundary (County of Alameda, 1996);
- Policy 140A: The County shall recognize the Byron (East Contra Costa County) Airport as a regional resource, and shall work with Contra Costa County to ensure that land uses approved in Alameda County within the Byron Airport’s referral area are compatible with the airport’s operations;
- Policy 199: The County shall require that, where conflicts between a new use and the airport that could interfere with the airport’s operations are anticipated, the burden of mitigating the conflicts will be the responsibility of the new use.

Alameda County Zoning Ordinance

The Alameda County Zoning Ordinance (Title 17 of the Alameda County General Code) establishes land use (zone) districts in the unincorporated area. In each specific land use district: land uses, dimensions for buildings, and open spaces are regulated for the purpose of implementing the general plan of the county, protecting existing development, encouraging beneficial new development, and preventing overcrowding and congestion.

The proposed project site is within an “A” (Agricultural) District (County of Alameda, 2001) (**FIGURE 2** – Zone Map). Agricultural districts or A districts are established to promote agricultural and other nonurban uses, to conserve and protect existing agricultural uses, and to provide space for and encourage such uses in places where

more intensive development is not desirable or necessary for the general welfare (County Zoning Ordinance, Section 17.06.010). Public utility building or uses, excluding such uses as a business office, storage garage, repair shop or corporation yard, would require a conditional use permit (Item J, County Zoning Ordinance Section 17.06.060). Appendix A- Land Use contains a list of the principal uses that are permitted in an A district; conditional uses that are permitted if approved by Alameda County's Zoning Administrator; minimum parcel size specification; and a statement that there are no height limitations in A districts.

Alameda County Measure D – Save Agriculture and Open Space Initiative

Alameda County residents approved "Measure D" in November 7, 2000 as a measure to restrict urban development and protect agricultural lands. Measure D modifies the East County Area Plan (ECAP) portion of the Alameda County General Plan. The measure states:

> "The purpose of this initiative is to preserve and enhance agriculture and agricultural lands, and to protect the natural qualities, the wildlife habitats, the watersheds and the beautiful open spaces of Alameda County from excessive, badly located and harmful development. The measure establishes a County Urban Growth Boundary which will focus urban-type development in and near existing cities where it will be efficiently served by public facilities, thereby avoiding high costs to taxpayers and users as well as to "The purpose of this Initiative is to preserve and enhance agriculture and agricultural the environment. The ordinance is designed to remove the County government from urban development outside the Growth Boundary.

The limitations this measure imposes on the amount and location of development aim at preventing excessive growth and curbing the juggernaut of urban sprawl. The Initiative will reduce traffic congestion, air and water pollution, loss of historic and scenic values and the blighting of existing city centers; and will help maintain a high quality of life in Alameda County."(Measure D, November, 2000)

Measure D redefined the "Large Parcel Agriculture" description for the ECAP from that which was originally adopted by the County Board of Supervisors in 1994 (see the LORS section discussion of the ECAP for the amended "Large Parcel Agriculture" description). The measure also re-designated areas zoned as "Urban Reserve" in the ECAP to "Large Parcel Agriculture. Measure D also amended portions of the ECAP text.

OTHER APPLICABLE COUNTY GENERAL PLANS & ZONING ORDINANCES

Contra Costa County General Plan

A portion of the project's water supply pipelines lie within Contra Costa County on lands designated as "Agriculture" and "Public/Semi-Public." The Contra Costa County General Plan (1995 – 2010), adopted in 1996, expresses the broad goals and policies, and specific implementation measures, which guide the County's decisions on future growth, development, and conservation of resources through the year 2010. In addition

to the seven mandatory elements prescribed by the State, the Contra Costa County General Plan includes a Growth Management Element and a Public Facilities/Services Element. Applicable goals and policies include:

- Privately owned utility corridors may be created on lands designated as Public/Semi-Public (Section 3.7.a – Public and Semi-Public) and are also allowed within agriculturally designated lands.
- Lands designated as agriculture shall not exclude or limit types of agriculture, open space, or non-urban uses (Section 3.7.b – Agriculture) (County of Contra Costa, 1996).

Contra Costa County Zoning Ordinance

The Contra Costa County zoning ordinance (Title 8 of the Contra Costa County General Code) establishes zoning districts and contains regulations governing the use of land and improvement of real property within zoning districts. The Zoning Ordinance implements the land use policies of the Contra Costa County General Plan (County of Contra Costa, 2000).

San Joaquin County General Plan

The objectives of the San Joaquin County General Plan are intended to protect agricultural lands for the continuation of commercial agricultural enterprises, small-scale farming operations, and the preservation of open space. The plan also identifies and classifies agricultural lands with small-scale farming operations and dwellings and seeks to minimize impacts to agriculture from urban development. The County implements its agricultural policies through participation in the FMMP and use of this information in the project planning and approval process (County of San Joaquin, 1995a).

San Joaquin County lands within a 6-mile radius of the project site include lands designated as general agriculture, residential, commercial, public, and parks. Within a 1-mile radius of the project site, San Joaquin County lands are comprised of areas designated as residential and commercial.

<u>Resolution Opposing the Proposed Construction of a Major Power Plant on the Border of San Joaquin County/Alameda County Line</u>

Resolution R-01-406, passed and adopted June 26, 2001, by the San Joaquin County Board of Supervisors, opposes the construction and operation of the East Altamont Energy Center until San Joaquin County's concerns have been addressed or impacts to San Joaquin County are mitigated.

San Joaquin County Development Title

The San Joaquin County zoning ordinance (Title 9 of the San Joaquin County General Code) establishes zoning districts and contains regulations governing the use of land and improvement of real property within zoning districts. The Development Title implements the land use policies of the San Joaquin County General Plan (County of San Joaquin, 1995b).

Mountain House Master Plan

The Mountain House Master Plan follows state guidelines for Specific Plans, though it is called the Master Plan to distinguish it from Specific Plans for smaller areas within the Mountain House community. The Mountain House Master Plan implements the amendment to the San Joaquin County 2010 General Plan which added the Mountain House community to the General Plan. The Master Plan presents plans for land use, infrastructure, environmental resources, public service provisions, objectives, policies, and implementation measures. The Mountain House community is located approximately 8 miles to the north of the proposed project site (County of San Joaquin, 2000).

REGIONAL POLICIES

Association of Bay Area Governments

Typically, associations of governments develop regional goals and policies by considering the applicable land use development plans of the jurisdictions within their region. The State and federal governments have designated the Association of Bay Area Governments (ABAG) as the official comprehensive planning agency for the Bay Area. The association's region includes Alameda, Contra Costa, Marin, Napa, San Francisco, San Mateo, Santa Clara, Solano, and Sonoma Counties, and some of the cities within those counties. ABAG's goals and policies are voluntary, non-binding measures that participating cities and counties are encouraged to implement. They are included in this PSA because of their relevance to urban growth and agricultural land preservation issues in the East Altamont area.

The ABAG Regional Plan provides a policy guide for local development, which includes goals and policies, focused on natural resource protection and management. The policy guide includes specific direction for conservation of ecological resources by encouraging comprehensive land-use planning, establishment of land trusts, purchase of conservation easements and open space, and development of environmentally friendly land uses. The association also encourages the preservation of agricultural resources through delineation of urban growth boundaries and buffer zones, and protection of agricultural production zones and the agricultural land market (ABAG, 1999).

The Association of Bay Area Governments has established a policy framework for future land use decision-making in the Bay Area. It respects the need for strong local control and recognizes the importance of regional comprehensive planning for items of regional significance.

SETTING

SITE AND VICINITY DESCRIPTION

The proposed East Altamont Energy Center (EAEC) is to be built on a 40 acre portion of an approximately 174-acre parcel located near the northeast intersection of Mountain House Road and Kelso Road in unincorporated Alameda County (EAEC 2001p, pages

37-38, and EAEC 2001r, Attachment LU-74). The site is bounded to the north by Byron Bethany Road, which is a two lane road running diagonally northwest to southeast; by Kelso Road to the south, which is a two-lane road running east-west; and to the west by Mountain House Road, which is a two lane road running north-south.

The parcel is currently being used for grazing and to farm oats, alfalfa, and hay crops, and occasionally row crops, such as tomatoes. The site had previously been used for dairy cows. A single-family residence, which would be vacated prior to the construction and operation of the project, currently exists on the property (AFC, pg. 8.4-2).

The site is surrounded by agriculture. It is across the street (Mountain House Road) from the Western Area Power Authority (Western) Tracy substation and major transmission line corridors. No transmission lines cross the subject property. Within 2.5 miles to the southwest of the project site are the Bethany Reservoir, the California Aqueduct and the Delta-Mendota Canal. The project is approximately 1 mile south of the Clifton Court Forebay. Portions of the east slope of the coastal foothills are within the vicinity of the project.

The project site and most of the associated linear facilities are on or adjacent to "Prime Farmland." One-hundred and nineteen (119) acres of the 174-acre parcel that are proposed to remain in agricultural use consist of Prime Farmland as shown on AFC, Figure 8.9-2 *Project Area Agriculture* prepared by CH2MHill. While the site has previously been cultivated for row crops (i.e., tomatoes and the farming of oats, alfalfa, and hay), crops have been removed from the project site and the land has been graded, leaving exposed soil (CDC, 1998; EAEC 2001a, AFC Section 8.9).

LINEAR FACILITIES

The linear facilities for the project include a 0.5-mile 230-kV transmission line in Alameda County; a 1.4-mile natural gas supply line in Alameda County; and a 2.1-mile water supply line in Alameda and Contra Costa Counties following the Byron Bethany Road and the Union Pacific Railroad right-of-way (ROW). All water supply lines proposed for the project exist in zones designated by both Alameda and Contra Costa Counties as either agricultural or public zones.

A new 20-inch natural gas pipeline will be installed along an existing ROW, and will connect to PG&E's main existing pipeline. All gas pipeline alternatives lie within areas designated as Large Parcel Agricultural by Alameda County (County of Alameda, 1996; County of Contra Costa, 1996; EAEC 2001a, AFC Section 8.4).

SURROUNDING LAND USE

Land uses surrounding the site include large parcel agriculture, electric utilities, highways, recreation, an elementary school, a railroad ROW, and water management projects. Specific surrounding uses are described as follows:

- The Tracy substation is located to the southwest of the proposed site, on the north side of Kelso Road, comprising the substation and major transmission line corridors converging into the substation, including:

- One 500 kV line exits north from the substation and two 500 kV lines run south from the substation;
- Four 230 kV lines exit to the north, four 230 kV lines exit to the south, and another two 230 kV lines run east;
- One 69 kV line exits south, and another 69 kV line runs north from the substation.
- Several 230 kV transmission towers are located immediately south of the site along Kelso Road.
- Bethany Reservoir, a State recreation area, is located approximately 2.5 miles to the southwest.
- The California Aqueduct and the Delta-Mendota Canal, are located approximately 2 and 2.5 miles west of the project, respectively.
- Byron Bethany Road, along the water supply line ROW and northern boundary of the site, is designated a Scenic Highway.
- Scattered rural residences associated with agricultural uses, such as single-family dwellings/farmhouses, and ranchette-style housing with farm equipment storage, occur within 1 mile southwest of the project site.
- The Mountain House School, an elementary school (K-8) with 58 students, exists just over 1 mile south of the proposed site. (County of Alameda, 1996; County of Contra Costa, 1996; EAEC 2001a, AFC Section 8.4)
- The Livermore Yacht Club, a 24-slip boating facility, operates a marina approximately 1.5 miles northwest of the project site on Clifton Court Forebay in Contra Costa County.
- Bryon Airport is approximately 3 miles northwest of the site in Contra Costa County.
- Construction for the new town (urban development) of Mountain House is occurring approximately 2 miles southeast of the project site in San Joaquin County.

Grazing and row crop agriculture exists along the project's electric transmission line route from the project site to the Tracy substation on the adjacent property across Mountain House Road (EAEC 2001a, AFC Section 8.4).

The project's natural gas pipelines would cross or enter pastures, stockponds, vineyards, and low-density residential areas with farmhouses and ranchette-style houses in agricultural land use areas. These pipelines would also enter the Delta-Mendota Canal water management area and lie adjacent to the Tracy substation transmission facility (EAEC 2001a, AFC Section 8.4).

The water supply line for the project: would cross agricultural land, pasturelands, and the Delta-Mendota Canal water management area, runs adjacent to Mountain House Road and the Tracy substation, and would enter into the California Aqueduct water management areas (EAEC 2001a, AFC Section 8.4).

IMPACTS

THRESHOLDS OF SIGNIFICANCE

According to Appendix G of the Guidelines to the California Environmental Quality Act (CEQA), a project may have a significant effect on land use if a proposed project would:

- Conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the project adopted for the purpose of avoiding or mitigating an environmental effect;
- Disrupt or divide the physical arrangement of an established community.
- Convert Prime Farmland, Farmland of Statewide Importance, or Unique Farmland to non-agricultural use.

A project may also have a significant impact on land use if it would create unmitigated noise, dust, public health hazard or nuisance, traffic, or visual impacts or when it precludes or unduly restricts existing or planned future uses.

CONSISTENCY WITH LAWS, ORDINANCES, REGULATIONS AND STANDARDS

Public Resources Code § 25525 states that the Energy Commission shall not certify any facility when it finds "that the facility does not conform with any applicable state, local, or regional standards, ordinances, or laws, unless the [Energy] commission determines that such a facility is required for public convenience and necessity and that there are not more prudent and feasible means of achieving such public convenience and necessity. In making the determination, the commission shall consider the entire record of the proceeding, including, but not limited to the impacts of the facility on the environment, consumer benefits, and electric system reliability." In no event shall the commission make any finding in conflict with applicable federal law or regulation. When determining if a project is in conformance with state, local or regional ordinances or regulations, the Energy Commission typically meets and consults with applicable agencies to determine conformity and, when necessary, "to attempt to correct or eliminate any noncompliance" (§ 25523(d)(1)). The laws, ordinances, regulations, standards (LORS) and policies applicable to the project have been analyzed below to determine the extent to which the EAEC is consistent or at variance with each requirement or standard.

Federal Aviation Administration

The FAA has completed an aeronautical study for the EAEC under the provisions of Title 49 United States Code, section 44718 and, Title 14 of the Code of Federal Regulations. This aeronautical study revealed that the proposed EAEC structure does not exceed obstruction standards and would not be a hazard to air navigation (EAEC 2001n, pages 62-64, and Attachment LU-1).

California Land Conservation Act of 1965

The 174 acre subject property does not have a land conservation contract. Also, the property is not within a Williamson Act preserve or a Farmland Security Zone. The linear facilities do not cross Williamson Act preserve lands or a Farmland Security Zone.

Delta Protection Act of 1992

The project site lies within the Secondary Zone of the statutory Delta; therefore it is not required to conform to the state regional land use plan required for the Primary Zone area designated by the Act.

Subdivision Map Act, 1972

Calpine has a purchase option on a 176 acre parcel. The power generation facility would occupy up to 40 acres of the property. A letter received from Adolph Martinelli, Director of the Alameda County Community Development Agency, Planning Department (ACCDA) states that their Agency

> "believes that the existing 174-acre parcel for which the project is proposed is a legally recorded parcel. This land was made a parcel prior to the Subdivision Map Act, and may have existed as a parcel as early as the 1800's. No subdivision of the parcel has been proposed to our knowledge, although our understanding is that the power plant would share the parcel with continued agricultural activities. To, reiterate, ACCDA staff believes this parcel to be a legal parcel, and is preparing a Certificate of Compliance to demonstrate this status. The Certificate of Compliance will be made available to the CEC upon completion (ACCDA, 2001a).

As of the writing of this PSA, staff has not received a copy of the recorded Certificate of Compliance for the subject property and cannot conclude that the land-use issue under this LORS has been resolved.

Alameda County Land Use LORS and policies

Energy Commission staff has reviewed the ECAP; Measure D[1], which modifies the ECAP; and the Alameda County Zoning Ordinance. Staff has identified four policy items that we think are unclear and may warrant further public discussion. These policy items are summarized below:

- The ECAP, as modified by Measure D, restricts urban development beyond the Urban Growth Boundary and protects agricultural lands and open space, which may conflict with the construction of a power plant.
- Measure D prohibits public facilities or other infrastructure in excess of that needed for permissible development, and it is not obvious that these power plants are "needed" to support development in the region.
- Staff is unsure how the project could be considered compatible with Alameda County's "Large Parcel Agriculture" general plan land use designation as amended by Measure D.

[1] Adopted by the Alameda County voters on November 7, 2000

- The power plant project may not conform to the allowable uses for the County's "A" District designation.

Energy Commission staff has reviewed letters dated August 15, 2001 and October 4, 2001 from the Director of the Alameda County Community Development Agency. The letters discuss the County's conclusions regarding the EAEC's compatibility with the ECAP, the provisions of Measure D, and the Alameda County Zoning Ordinance. The Director's August 15, 2001 letter also addressed the status of the site as a legal parcel in accordance to the State Subdivision Map Act.

Pursuant to the four local land use policy items noted above, and the two letters from Alameda County, Energy Commission staff met with the Director of the County's Community Development Agency, Adolph Martinelli, and his staff[2] on November 16, 2001. We discussed a number of specific questions (see Appendix B-Land Use) related to the County's interpretation of its land use LORS and policies for the East County area, and how Measure D is being implemented.

Mr. Martinelli and his staff stated that with respect to Alameda County's land use LORS, an electric power plant falls into a public service infrastructure category, rather than urban development such as a residential subdivision or a manufacturing facility. In the infrastructure context, they believe that an electric power plant use is compatible with agricultural uses.

They acknowledged that given the 1100 MW size of the EAEC, the project will provide electricity beyond that "needed" by the East County area residents and businesses. However, they believe that the ECAP/Measure D language, when applied to energy production, does not have a geographic restriction. Therefore, electricity produced at the EAEC could serve the needs of the East County area and beyond into the larger California electricity market, without conflicting with ECAP/Measure D.

The Commission staff believes that there are a number of reasonable interpretations of the language relevant to new power plant projects in the ECAP, Measure D, and the Alameda County Zoning Ordinance. The applicability of Measure D to a large power plant proposal in an agricultural area with Prime Farmland, seems particularly unclear. While staff still has uncertainties and questions (see Appendix A- Land Use) regarding the EAEC project's conformance with these LORS, including Measure D, we tentatively accept the Alameda County staff's interpretation as one of the reasonable options.

While the Energy Commission is the CEQA lead agency, staff generally defers to local governments' interpretation of their land use LORS and policies. There are two circumstances where staff would not defer:

1) the local agency's LORS interpretation would put the Commission's license in jeopardy; or
2) the local LORS interpretation would lead to the Commission's decision having a factual error.

We have concluded that deferring to Alameda County's interpretations of its land use LORS and policies would not trigger either of the circumstances stated above.

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[2] James Sorenson, County Planning Director, and Bruce Jensen, Senior Planner

Given the County voters' passage of Measure D in November 2000, we anticipate that in staff's upcoming land use PSA workshop, there will be a spectrum of views expressed regarding this project's consistency with Alameda County's land use LORS. We will take written and oral comments from both members of the public and agencies into account before issuing our final analysis.

Conditional Use Permit Findings

The Director of the Alameda County Community Development Agency states in his August 15, 2001 letter that the Zoning Administrator may conditionally approve the proposed project. The conditional use permit requires that the following findings be made:

1. Is the use required by the public need? (Must be found in the affirmative)
2. Will the use be properly related to other land uses and transportation and service facilities in the vicinity? (Must be found in the affirmative)
3. Will the use, if permitted, under all circumstances and conditions of this particular case, materially affect adversely the health or safety of persons residing or working in the vicinity, or be materially detrimental to the public welfare or injurious to property or improvements in the neighborhood? (Must be found in the negative)
4. Will the use be contrary to the specific intent clauses or performance standards established for the District in which it is to be considered? (Must be found in the negative)

At staff's November 16, 2001 meeting with Alameda County staff, Mr. Sorenson of the County Planning staff agreed with Energy Commission staff that if Alameda County was the lead agency for this project, then the County would require a conditional use permit application and the four findings stated above under provisions of its Zoning Ordinance. Mr. Sorenson agreed to the Energy Commission staff's request that the County staff make these findings, which the Commission staff could evaluate and incorporate into its final analysis. We have not yet received these conditional use permit findings from Alameda County.

Other County Land Use LORS and policies

Energy Commission staff has reviewed the LORS of adjacent county jurisdictions and has identified no land use impacts or inconsistencies with San Joaquin or Contra Costa County LORS and policies. The linear facilities extending from the proposed project into Contra Costa County are consistent with the land use designation and zoning for the lands they traverse. No component of the proposed project exists within San Joaquin County and so has no land use impact there.

Consistency with Regional Policies

Association of Bay Area Governments (ABAG)

The applicant is proposing to develop a power generation facility outside of the designated Urban Growth Boundary in an agricultural area that is away from existing urban uses. The conversion of at least 40 acres from an agricultural use to a nonagricultural use (the proposed power plant) including the loss of prime

agricultural land present potential non-conformity issues with ABAG policies. The applicant and the County of Alameda are negotiating a mitigation agreement involving: 1) placing the remainder of the subject property not used for the construction of the power plant into preservation, and 2) either the purchasing of off-site comparable lands or easements nearby at a one-to-one ratio of land lost; or contributing to the Alameda County agricultural land preservation funds. The finalized mitigation agreement would bring the project into compliance with the ABAG Regional Goals and Policies under Preservation of Agricultural Resources.

Staff supports this mitigation approach in principle. As of the writing of this PSA, staff has not received a copy of the final agricultural land conversion mitigation agreement between the applicant and the County of Alameda. Therefore, we have not been able to make a final conclusion regarding the consistency of the project with mitigation, with ABAG's policies.

COMPATIBILITY WITH EXISTING AND PLANNED LAND USES

The project would be constructed on a 40-acre portion of a 174-acre agriculturally designated parcel. The applicant has a purchase option on the property.

Existing land uses in the vicinity of the subject property consist of large acreage agricultural lands and agricultural related operations, the Tracy substation; 69 kV, 230 kV, and 500 kV transmission lines and the California Aqueduct and Delta-Mendota Canal water management areas.

The Tracy substation and the adjacent transmission corridor are operated by the Western Area Power Authority, the Delta-Mendota Canal is operated by the U.S. Bureau of Reclamation and the California Aqueduct is operated by the California Department of Water Resources. These government operated facilities are designated "Major Public" by the ECAP. The ECAP defines the "Major Public" designation as providing for "government–owned regional and subregional facilities such as hospitals, jails, college, civic centers, and similar and compatible uses." (ECAP pg.47, March, 1996).

Staff believes that the project's consistency with: 1) the County's land use designation and zoning for the site; 2) the current development pattern for the area established by the ECAP, as amended by Measure D, is unclear. However, we believe that Alameda County's interpretation and conclusions that the EAEC is an allowed and compatible use are reasonable.

The project's construction would result in the conversion of 40 acres from an agricultural use to a non-agricultural use. It would also involve the loss of land considered "Prime Farmland" by the California Department of Conservation. Staff considers the loss and conversion of agricultural land to be inconsistent with ECAP policies, and potentially a significant impact under CEQA. In order to help offset the project-related impacts from the loss of agricultural land, Calpine, in coordination with Alameda County, has proposed mitigation measures, including:

- Contributing funds to Alameda County for a 1:1 purchase of prime agricultural land for permanent farming use and /or easement purchases;and
- Preservation and enhancement of the remaining 134 acres of the parcel as farmland.

Staff supports the above mitigation approach in principle. We will not be able to come to a final conclusion on whether the potentially significant impact has been fully mitigated until we have reviewed the final compensation/agricultural land preservation agreement between the applicant and Alameda County.

The water supply line and natural gas pipeline alternative alignments would involve use of land currently being used in agricultural production, and would be temporarily affected during construction. The topsoil in these areas would be temporarily removed during the construction period, and permanently converted to non-agricultural use by this project. Soil surface would be returned to the original grades and agricultural use upon completion of construction activities. Therefore, no existing farmlands would be converted to non-agricultural use for the utility corridors. The impacts would be less than significant.

The Mountain House School, located approximately one mile south of the project site, would be sensitive to air quality impacts of the proposed project. Recreational users of Livermore Yacht Club (approximately a mile from the facility) and Bethany Reservoir (more than 2.5 miles from the facility), both of which are over a mile from the project site would be affected by air quality impacts and the visual impacts of the plume from the proposed facility. As a scenic highway less than 0.25 miles from the project site, Byron Bethany Road users would be similarly affected by visual impacts of the facility. The project would not preclude future residents and other users of the Mountain House development located in San Joaquin County from pursuing community activities. These impacts are addressed in greater detail in the AIR QUALITY and VISUAL RESOURCES Sections of the PSA. Overall, however, proposed project construction and operation activities would not preclude recreational land uses on nearby lands.

Staff believes that the EAEC is compatible with existing and planned land uses in the East Altamont area. This conclusion is tentative, based on staff's review of correspondence and a meeting with Alameda County staff regarding the project's conformance with the County's land use LORS, and the applicant's proposed mitigation for the conversion and loss of prime farmland. Staff will be able to reach a final conclusion for the FSA after taking various parties' written and oral PSA comments into account, and reviewing the final mitigation agreement.

CUMULATIVE IMPACTS

Land Use Table 1 displays the reasonably foreseeable development projects within a 6-mile radius of the project site.

Land Use Table 1
Reasonably Foreseeable Development Projects

	Size	Location	Jurisdiction	Status

Development				
Old River Specific Plan	1,000 acres	North of I-205 and southeast of the EAEC site	San Joaquin County	Community meetings have been held regarding what would be a commercial/industrial development. The plan is under consideration as an amendment to the San Joaquin County General Plan.
Auto Auction Facility	200 acres	Patterson Pass Road Business Park	San Joaquin County	Under review by San Joaquin County.
Mountain House community	5,000 acres	Approx. 1 mile east of the EAEC site, bounded to the west by the Alameda County Line, to the east by Mountain House Parkway and between I-205 to the south and the Old River to the north.	San Joaquin County	Phasing for the Specific Plan I has begun with construction of the Mountain House Community Service District's water treatment plant, site grading, and laying of infrastructure on the site property.
Catellus Project	Unknown	Approx. 5 miles southeast of the EAEC site, between I-205 and Grant Line Road, west of Lammers Road	City of Tracy	Application for annexation to the City of Tracy to be filed.
Bright Development	160 acres	Approx. 6 miles to the southest, bounded by Lammers Road to the east, I-205 to the north, and 11th Street to the south.	City of Tracy	Application for annexation to the City of Tracy filed.
Tracy Gateway	538 acres	Approx. 4.5 miles to the southeast, along I-205	City of Tracy	Application for annexation to the City of Tracy filed and in Draft EIR process.
Califia community	6,800 acres	Approx. 8 miles east of the EAEC, near Lathrop in western San Joaquin County ..	City of Lathrop	Lathrop has annexed the property; envirronmental permitting process is in progress. Grounbreaking is expected in 2004.
Tracy Peaker Project	9 acres	Approx. 8 miles southeast of the EAEC site, in San Joaquin County, south of Schulte Road and west of Lammers Road	San Joaquin County	Under the 4-month CEC review process, PSA pending.
FPL Tesla Power Project	25 acres	Aprox. 5.5 miles south of the EAEC site, in Alameda County, just north of the Tesla Substation on Midway Road	Alameda County	Under the 12-month CEC review process, in Data Adequacy.
Source: TPP, 2001; San Joaquin County, 2000; San Joaquin County, 2001; EAEC, 2001; FPL Tesla, 2001; HDR, 2001; Lombardo, 2001.				

As shown in **LAND USE Table 1** above, significant amounts of development are occurring in San Joaquin County, including large areas west of the City of Tracy in the process of applying for annexation to the city. These developments can be characterized as primarily mixed-use with residential, commercial, and light industrial sectors. The size of the proposed EAEC remains small relative to the other proposed projects in the area, but combined with the other projects contributes to a regional loss of agricultural land and open space.

The EAEC in combination with other proposed projects in the project area and region are expected to contribute to a regional loss of open space and agricultural land. Without mitigation in the form of open space and agricultural land preservation and land trusts the project presents a significant cumulative impact on agricultural resources and open space. The land preservation agreement being negotiated between the applicant and the County of Alameda may help to mitigate the impacts of this project to a less than significant level.

The proposed project is not expected to make a significant contribution to regional impacts related to new development and growth, such as population inmigration, the resultant increased demand for public services, and expansion of public infrastructure such as water pipelines to serve residential development.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the minority population is less than fifty percent within a six-mile radius of the proposed East Altamont Energy Center (please refer to Socioeconomics Figure 1 in this Staff Analysis), and Census 1990 information that shows the minority/low income population is less than fifty percent within the same radius. However, there is a pocket of minority persons within six miles that staff has considered for impacts. Based on the land use analysis, staff has not identified significant direct or cumulative impacts resulting from the construction or operation of the project, and therefore there are no land use environmental justice issues related to this project.

FACILITY CLOSURE

At some point in the future, the proposed facility would cease operation and close down. At that time, it would be necessary to ensure that closure occurs in such a way that public health and safety and the environment are protected from adverse impacts.

The planned lifetime of the EAEC is estimated at 30 years. At least twelve months prior to the initiation of decommissioning, the Applicant would prepare a Facility Closure Plan for Energy Commission review and approval. This review and approval process would be public and allow participation by interested parties and other regulatory agencies. At the time of closure, all applicable 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 fall under the authority of the Energy Commission.

There are at least two other circumstances under which a facility closure can occur, unexpected temporary closure and unexpected permanent closure. Staff has not identified any LORS from a land use perspective that the applicant would have to comply with in the event of unexpected temporary closure or unexpected permanent closure of the EAEC.

RESPONSE TO PUBLIC AND AGENCY COMMENTS

ALAMEDA COUNTY COMMUNITY DEVELOPMENT AGENCY

Letter dated August 15, 2001

Alameda County notes the project's consistency with: 1) the County's draft agreement with the applicant for mitigation of the conversion and loss of prime farmland; 2) the County's general plan land use designation and zoning for the site; and 3) the current

development pattern for the area established by the ECAP, as amended by Measure D. The County staff also believes that the existing 174 acre parcel for which the EAEC is proposed is a legal parcel.

Staff has addressed the items in the County's August 15, 2001 letter in the PSA section "Alameda County Land Use LORS and policies", which is contained in the larger section headed "Consistency with Laws, Ordinances, Regulations, and Standards".

Letter dated October 4, 2001.

1. The County's letter summarizes the County's current efforts related to reaching a mitigation agreement with the applicant for the loss and conversion of prime farmland.

   Response: Staff has addressed the items in the County's October 4, 2001 letter in the PSA section headed "Compatibility with Existing and Planned Uses".

2. The letter summarizes the County's requirements for Calpine to submit a written program specifying measures to ensure the continuing agricultural productivity of lands adjacent to, and on the same parcel as the proposed EAEC site. This program must be submitted to the County Planning Director prior to the issuance of grading or building permits.

   Response: Staff has incorporated the County's requirement into **LAND-1**. *Calpine/the project owner must also submit this written program to the Energy Commission's Compliance Project Manager for review and approval.*

GARY AND DELORES KUHN

G&DK-2a: The County has designated the site "Agriculture" in its General Plan, whereas the EAEC project is not agricultural and is inconsistent with the General Plan. Productive agricultural land in California is diminishing due to projects like the EAEC.

Response: Staff has addressed the item regarding General Plan consistency in the PSA section "Alameda County Land Use LORS and policies", which is contained in the larger section headed "Consistency with Laws, Ordinances, Regulations, and Standards, and in Appendix B – Land Use.

Staff has addressed the item regarding the conversion and loss of productive agricultural land in the PSA section headed "Compatibility with Existing and Planned Uses".

G&DK-2c: Calpine has a lease/option on a piece of property that is adjacent to the EAEC site. This area is also zoned agricultural, whereas Mr. and Ms. Kuhn are concerned that the property will be rezoned to permit more industrial uses.

Response: The Commission staff has analyzed the land use impacts of the project on a 174 acre parcel, of which 40 would be used for the power plant and related temporary staging areas. The remaining acreage is the subject of an agricultural land preservation agreement that Alameda County is pursuing with Calpine.

Staff is not aware of any County plans to rezone land surrounding the power plant site. The County has some fairly stringent regulations regarding the use of agricultural land, which makes rezoning for industrial use in the East Altamont area seem unlikely. The County staff considers the power plant to be service related infrastructure to help meet the electricity needs of the East County region, as well as the greater Bay Area. The project's consistency with the County's regulations is discussed in the PSA section "Alameda County Land Use LORS and policies", which is contained in the larger section headed "Consistency with Laws, Ordinances, Regulations, and Standards, and in Appendix B – Land Use.

CONCLUSIONS

1. Staff believes that the project's consistency with: 1) the County's land use designation and zoning for the site; and 2) the current development pattern for the area established by the ECAP, as amended by Measure D, is unclear. However, we have tentatively concluded that Alameda County's interpretation and conclusions that the EAEC is a consistent, and allowed use are reasonable.

2. Staff supports the County's efforts to reach a mitigation agreement with the applicant regarding the conversion and loss of productive agricultural land, which is a potentially significant impact. We agree with the mitigation approaches of: 1) preserving the remaining acreage on the site for permanent farming; and 2) 1:1 off-site compensation through the applicant's contribution of funds to the County for purchasing productive farmland or easements. We will need to review the final agreement in order to be able to reach a conclusion as to whether the potentially significant impact under CEQA has been mitigated to a level of insignificance.

3. Staff needs to receive the County's conditional use permit findings in order to determine whether the project conforms with the permitted uses in the County's "A" District (agricultural) District.

4. The project would not disrupt or divide the physical arrangement of an established community. The communities of Byron in Contra Costa County and Mountain House in San Joaquin County are approximately 3 miles away from the subject property.

5. The project would not preclude or unduly restrict existing or planned land uses. The project would not preclude or unduly restrict the conducting of agricultural land uses on neighboring properties or the operation of the federal and state government facilities across the street from the subject property.

6. With mitigation, operation of the project would not cause any significant noise, dust, public health, traffic, or visual impacts to nearby land uses, nor would the operation of the EAEC contribute substantially to any cumulative land use impacts.

Pending receipt of Alameda County's conditional use permit findings, and the County's final agricultural land mitigation agreement with the applicant, at this time staff is not able to make a recommendation for certification. If the project is certified, staff

recommends that the Commission adopt the following proposed Condition of Certification.

PROPOSED CONDITION OF CERTIFICATION

LAND-1 The project owner shall submit an agricultural mitigation plan to the CEC Compliance Project Manager (CPM) for approval. The plan shall specify measures to be taken to ensure the continuing quality and viability of agricultural land and operations. The agricultural mitigation plan shall:

1) describe the long-term management including funding, endowment, maintenance, and monitoring.

2) explain how the project owner is mitigating for the conversion of 40 acres of agricultural land to a nonagricultural use for the construction of the power generation facility.

3) include details as to how the on-site preservation of agricultural land on the subject property not converted for the power generation facility (134 acres approx.) is to occur.

4) explain the project owner's off-site mitigation involving one or both of the following: 1) the purchase of comparable lands or agricultural conservation easements near agricultural lands at a one-to-one ratio of agricultural land converted by the applicant; or 2) the applicant's payment of monies to a County of Alameda trust fund used for the purpose of purchasing agricultural mitigation land or easements.

Protocol: The project owner shall submit the mitigation plan for the project, to the Director of the Alameda County Community Development Agency for review and comment, if applicable. The Director shall have 30 calendar days to review and provide written comments to the CPM for review and approval. The 30-calendar day review period shall start upon the submittal of the mitigation plan to the Director by the project owner.

Verification: Sixty (60) days prior to the start of site mobilization, the project owner shall provide the CPM with the finalized agricultural mitigation plan. The final plan shall include a copy of any final agreement signed between the project owner and the County of Alameda, American Farmland Trust or other agency or non-profit organization that is publicly recognized and authorized to hold agricultural conservation easements for approval by the CPM.

The project owner shall provide to the CPM in a monthly compliance report, a copy of the executed agricultural conservation easements and/or receipt for the payment of monies to an agricultural land mitigation trust account to demonstrate the applicant's fulfillment of their mitigation requirement for approval, if applicable.

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APPENDIX A –LAND USE

Principal Uses (Section 17.06.030)

The following principal uses are permitted in an A district:

"A. On a building site, one one-family dwelling or one-family mobilehome either constructed after September 15, 1971, and issued an insignia of approval by the California Department of Housing and Community Development and permanently located on a permanent foundation system, or constructed after July 15, 1976, and issued an insignia of approval by the U.S. Department of Housing and Urban Development and permanently located on a foundation system;

B. Crop, vine or tree farm, truck garden, plant nursery, greenhouse apiary, aviary, hatchery, horticulture;

C. Raising or keeping of poultry, fowl, rabbits, sheep or goats or similar animals;

D. Grazing, breeding or training of horses or cattle;

E. Winery or olive oil mill;

F. Fish hatcheries and rearing ponds;

G. Public or private riding or hiking trails;

H. One secondary dwelling unit per building site on parcels twenty-five (25) acres in size or larger that are zoned for not more than one dwelling . . ."

(Ord. 99-2 § 1; Ord. 93-33§2 (part); prior gen. code § 8-25.2)

Conditional Uses--Zoning Administrator (Section 17.06.040).

In addition to the uses listed in Sections 17.52.480 and 17.52.510, the following are conditional uses and shall be permitted in an "A" district only if approved by the zoning administrator, as provided in Sections 17.54.130 and 17.06.010:

A. Additional dwellings for persons employed in the agricultural use of subject property and the families of those persons, and/or living quarters for farm laborers, when found by the zoning administrator to be necessary to the farming operation;

B. Outdoor recreation facility;

C. Killing and dressing of livestock, except when accessory as specified in Section 17.06.050;

D. Public or private hunting of wildlife or fishing, and public or private hunting clubs and accessory structures;

E. Packing house for fruit or vegetables, but not including a cannery, or a plant for food processing or freezing;

F. Flight strip when accessory or incidental to a permitted or conditional use;

G. Hog ranch;

H. Drilling for and removal of oil, gas or other hydrocarbon substances;

I. Radio and television transmission facilities;

J. Public utility building or uses, excluding such uses as a business office, storage garage, repair shop or corporation yard;

K. Boarding stables and riding academies;

L. Administrative offices accessory to the principal use on the premises including activities by the same occupancy which are not related to the principal use providing such activities not so related are accessory to the administrative office activity;

M. Occupancy of one mobile home by persons directly related to an on-site agricultural pursuit on a parcel containing a minimum of one hundred (100) acres where there is no single-family dwelling or on a parcel containing a minimum of two hundred (200)

acres where it can be demonstrated that security cannot be obtained by existing single-family dwelling occupancy; provided, however, that no such conditional use permit shall be issued for a period to exceed three years;

N. Administrative support and service facilities of a public regional recreation district;
O. Privately owned wind-electric generators;
P. Remote testing facility;
Q. Winery or olive oil mill related uses.

(Ord. 2000-53 § 1 (part); Ord. 99-26 § 1 (part); Ord. 94-40 § 1; Ord. 3-33 § 2 (part); prior gen. code § 8-25.3)" (Emphasis added).

Minimum Parcel Size

Section 17.06.060 of the County Zone Ordinance states "Every use in an" A " district shall be on a building site having an area not less than one hundred (100) acres."

Height Limitations

"The Alameda County Zoning Ordinance specifies no height limitation for the "A"-Agricultural Zone, therefore no variance process would apply." (Alameda County Community Development Agency, 2001a)

APPENDIX B – LAND USE

In the course of preparing the land use analyses for the East Altamont Energy Center (EAEC) project and the Tesla Power Project (TPP), staff has some questions regarding the projects' consistency and conformance with the ECAP, Measure D, and the County Zoning Ordinance. Energy Commission staff has requested clarification from the County of Alameda on these matters.

ECAP POLICIES

Policy 1, pg. 1 (Subregional Planning)
Policy 15, pg. 5 (Urban and Rural Development)
Policy 17, pg. 6 (Urban and Rural Development)
Policy 1 states that "[t]he County shall identify and maintain an Urban Growth Boundary that defines areas generally suitable for **urban development** and areas generally suitable for long-term protection of natural resources, agriculture and other productive resources, recreation, buffers between communities, and public health and safety. The Urban Growth Boundary is intended to be permanent and to define the line beyond which urban development shall not be allowed." Policy 17 further provides that "[t]he County shall approve **urban development** only if it is located within the Urban Growth Boundary."

Policy 15 states that "[t]he County shall phase development to minimize premature loss of agricultural land. Agricultural land may be **urbanized** where conversion is a part of phased growth planned to avoid discontinuous (leap-frog) development."

Both projects are to be located on agricultural land in an unincorporated area beyond an Urban Growth Boundary and do not appear to be part of any phased growth plan. The ECAP definition for "urban development" includes industrial land uses, which would seem to include power plants. Therefore, staff has the following questions:

1. Does the County consider a power plant to be part of "urban development"?
2. What is the County's definition of "urbanized"?
3. Does the County see any potential conflicts with ECAP policies 1, 15, and 17? If not, what is the rationale?

Policy 56 (Sensitive Lands and Regionally Significant Open Space)
This policy stipulates that the County is to "preserve open space areas for the protection of public health and safety, provision of recreational opportunities, production of natural resources (e.g., agriculture, windpower, and mineral extraction), protection of sensitive viewsheds,…"

Both projects are proposed to be located within agricultural/open space areas. Therefore, staff has the following question:

4. Is a power plant a use consistent with preservation of "open space areas" as presented under this policy and defined in the ECAP? If yes, please explain the

rationale.

Policy 76, pg. 20 (Sensitive Lands and Regionally Significant Open Space)
Policy 76 states that "[t]he County shall preserve the Mountain House area for intensive agricultural use." Intensive agricultural use, according to the ECAP definition, refers to "high yield agricultural production including vineyards, orchards, and row crops as distinguished from low-intensity agriculture such as cattle and horse grazing."

The Mountain House area includes the proposed site for the EAEC project, and staff does not understand how the power plant would be consistent with the Policy 76 requirement to preserve this area for intensive agricultural use.

5. Does the County believe that the EAEC would conform with Policy 76? If yes, please explain the rationale.

Policy 81A, pg. 21 (Sensitive Lands and Regionally Significant Open Space)
This policy provides that the County shall permit agricultural processing facilities and limited agricultural services that support local agricultural activities and are not detrimental to long-term agricultural use in the "A-100," "A-160," and "A-320" Districts. The proposed projects are to be located within the A-100 and A-160 Districts, and do not seem to qualify as either "agricultural support facilities" or "limited agricultural services that support local agricultural activities."

6. How would a power generation facility be a consistent use within the "A" District according to this general plan policy?

Policy 89, pg. 22-23 (Sensitive Lands and Regionally Significant Open Space)
This policy identifies that the County shall not approve cancellation of Williamson Act contracts within or outside the Urban Growth Boundary except where "findings" can be made in accordance with state law.

The Tesla project will require the purchase of a 60-acre portion of a 160-acre property that is within a Williamson Act contract. The applicant is not proposing to cancel the Williamson Act contract. The project is to be located in the unincorporated area beyond an Urban Growth Boundary.

7. Is a power plant a consistent use under a Williamson Act contract and consistent with Policy 89? If so, please explain the rationale.

Policy 93, pg. 23 (Sensitive Lands and Regionally Significant Open Space)
Policy 93 states that the "County shall approve divisions of agricultural parcels only when the criteria set forward in Table 9 Standards for Subdivision and Site Development Review for Agricultural Parcels are met."

At this time, the Tesla project will involve the purchase of a 60-acre portion of a 160-acre property within the County's A-160 District for the building of the power plant which may require the filing of a parcel map.

8. Please explain if the County requires the filing of a parcel map and if the potential 60-acre parcel division would be consistent with Table 9 and the A-160 zone district.

MEASURE D-AMENDED POLICIES

Policy 14A, pg. 3 (East County Area Plan Amendments)
Policy 14A states that "The County shall not provide nor authorize public facilities or other infrastructure in excess of that needed for permissible development consistent with the Initiative. This Policy shall not bar new, expanded, or replacement infrastructure necessary to create adequate service for the East County."

Both proposed power-generating facilities are to be constructed as privately owned and operated merchant power plants that will generate power for commercial sale, and there is no guarantee that the plants will sell power to buyers within Alameda County's designated east county area. Energy Commission staff cannot say with certainty that these power plants will necessarily satisfy any "needs" within the east county.

9. Does the County consider a merchant power plant to be a "public utility"?
10. If yes, does the County consider the proposed projects a conflict with the parameters for a public utility presented in Policy 14A? If not, what is the rationale?

"Large Parcel Agriculture" description, pg. 8
Policies 81A & 85, pg. 5
The ECAP general plan land use designation for both project sites is "Large Parcel Agriculture." When the voters approved Measure D on November 7, 2000 they amended the description of "Large Parcel Agriculture" include the following language:

"Subject to the provisions of the Initiative, this designation permits agricultural uses, agricultural processing facilities …, limited agricultural support service uses …, secondary residential units, visitors-serving commercial facilities …, recreational uses, public and quasi-public uses, solid waste landfills and related waste management facilities, quarries, windfarms and related facilities, utility corridors, and similar uses compatible with agriculture."

It is important to note that the Measure D amendment deleted from this list of allowable uses "other industrial facilities appropriate for remote areas and determined to be compatible with agriculture."

Policies 81A and 85 restate that areas designated "Large Parcel Agriculture" may include agricultural processing facilities, limited agricultural support service uses that primarily support Alameda County agriculture, and limited agriculture enhancing commercial uses that primarily support the area's agricultural production.

Measure D allows for "utility corridors" in areas designated "Large Parcel Agriculture," but staff has not been able to find a definition for what constitutes a "utility corridor" in either the ECAP or the Alameda County zoning ordinance.

Staff would typically interpret a "utility corridor" to mean a passageway or strip of land for such uses as transmission lines, canals, cable, or large pipelines. Essentially, staff's

understanding is that a utility corridor is a designated land area for the placement of linear facilities. This is different from land area to be used for the siting of a power generation facility. Power generation facilities are often categorized as an "industrial" land use and are required by many local land use regulations to be located in areas designated "industrial" by the City or County.

Therefore, staff has the following questions:

11. Is the County's interpretation of "utility corridor" consistent with staff's? If not, please provide the County's definition of a "utility corridor."
12. Does the County consider a power generation facility to be a use consistent with the amended description for "Large Parcel Agricultural" under Measure D? If yes, please explain.

Policy 89, pg. 5

Policy 89 states that the "County shall not approve cancellation of Williamson Act contracts within or outside the County Urban Growth Boundary except where findings can be made in accordance with state law, and the cancellation is consistent with the Initiative."

The Tesla project involves the purchase of a 60-acre portion of a 160-acre property that is within a Williamson Act contract. The applicant is not proposing to cancel the Williamson Act contract. The subject property is outside of the County Urban Growth Boundary.

13. Is a power plant a consistent use under a Williamson Act contract and consistent with Policy 89 of Measure D? If yes, please explain the rationale.
14. If not, does the County intend to cancel the contract, and does Measure D allow for cancellation of this contract?

Table 9 - Standards For Subdivision And Site Development Review For Agricultural Parcels, pg. 24-25 (Appendix 6)

Table 9 states that the "County shall require all tentative maps in areas designated "Large Parcel Agriculture" or "Resource Management" to identify a building envelope of no more than two acres on each proposed parcel. Also Table 9 provides standards for reviewing proposals to subdivide land designated for agriculture in the East County area.

The Tesla project will involve the purchase of a 60-acre portion of a 160-acre property and may require the filing of a parcel map. The subject property is within the County's "Large Parcel Agriculture" general plan designated area and its "A-160" zone district.

15. Does the County require a parcel map to be filed for this project?
16. Would a potential land division to create a 60 acre parcel be consistent with the "Large Parcel Agriculture" and Table 9 of Measure D and the "A-160" zone district?

NOISE AND VIBRATION

Jim Buntin

INTRODUCTION

The construction and operation of any power plant 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 power plant construction practices, such as pile driving. The ground-borne 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 the East Altamont Energy Center (EAEC) (01-AFC-4), 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).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

FEDERAL

Under the Occupational Safety and Health Act of 1970 (OSHA) (29 U.S.C. § 651 et seq.), the Department of Labor, Occupational Safety and Health Administration (OSHA) has adopted regulations (29 C.F.R. § 1910.95) designed to protect workers against the effects of occupational noise exposure. These regulations list permissible noise exposure levels as a function of the amount of time to which the worker is exposed (see **Noise: 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.

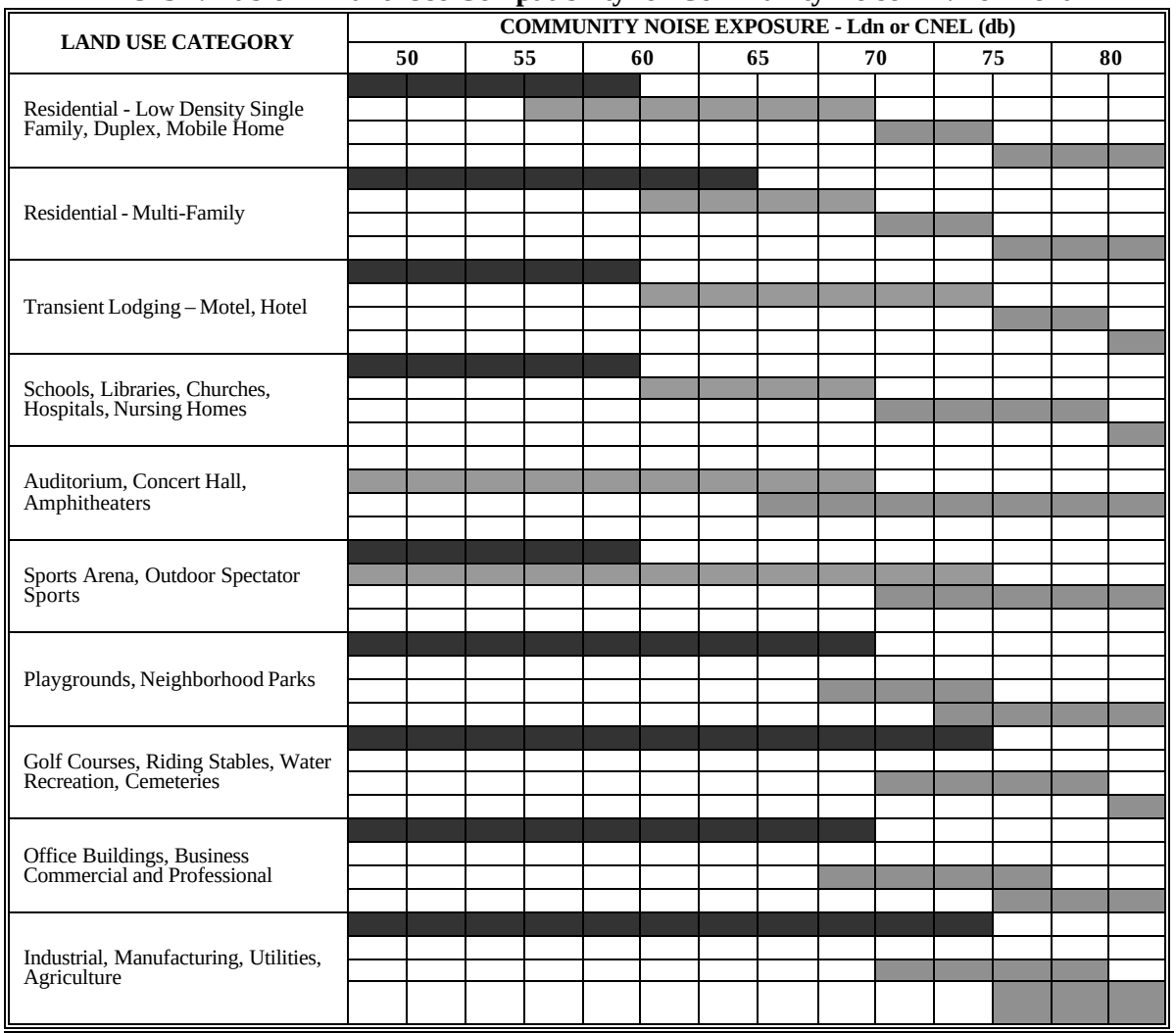
There are no federal laws governing off-site (community) noise.

The Federal Transit Administration (FTA) has published guidelines for assessing the impacts of ground-borne vibration associated with construction of rail projects, which have been applied by other jurisdictions to 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 ground-borne vibration. The FTA measure of the threshold of perception is 65 VdB, 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.

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 land use compatibility guidelines are listed in **NOISE: Table 1**.

NOISE: Table 1 - Land Use Compatibility for Community Noise Environment



	Normally Acceptable	Specified land use is satisfactory, based upon the assumption that any buildings involved are of normal conventional construction, without any special noise insulation requirements.
	Conditionally Acceptable	New construction or development should be undertaken only after a detailed analysis of the noise reduction requirements is made and needed noise insulation features are included in the design.
	Normally Unacceptable	New construction or development should be discouraged. If new construction or development does proceed, a detailed analysis of the noise reduction requirement must be made and needed noise insulation features included in the design.
	Clearly Unacceptable	New construction or development generally should not be undertaken.

Source: State of California General Plan Guidelines, Office of Planning and Research, June 1990.

The State of California, Office of Noise Control, prepared a Model Community Noise Control Ordinance, which provides guidance for acceptable noise levels in the absence of local noise standards. The Model also contains a definition of a simple tone, or “pure

tone," in terms of 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 5 dBA.

Other State LORS include the California Environmental Quality Act (CEQA) and the California Occupational Safety and Health Administration (Cal-OSHA) regulations.

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:

a) 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;

b) exposure of persons to or generation of excessive groundborne vibration or groundborne noise levels;

c) a substantial permanent increase in ambient noise levels in the project vicinity above levels existing without the project; or

d) a 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 c) 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 L_{90} or more at the nearest location where the sound is likely to be perceived.

Noise due to construction activities is usually considered to be insignificant in terms of CEQA compliance if:

1. The construction activity is temporary,
2. Use of heavy equipment and noisy activities is limited to daytime hours, and
3. All feasible noise abatement measures are implemented for noise-producing equipment.

Cal-OSHA

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 the federal OSHA standards (**see NOISE: Appendix A, Table A4**).

LOCAL

Alameda County General Plan Noise Element

The Noise Element of the Alameda County General Plan contains provisions and policies that are intended to minimize noise impacts to the community. The Noise Element refers to an exterior CNEL of 60 dB as being acceptable in residential areas without additional sound insulation.

Alameda County General Ordinance Code

Alameda County has adopted specific noise performance standards for stationary sources in Title 6, Chapter 6.60 of the General Ordinance Code. The noise levels considered acceptable for residential land uses are described by **NOISE: Table 2**.

Noise: Table 2 – Alameda County Noise Standards

Noise Level Descriptor	Daytime Standard, dBA (7 a.m. to 10 p.m.)	Nighttime Standard, dBA (10 p.m. to 7 a.m.)
Median Level (L50)	50	45
Maximum Level	70	65

Each of the above standards is reduced by 5 dBA when applied to simple tone noise, noise consisting primarily of music or speech, or recurring impulsive noise.

Construction noise is exempt from the above noise standards between the hours of 7:00 a.m. to 7:00 p.m. on weekdays, and 8:00 a.m. to 5:00 p.m. on weekends.

Alameda County East County Area Plan Policies

Policies 265, 266 and 267 of the Alameda County East Area Plan require the County to endeavor to maintain acceptable noise levels throughout the eastern part of the county. A noise level of 60 dBA is considered acceptable. The policies also require an acoustical analysis for a project that may result in noise effects.

Contra Costa County General Plan Noise Element

The Noise Element of the Contra Costa County General Plan contains provisions and policies that are intended to minimize noise impacts to the community. The Noise Element exterior noise standard for residential areas is 60 dB DNL.

San Joaquin County Code

Section 9-1025.9 (b.) (1) of the San Joaquin County Code regulates noise from stationary sources. The noise standards that apply to steady-state stationary sources affecting noise sensitive uses are the same as in **NOISE: Table 2**, though expressed in terms of the L_{eq}.

Section 9-1025.9 (c.) (3) of the San Joaquin County Code exempts construction noise from County noise standards during the hours of 6:00 a.m. to 9:00 p.m. Section 9-1025.9 (c.) (7) exempts noise associated with modifications of private and public utilities for maintenance or modifications to their facilities.

SETTING

PROJECT BACKGROUND

The East Altamont Energy center (EAEC) project involves the construction and operation of a 1,100-megawatt (MW) power plant, which is proposed to be located on agricultural land at the northeastern edge of Alameda County.

The new units will consist of three natural gas combustion turbines with heat recovery steam generators and duct burners, and a condensing steam turbine. The EAEC will have a 230 kV switchyard, and will connect to the Western Area Power Administration (Western) substation using a new 0.5 mile-long 230 kV transmission line.

The equipment that has the greatest potential to generate significant noise levels includes the gas and steam turbines, steam generator, duct burners, the auxiliary boiler, pumps, motors, main transformers, and a 19-cell mechanical draft evaporative cooling tower. During construction of the project, pile driving has the potential to produce significant ground-borne vibration levels.

Power Plant Site

This site is located within Alameda County, adjacent to San Joaquin and Contra Costa Counties. Land uses in the project vicinity include agricultural, industrial and school uses.

The EAEC will be constructed on currently vacant agricultural land. The nearest noise sensitive uses are homes on nearby agricultural parcels, the Livermore Yacht Club, and a school, all located at distances 0.5 miles or more from the project site.

Linear Facilities

The EAEC will connect with the electrical grid at a new switchyard located on the plant site. Approximately 0.5 miles of new 230 kV transmission line will connect the switchyard to the Western substation, over agricultural lands.

The project will include construction of approximately 1.4 miles of new natural gas supply line, 4.6 miles of new recycled water supply line, and 2.1 miles of new water supply line. These facilities will be located primarily on agricultural lands, but may pass in close proximity to houses. The natural gas and recycled water lines will be constructed in part on lands within the adjoining counties.

EXISTING NOISE LEVELS

In order to predict the likely noise effects of the project on adjacent sensitive receptors, the applicant commissioned ambient noise surveys of the area. The surveys were conducted in January and October of 2001. The noise surveys were conducted using Bruel & Kjaer sound level meters meeting the requirements of the American National Standards Institute (ANSI) for Type 1 sound level measurement systems. The measurements were performed at heights of approximately five feet above ground level to simulate the average height of the human ear (EAEC 2001, AFC § 8.5-5, EAEC 2001b).

The applicant's noise survey monitored existing noise levels at the following four off-site monitoring locations, which are shown by **NOISE: Figure 1**:

1. Nearest residence (Franco), SE of project site, on Kelso Road
2. Nearest residence NE of project site, on Lindeman Road
3. First residence south of Kelso Road on Mountain House Road (also represents school site)
4. Adjacent to residences at Livermore Yacht Club

NOISE: Table 3 summarizes the ambient noise measurement results (EAEC 2001, AFC § 8.5.2.2, EAEC 2001b).

Noise Table 3: Summary of Measured Noise Levels

Measurement Sites	Measured Noise Levels, dBA		
	Quietest Nighttime Hours		CNEL
	L_{eq}	L_{90}	
1 (January 2001)	34 - 54	29 - 34	57
1 (October 2001)	36 - 48	30 - 40	59*
2 (January 2001)	42 - 48	27 - 40	57
2 (October 2001)	43 - 57	35 - 48	56*
3	32 - 42	30 - 32	55 - 60*
4	36 - 40	32 - 33	55 – 60*
* Energy Commission staff calculation or estimate			

In the Air Quality section of the AFC, the applicant notes that there is a consistent high-speed wind pattern in the project area, where the wind speeds exceed 3.7 meters/second (m/s) (8.3 mph) 58% of the time. The wind direction is predominantly from the west-southwest and west. It is further noted that this condition occurs mostly during the spring, summer and fall. In winter, when the ambient noise monitoring was conducted for this project, wind speeds are lower, and the wind direction is from the east. The AFC does not indicate whether the high-speed wind pattern occurs during nighttime hours.

High-speed wind conditions can affect noise in two ways: Ambient noise levels may increase due to wind interaction with vegetation and structures, and project-related sound may be propagated downwind.

The noise level measurements conducted in October 2001 were intended to address the potential for wind to affect background noise levels, and included the effects of wind speeds between 1 mile per hour at nighttime and above 10 miles per hour during the late afternoons. The measured background noise levels in October were slightly higher than those measured in January, and exhibited more variability, probably as a result of the wind interaction with structures.

In general, the noise environment in the immediate vicinity of the existing plant can be described as relatively quiet, especially at night. During the spring, summer and fall, the prevailing wind may result in elevated noise levels. In the winter, ambient noise levels are expected to be quite low.

The noise environment in the immediate vicinity of the project site is therefore dominated by noise from the wind, distant traffic, and agricultural activities.

IMPACTS

Noise impacts associated with the project can be created by short-term construction activities, and by normal long-term operation of the power plant.

PROJECT SPECIFIC IMPACTS — CONSTRUCTION

Community Effects

General Construction Noise

Construction noise is usually considered a temporary phenomenon. In this case, the construction period for the EAEC would occur over a 2-year period. Construction of an industrial facility such as a power plant is typically noisier than permissible under usual noise ordinances. In order to allow the construction of new facilities, construction noise during certain hours is commonly exempt from enforcement by local ordinances. Alameda County regulates the permissible hours of construction, but does not have any specific noise limits during those hours.

The applicant has prepared an analysis of construction noise impacts, listing predicted noise levels due to specific types of equipment and of generalized construction activities. The construction noise analysis results are summarized for the most-affected receptor locations during the busiest periods of construction in **NOISE: Table 4**.

NOISE: Table 4 - Construction Noise Level Predictions

Construction Phase	Predicted Average Noise Level, dBA	
	Site 1 Nearest home to SE: 2,700 feet away	Site 2 Nearest home to NE: 3,200 feet away
Site Clearing and Excavation	54	53
Pouring Concrete	43	42
Erecting Steel	52	51
Mechanical	52	51
Cleanup	54	53

The predicted construction sound levels would result in cumulative noise levels within the range of the ambient daytime noise level conditions at both of the above receptor locations. These increases would be perceptible during normally quiet hours, and would be of a temporary nature. The unmitigated increases in ambient noise levels due to construction are potentially significant. However, because construction will be restricted to daytime hours by Condition of Certification **NOISE-8**, the noise effect of construction is considered to be insignificant

The noise levels shown in **NOISE: Table 4** do not include the contribution of pile driving, as the applicant has indicated that pile driving may not be needed. If pile driving were needed, noise levels could be approximately 70 dBA at the nearest residence. This level would exceed the range of ambient noise levels in most cases, and is potentially significant. However, pile driving typically occurs over a relatively short period (a few days), and is of a temporary nature. Because construction will be restricted to daytime hours by Condition of Certification **NOISE-8**, the noise effect of pile driving, if it occurs, is expected to be insignificant.

Based upon the potential noise impacts of construction, the Energy Commission staff has recommended the inclusion of three Conditions of Certification (**NOISE-1**, **NOISE-2**, and **NOISE-8**) to monitor and mitigate potential construction and demolition noise impacts.

Because construction activity and related traffic are regulated by the proposed Conditions of Certification, and are of limited duration, potential construction noise impacts to receptors in the EAEC project area are considered to be less than significant.

Pile Driving Vibration

Conventional pile driving produces potentially significant ground-borne vibration at nearby receivers. In this case, the nearest potentially affected receptor is about 0.5 miles from the construction site, which is beyond the range over which pile driving vibration is expected to be potentially significant. Therefore, it is not expected that pile driving, if it occurs, will produce any significant vibration at the nearest receptors.

Steam Blows

Typically, the steam blows during construction and start-up create the loudest noise encountered during the construction phase. Steam blows are necessary after erection and assembly of the feedwater and steam systems because the piping and tubing that comprises the steam path accumulate dirt, rust, scale and construction debris such as weld spatter, dropped welding rods and the like. If the plant were to start up without thoroughly cleaning out the piping and tubing, 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 the heat recovery steam generator (HRSG) or a temporary boiler and allowed to escape to the atmosphere through the steam piping. This flushing action, referred to as a steam blow, is 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.

According to the applicant, un-silenced steam blow noise levels could be as high as 95 dBA at the nearest receiver. With an appropriate silencer, such as a Fluid Kinetics Model TBS 16-AC, or similar, the noise levels could be reduced by 40 to 45 dBA, or to a level ranging from 50 to 55 dBA at the nearest residence (EAEC 2000a). The resulting noise levels would be in the range of ambient noise levels during daytime hours.

The applicant has proposed to mitigate the noise generated from construction steam blows by use of a silencer similar to that described above. Energy Commission staff proposes that any high pressure steam blows be muffled with an appropriate silencer, and that they be performed only during daytime hours to minimize annoyance to residents (see proposed Condition of Certification **NOISE-4** below).

Energy Commission staff further proposes a notification process to make neighbors aware of scheduled steam blows (see proposed Condition of Certification **NOISE-5** below).

Linear Facilities

New off-site linear facilities will include gas and water lines, and a 230 kV transmission line. Noise from these activities will be limited by adhering to the allowable hours of construction as cited in proposed Condition of Certification **NOISE-8**.

The applicant has indicated that horizontal drilling will be required for the new water line under the Delta-Mendota Canal, and that this activity would occur continuously over a period of about two weeks. The noise source associated with this activity would be the engine driving the drill rig. This noise source is potentially significant. The drill rig will be located on the opposite side of the canal relative to the potentially-affected residences. If the drill rig is fitted with adequate mufflers, and the receptors are shielded from the noise from the drill rig by the canal banks, it is not expected that the noise due to horizontal drilling will be significant.

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 (EAEC 2001, AFC § 8.7). To ensure that construction workers are, in fact, adequately protected, Energy Commission staff has proposed Condition of Certification **NOISE-3**.

PROJECT SPECIFIC IMPACTS — OPERATION

Community Effects

The applicant has incorporated noise reduction measures into the design of the project. The applicant intends to achieve compliance with the noise performance standards of the Alameda County Community Noise Ordinance. Compliance with LORS will not prevent a significant impact, since the allowable noise levels would be substantially higher than existing background noise levels.

Power Plant Operation

During its operating life, the EAEC represents essentially a steady, continuous noise source day and night. Occasional brief increases in noise levels would occur as steam relief valves open to vent pressure, or during startup or shutdown as the plant transitions to and from steady-state operation. At other times, such as when the plant is shut down for lack of dispatch or for maintenance, noise levels would decrease.

The primary noise sources anticipated from the facility include the combustion turbines, the auxiliary boiler, steam turbine generator, relief valves, circulation water pumps, cooling towers, and the brine concentrator compressor. The noise emitted by power plants during normal operations is generally broadband, steady state in nature. The resulting hourly average noise levels are typically dominated by the steady-state noise sources.

The applicant performed acoustical calculations to determine the facility noise emissions, and to develop noise mitigation measures. The calculations were based on typical manufacturer noise data for the major equipment planned for the facility (EAEC 2001a, AFC § 8.8.3.4). The modeling assumed that the units would be operated at full load. This is quite conservative, as actual power generation requirements vary with the time of day and electrical demands. The modeling was performed as an iterative process to refine noise mitigation measures and requirements for equipment noise emission factors. Specific noise mitigation measures evaluated included:

- Enclosing combustion turbines to meet 85 dBA at 3 feet
- Enclosure for steam turbine generator
- Silencers on relief valve stacks
- Design major components to limit noise to 90 dBA or 85 dBA at 3 feet
- Locate power block in central portion of site
- Locate cooling towers on north side of site
- Locate brine concentrator compressor inside waste water treatment facility

The applicant has also offered to provide additional sound attenuation at receptors where post-project noise levels would exceed ambient noise levels by 5 dBA, and where residents complain of disturbance from increased noise due to the EAEC. The specific attenuation measures would be case-specific, and could include installation of weather-stripping, acoustically-rated windows and doors, sound insulation in walls and ceilings, attic vent baffles, and provision of mechanical ventilation.

NOISE: Table 5 lists the predicted project noise levels at the nearest receptors in terms of the background noise level (L_{90}). The predicted plant noise level at each location is less than 55 dB CNEL or DNL. The predicted noise levels include the applicant's proposed mitigation measures.

NOISE: Table 5 – Summary of Predicted Operational Noise Levels

Receptor Sites	Nighttime L_{90}, dBA			
	Ambient	Project	Cumulative	Change
1	29 - 40	45	45 - 46	+6 to +16
2	27 - 48	42	42 - 49	+1 to +15
3	30 – 32	43	43	+12 to +13
4	32 - 33	38	39	+6 to +7

Based upon the predicted noise levels at the nearest receptors, Energy Commission staff believes that the operation of the project, as proposed, will result in substantial

increases in background noise levels at the nearest sensitive receptors. The resulting noise levels at Sites 1 and 2 would also exceed the 45 dBA standard of the Alameda County Community Noise Ordinance. The worst-case conditions would typically occur during winter months, when winds may be subdued. During the majority of the year, the increases in nighttime noise levels would be less than in the winter, but would remain substantial.

At Site 3, which represents the school site, the plant noise level is predicted to be 43 dBA. This noise level is within the range of existing daytime noise levels, and is not expected to result in speech or activity interference either inside or outside the school classrooms.

The applicant stated in the AFC that it "does not believe that a noise mitigation package capable of reducing the project's cumulative noise impacts to below 40 dBA L_{90} is achievable" (EAEC 2001a, Response 78, page 43). Energy Commission staff believes that a noise standard of 40 dBA may be achievable.

If the noise emissions of the plant were reduced by an additional 5 dBA, to a maximum of 40 dBA at the nearest receptors, the cumulative noise levels, and the changes in nighttime ambient noise levels, would be reduced to the values shown by **NOISE: Table 6**.

NOISE: Table 6 –Operational Noise Levels with 5 dBA Noise Reduction

Receptor Sites	Nighttime L_{90}, dBA			
	Ambient	Project	Cumulative	Change
1	29 - 40	40	40 - 43	+3 to +11
2	27 - 48	37	37 - 48	+0 to +10
3	30 – 32	40	40 - 41	+9 to +10
4	32 - 33	33	36	+3 to +4

In the above scenario, the worst-case cumulative noise levels would cause increases of up to 11 dBA over ambient noise levels, during periods of low winds. In the majority of the year, when the wind is blowing, the increases would remain substantial at Site 3, but would probably be less than 5 dBA at Sites 1, 2 and 4._This is because background noise levels would be at the high end of the range shown above due to wind noise.

The proposed Condition of Certification **NOISE-6** would require that the noise level produced by the plant operation not exceed 40 dBA L_{eq} at any sensitive receptor. This would ensure that the background noise level (L_{90}) at the most-affected residential receptor would not increase by more than 5 dBA under most weather conditions, and that noise due to the plant operations would not exceed the standards of the Alameda County Community Noise Ordinance at any sensitive receptor. However, the increase in background noise levels resulting from plant operations would exceed 5 dBA at all sites in the quietest part of the year.

To mitigate the effects of the predicted increase in ambient noise levels due to plant operation, Energy Commission staff has proposed Condition of Certification **NOISE-9**, which requires that the project owner provide sound insulation for homes where the

noise from plant operations causes an increase in ambient noise levels greater than 5 dBA, and where the resident has requested the acoustical treatment.

The use of acoustical treatment has been found to be suitable for correcting other noise incompatibilities, such as for traffic and aircraft noise. Its use in this case recognizes that the predicted noise impact will be greatest at nighttime, and in the winter months, when it is most likely that residents will find closed windows and doors to be an acceptable means of achieving the desired acoustical isolation.

Energy Commission staff believes that achieving a noise standard of 40 dBA at the nearest receptor as required by NOISE-6, combined with the noise mitigation measures required by NOISE-9, will ensure that noise impacts will be less than significant.

Tonal and Intermittent Noises

One possible source of annoyance 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 has stated that no strong tonal noises will be generated during the operation of the project.

The applicant has also stated that steam relief vents will be silenced to mitigate the intermittent noise from pressure relief valves. Although these noise sources are expected to be in compliance with the LORS, their noise effects may be significant in the context of the quiet ambient noise environment.

To ensure that no strong tonal noises are present and that intermittent noises are mitigated, Energy Commission staff has proposed a Condition of Certification (**NOISE-6**, below), which requires the applicant to mitigate pure tones and the noise from steam relief valves.

Linear Facilities

The electrical output of the plant will be connected to the existing 230 kV transmission line about 0.5 miles south of the project site (EAEC 2001a, AFC § 8.5.3.8). Noise from the transmission lines will include a corona discharge hum, which is expected to be audible within 100 feet of the power lines. The nearest residences are located more than 100 feet from the transmission lines. The proposed 230 kV switchyard will be located on the project site, and will be at least 0.5 miles from the nearest residence. As a result of the large setbacks of the linear facilities from residences, no noise impacts will occur from linear facilities.

Worker Effects

The applicant recognizes the need to protect plant operating and maintenance personnel from noise hazards, and has committed to comply with applicable LORS (EAEC 2001a, AFC § 8.7). Signs would be posted in areas of the plant with noise levels exceeding 85 dBA (the level that OSHA recognizes as a threat to workers' hearing), and hearing protection would be required. The applicant would implement a comprehensive hearing conservation program. To ensure that construction workers are, in fact, adequately protected, Energy Commission staff has proposed Condition of Certification **NOISE-7**, below.

CUMULATIVE IMPACTS

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.

Pursuant to CEQA, a cumulative impacts analysis can be performed by either 1) summarizing growth projections in an adopted general plan or in a prior certified environmental document, or 2) compiling a list of past, present, and probable future projects producing related or cumulative impacts. The second method has been utilized for the purposes of this Staff Assessment.

The AFC identified no planned projects that could contribute to cumulative noise impacts in the project study area (EAEC 2001a, AFC § 8.4). Two energy-producing facilities (the Tesla Power Project and the Tracy peaker project) are in the general area of the project, but are located at too great a distance to have a measureable effect on project noise levels. Traffic, agricultural and industrial noise sources are present in the vicinity of the project site that could contribute to the cumulative noise levels at sensitive receptors. The effects of noise produced by those sources have been accounted for in part by the ambient noise level measurements, and the resulting noise levels are described in the noise level predictions listed above

Increases in area traffic due to development of the Mountain House project will result in increases in background noise levels in the general area. Traffic noise level increases near the project site will depend primarily upon changes in traffic patterns in the immediate vicinity of the project. In general, it is expected that background noise levels will increase with increasing area development, which will contribute to the project noise levels.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the minority population is less than fifty percent within a six-mile radius of the proposed EAEC (please refer to **Socioeconomics Figure 1** in this Staff Analysis), and Census 1990 information that shows the minority/low income population is less than fifty percent within the same radius. However, there is a pocket of minority persons within six miles that staff has considered for impacts. Based on the noise analysis, staff has identified a potentially significant direct impact resulting from the operation of the project, but with the mitigation proposed in the Conditions of Certification this impact will be reduced to less than significant. Therefore, there is no potential disparate impact on the minority population, and there are no noise environmental justice issues related to this project.

FACILITY CLOSURE

In the future, upon closure of the EAEC, all operational noise from the entire EAEC site would cease, and no further adverse noise impacts from operation of the EAEC would be possible. The remaining potential temporary noise source is 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 of the EAEC, it can be treated similarly. That is, noisy work can 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 unless modified.

RESPONSE TO PUBLIC AND AGENCY COMMENTS

G&DK

Comment G&DK 3: *The commentor noted that, on a visit to the Los Medanos Power Plant, the noise level was not "quiet as a library", as was indicated by the applicant in a public meeting.*

The AFC and this Staff Assessment describe the predicted EAEC noise levels in a quantitative manner. Energy Commission staff notes that the noise produced by the Los Medanos Power Plant is not necessarily representative of the noise expected from the EAEC, as this project will be required to satisfy noise standards that are specific to the power plant configuration, and to its location relative to the nearest receptors. The combination of the recommended exterior noise standard and the acoustical treatment program will ensure that the power plant noise levels inside the most affected homes will be very low, and well within acceptable limits.

Comment G&DK 18: *The commentor noted that noise from other power plants was not "quiet as a library", as was indicated by the applicant in a public meeting.*

See the response above.

CONCLUSIONS AND RECOMMENDATIONS

Energy Commission staff concludes that the EAEC, with the recommended mitigation, will be built and operated to comply with all applicable noise laws, ordinances, regulations, and standards. Energy Commission staff further concludes that if the EAEC facility were designed as described above, and further mitigated as described below in the proposed Conditions of Certification, it is not expected to produce significant adverse noise impacts. To ensure compliance with all applicable noise LORS, Energy Commission staff recommends adoption of the following Conditions of Certification.

PROPOSED CONDITIONS OF CERTIFICATION

NOISE-1 At least 15 days prior to the start of ground disturbance, the project owner shall notify all residents within one mile of the site, 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. 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.

Verification: The project owner shall transmit to the Energy Commission Compliance Project Manager (CPM) in the first Monthly Construction Report following the start of ground disturbance, a statement, signed by the project manager, attesting that the above notification has been performed, and describing the method of that notification. This statement shall also attest that the telephone number has been established and posted at the site.

NOISE-2 Throughout the construction and operation of the project, the project owner shall document, investigate, evaluate, and attempt to resolve all project related noise complaints.

Protocol: The project owner or authorized agent shall:

- Use the Noise Complaint Resolution Form (see Exhibit 1), or functionally equivalent procedure acceptable to the CPM, to document and respond to each noise complaint;
- 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;
- If the noise is project related, take all feasible measures to reduce the noise at its source; 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 30 days of receiving a noise complaint, the project owner shall file a copy of the Noise Complaint Resolution Form, or similar instrument approved by the CPM, with the Alameda County Planning Department, and 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 30-day period, the project owner shall submit an updated Noise Complaint Resolution Form when the mitigation is finally implemented.

NOISE-3 Prior to the start of ground disturbance, the project owner shall submit to the CPM for review a noise control program. 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 above referenced program. The project owner shall make the program available to OSHA upon request.

NOISE-4 If a traditional, high-pressure steam blow process is employed, the project owner shall equip steam blow piping with a temporary silencer that quiets the noise of steam blows to no greater than 55 dBA, measured at any residential receptor. The project owner shall conduct steam blows only on weekdays during the hours of 7 a.m. to 7 p.m., unless the CPM agrees to longer hours based on a demonstration by the project owner that off-site 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 period of execution, to the CPM, who shall review the proposal with the objective of ensuring that the resulting noise levels do not exceed the average nighttime ambient L_{90} value plus 5 dBA. If the low-pressure process is approved by the CPM, the project owner shall implement it in accordance with the requirements of the CPM.

Verification: At least 15 days prior to the first high-pressure steam blow, the project owner shall submit to the CPM and Alameda County drawings or other information describing the temporary steam blow silencer and 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-5 Prior to the first steam blow(s), the project owner shall notify Alameda County and all residents within one mile of the site 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 plant operations.

Verification: Within 5 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.

NOISE-6 The project design and implementation shall include appropriate noise mitigation measures adequate to ensure that the noise level produced by operation of the project will not exceed an hourly average noise level of more than 40 dBA L_{eq} measured at any residence.

No new pure tone components may be introduced. No single piece of equipment shall be allowed to stand out as a source of noise that draws legitimate complaints. Steam relief valves shall be adequately muffled to preclude noise that draws legitimate complaints.

Protocol:

A. Within 30 days of the project first achieving a sustained output of 80 percent or greater of rated capacity, the project owner shall conduct a 25-hour community noise survey at Sites 1 and 2. In addition, the applicant shall conduct short-term survey noise measurements at monitoring sites 3 and 4. The short-term noise measurements shall be conducted during both daytime (7 a.m. to 10 p.m.) and nighttime (10 p.m. to 7 a.m.) periods. The noise surveys shall also include short-term measurement of one-third octave band sound pressure levels at each of the above locations to ensure that no new pure-tone noise components have been introduced.
B. If the results from the two noise surveys (pre-construction vs. operations) indicate that the noise level due to the plant operations exceeds 40 dBA for any given hour during the 25-hour period, mitigation measures shall be implemented to reduce noise to a level of compliance with these limits.
C. If the results from the two noise surveys (pre-construction vs. operations) indicate that pure tones are present, mitigation measures shall be implemented to eliminate the pure tones.

Verification: Within 15 days after completing the post-construction survey, the project owner shall submit a summary report of the survey to the Alameda County Planning Department, and to the CPM. Included in the post-construction survey report will 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. Within 15 days of completion of installation of these measures, the project owner shall submit to the CPM a summary report of a new noise survey, performed as described above and showing compliance with this condition.

NOISE-7 Within 30 days of the project first achieving a sustained output of 80 percent or greater of rated capacity, 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 (Article 105) 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.

NOISE-8 Noisy construction or demolition work shall be restricted to the times of day delineated below:

Weekdays	7 a.m. to 7 p.m.
Weekends and Holidays	8 a.m. to 5 p.m.

Haul trucks and other engine-powered equipment shall be equipped with adequate mufflers. Haul trucks shall be operated in accordance with posted speed limits. Truck engine exhaust brake use shall be limited to emergencies.

Horizontal drill rigs may be operated on a continuous basis, provided that the rigs are fitted with adequate mufflers and engine enclosures, and that the rigs are shielded from view of residences by berms, canal banks or other suitable barriers.

Verification: The project owner shall transmit to the CPM in the first Monthly Construction Report a statement acknowledging that the above restrictions will be observed throughout the construction of the project.

NOISE-9 Where the noise due to project operation, as measured at a nearby sensitive receptor in accordance with **NOISE-6**, exceeds the ambient background noise level by more than 5 dBA, the applicant shall install a sound insulation package at the affected residence, upon written request by the homeowner. The project owner shall notify all affected homeowners of the availability of the sound insulation package.

The sound insulation package shall provide a plant noise level reduction (NLR) of at least 5 dBA in habitable rooms. The acoustical design must ensure that adequate ventilation is provided to habitable rooms in accordance with the Uniform Building Code.

Protocol:

A. At least 15 days prior to the start of construction, the project owner shall notify all residents where the noise due to project operation, as measured at a nearby sensitive receptor in accordance with **NOISE-6**, exceeds the ambient background noise level by more than 5 dBA of the availability of acoustical treatment in accordance with this requirement.

B. Within 60 days of the project owner receiving a request for acoustical treatment from an affected homeowner, the project owner shall prepare an acoustical/architectural analysis to determine the noise mitigation measures which are to be applied at the affected house, based in part upon measurements of the existing noise level reduction of the house. The analysis shall be submitted to the CPM for review and approval.

C. With the consent of the homeowner, the project owner shall select and install the recommended noise mitigation measures within a reasonable time period, to be determined by the CPM in consultation with the homeowner and project owner.

D. After the mitigation measures have been installed, the project owner shall prepare an acoustical analysis demonstrating that the noise level reduction objective of 5 dBA has been achieved. If the objective has not been achieved, additional mitigation measures shall be

implemented as required until it can be demonstrated that the required noise level reduction has been provided.

Verification: The project owner shall transmit to the Energy Commission Compliance Project Manager (CPM) in the first Monthly Construction Report following the start of construction, a statement, signed by the project manager, attesting that the above notification has been performed, and describing the method of that notification. Within 15 days after completing the acoustical analysis, the project owner shall submit a summary report to the CPM. Included in the analysis report will be a description of the mitigation measures necessary to achieve compliance with the 5 dBA plant noise level reduction, and a schedule, subject to CPM approval, for implementing these measures. Within 30 days of completion of installation of the sound mitigation measures, the project owner shall submit to the CPM a summary report of a new analysis, performed as described above and showing compliance with this condition.

EXHIBIT 1 - NOISE COMPLAINT RESOLUTION FORM

East Altamont Energy Center Power Plant Project
(01-AFC-4)

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 plant 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:

Plant Manager's Signature: _____

(Attach additional pages and supporting documentation, as required).

REFERENCES

County of Alameda. 1994. Noise Element of the Alameda County General Plan.

County of Alameda. 1995. East County Area Plan.

County of Alameda. 1988. Chapter 6.60 (Noise) Alameda County General Ordinance Code.

County of Contra Costa. 1996. Noise Element of the Contra Costa County General Plan.

County of San Joaquin. 1999. Section 9-1025.9 (Noise) San Joaquin County Code.

EAEC (East Altamont Energy Center LLC) 2001. Application for Certification, East Altamont Energy Center Project (01-AFC-4). Submitted to the California Energy Commission on March 20, 2001.

EAEC (East Altamont Energy Center LLC) 2001a. Response Set #2 to Energy Commission Data Requests, dated August 17, 2001.

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Federal Transit Administration. 1995. *Transit Noise and Vibration Impact Assessment*. DOT-T-95-16. Harris, Miller, Miller and Hanson, Inc. Burlington, Massachusetts.

State of California. 1990. General Plan Guidelines, Office of Planning and Research, June 1990.

State of California. 1977. Model Community Noise Control Ordinance, Office of Noise Control, April 1977.

NOISE: 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: 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 (Leq), or by average day and night A-weighted sound levels with a nighttime weighting of 10 dBA (Ldn). 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 Ldn 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, they 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 what 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 (USEPA 1971). At 70 dBA, sleep interference effects become considerable.

In order to help the reader understand the concept of noise in decibels (dBA), **NOISE: Table A2** has been provided to illustrate common noises and their associated sound levels, in dBA.

NOISE: 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: California Department of Health Services 1976, 1977.

NOISE: 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: Peterson and Gross 1974

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 (Kryter 1970) can be helpful in understanding the significance of human exposure to noise.

1. Except under special conditions, a change in sound level of one dB cannot be perceived.
2. Outside of the laboratory, a three dB change is considered a barely noticeable difference.
3. A change in level of at least five dB is required before any noticeable change in community response would be expected.
4. A ten dB change is subjectively heard as an approximate doubling in loudness and almost always causes an adverse community response.

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 three dB increase (i.e., the resultant sound level is the sound level from a single passing automobile plus three dB). The rules for decibel addition used in community noise prediction are:

NOISE: 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: Thumann, Table 2.3

SOUND AND DISTANCE

Doubling the distance from a noise source reduces the sound pressure level by six dB.

Increasing the distance from a noise source ten 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:

NOISE: 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: OSHA Regulation

PUBLIC HEALTH

Obed Odoemelam, Ph.D.

INTRODUCTION

Operating the proposed East Altamont Energy Center (EAEC) would produce combustion products and possibly expose the general public and workers to these pollutants as well as the toxic chemicals associated with aspects of operations unrelated to fuel utilization. Such exposures would be considered significant if they occur at levels that can produce specific health symptoms in humans and are the focus of federal and state requirements for specific technological and operational controls. The issue of possible worker exposure is addressed in the **Worker Safety and Fire Protection** section while the health significance of exposure to the project-related electric and magnetic fields (EMF) is addressed in the **Transmission Line Safety and Nuisance** section. Potential impacts from waste generation and disposal are discussed in the **Waste Management** section.

The air pollutants of specific concern for EAEC and similar gas-fired facilities are categorized as criteria pollutants and non-criteria pollutants, which are also known as air toxics or toxic air contaminants (TACs). The criteria pollutants differ from the air toxics in that the former have specific air quality standards, which were established to protect against significant health impacts in humans. The health impacts of criteria pollutants are discussed in the Attachment (A) to this analysis along with the rationale for each applicable standard (as listed in the **Air Quality** section). When a project is proposed for an area with violations of the air quality standards, specific mitigation might be necessary to prevent significant additions to existing levels of the pollutants involved. Since this project is proposed for an air basin in violation of specific air quality standards as noted by the applicant (EAEC 2001a, pages 8.1-5 through 8.1-11, and pages 8.1-68 through 8.1-72), and discussed in the **Air Quality** section, specific mitigation is recommended in that section.

The purpose of this **Public Health** analysis is to assess the emission of EAEC's air toxics for compliance with applicable emission laws, ordinances, regulations, and standards (LORS). If compliance is established, staff would recommend certification as proposed; if not, staff would recommend against certification to protect against the health impacts of specific concern.

LAWS ORDINANCES, REGULATIONS AND STANDARDS (LORS)

The following LORS were established to protect against the impacts of the noted criteria pollutants and the air toxics-related impacts of specific concern in this analysis.

FEDERAL

The Clean Air Act of 1970 (42 U.S.C., section 7401 et seq.)

This section of the act required establishment of the previously noted ambient air quality standards necessary to protect the public against effects in humans and the general

environment. These standards were established by the United States Environmental Protection Agency (EPA) for the major criteria pollutants: nitrogen oxides (NOx), ozone, sulfur dioxide, carbon monoxide, sulfates, lead, and particulate matter with a diameter of 10 micron or less (PM10).

The Clean Air Act of 1970 (42 U.S.C., section 7412)

This section requires new sources, which emit more than 10 tons per year of air toxics or any combination of air toxics, to apply the Maximum Achievable Control Technology (MACT).

STATE

California Health and Safety Code section 39606

This section of the code requires the California Air Resources Board (ARB) to establish California's ambient air quality standards to reflect the California-specific conditions influencing its air quality. Such standards have been established by the ARB for ozone, carbon monoxide, sulfur dioxide, PM10, lead, hydrogen sulfide, vinyl chloride and nitrogen dioxide. The California standards are listed together with the corresponding federal standards in the **Air Quality** section.

California Health and Safety Code section 41700

This section of the code 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 business or property."

California Health and Safety Code section 39650 et seq.

This section of the code mandates that the California Environmental Protection Agency (Cal-EPA) establish safe exposure limits for toxic, non-criteria air pollutants and identify the best available methods for controlling their emission. These laws also require that the new source review rules for each Air District include regulations establishing procedures for controlling the emission of these pollutants. The toxic emissions from natural gas combustion are listed in ARB's Toxic Emissions Factors (CATEF) database for natural gas-fired combustion turbines to allow for uniform assessment as emitted from combustion and non-combustion sources in the state. Cal-EPA has developed specific cancer potency estimates for assessing any cancer risk that these air toxics may pose at specific exposure levels. For toxic air pollutants that do not cause cancer, Cal-EPA established specific no-effects levels (known as reference exposure levels or RELs) for assessing the likelihood of producing health effects at specific exposure levels. Such health effects would be considered significant only when exposure exceeds these reference levels. Staff uses these Cal-EPA potency estimates and reference exposure values in its health risk analyses.

HEALTH AND SAFETY CODE SECTION 44300 ET SEQ.

This section of the code requires facilities, which emit large quantities of criteria pollutants and any amount of non-criteria pollutants to provide the local air district an inventory of toxic

emissions. Operators of such facilities may also be required to prepare a quantitative health risk assessment to address the potential health risks involved. The ARB ensures statewide implementation of these requirements through the state's Air Districts.

LOCAL

Bay Area Air Quality Management District Rule 2-1-316

This rule specifies the procedures necessary to minimize the emission of air toxics from specific sources as required by the Health and Safety Code section 44300. The applicant has complied with the related requirements by conducting a health risk assessment for air toxics emission from EAEC and submitting the results to the Air District.

Bay Area Air Quality Management District Regulation 1, Section 301, "*PUBLIC* NUISANCE" (AMENDED 10/98).

Requirements of this regulation allow for implementation of the emission control measures necessary for compliance with provisions of the Health and Safety Code, section 41700. The applicant, Calpine D. B. A. East Altamont Energy Center LLC (or Calpine) has complied with this requirement by presenting the procedures for minimizing the levels of the air emission at issue.

SETTING

As noted by the applicant, the proposed project site is a 40-acre portion of a 174-acre land parcel located in the far eastern corner of Alameda County. This site is approximately 8 miles northwest of the City of Tracy, 12 miles east of Livermore, 5 miles south of Byron, and less than 1 mile from the San Joaquin County border (EAEC 2001a, pages 8.6-1 and 12-1). This area of rural Alameda County is sparsely populated, as it is zoned for agriculture, electric utility corridors (such as substations, transmission lines, and wind farms), highways, recreation uses, and water management projects, with the actual project site currently used for agriculture.

The information from the applicant (EAEC 2001a, pages 8.4-8, 8.12-1) shows that there is only one institution with sensitive receptors within a 3-mile radius of the project site. Staff has verified the accuracy of this information. Sensitive individuals include children, the elderly, and individuals with respiratory diseases. They may be found in relatively small numbers in individual residences or in relatively large numbers in specific establishments such as schools, hospitals, daycare centers, and convalescent homes. The sensitive receptor location in this case is an elementary school (Mountain House School) located about 1 mile from the site. When there are many sensitive receptor locations in a project area, the probability of health complaints would increase during project operations. It is for this that establishments with relatively large numbers of sensitive receptors are identified for special assessment in considering the location for a project. Staff holds all projects to the same health standards whether proposed for a major population center or a sparsely populated area.

The health effects of the air toxics of specific concern in this analysis are assessed separately by staff according to their potential to induce cancer or effects other than

cancer. Staff would not recommend certification if any potential health impacts were determined to be significant as discussed below.

METHOD FOR ASSESSING THE CANCER AND NON-CANCER IMPACTS OF TOXIC AIR POLLUTANTS

Any air toxics-related health risks from operating the proposed EAEC and similar projects would mainly be associated with emissions from natural gas-fired combustion turbines, auxiliary burners, cooling towers, and auxiliary equipment such as diesel-fueled emergency generators and fire pumps. For the surrounding population, the risk of cancer or non-cancer effects is assessed from exposure estimates obtained from dispersion modeling. According to present knowledge, cancer begins with specific impacts at the genetic level, suggesting a specific (if theoretical) risk from every exposure to a carcinogen. The aim of present regulations is to eliminate all such exposures to the extent feasible for the source in question. This non-threshold concept is recognized as sharply contrasting with assumptions about non-cancer effects, which are assumed to result only from exposure above specific levels, meaning that significant health impacts would be prevented by maintaining exposures below the applicable exposure standards.

The procedure used for assessing such cancer and non-cancer impacts is known as a health risk assessment, which consists of the following steps:

- A hazard identification step in which each pollutant of concern is identified along with possible health effects;
- A dose-response assessment step in which the relationship between the magnitude of exposure and the probability of effects is established;
- An exposure assessment step in which the possible extent of pollutant exposures from a project is established for all possible pathways by dispersion modeling; and
- A risk characterization step in which the nature and the magnitude of the possible human health risk is assessed.

Health Effects Assessed

The types of air toxics-related health impacts that are considered in this analysis are those that could result shortly after exposure or following long-term (or chronic) exposure. Those from short-term exposure are known as acute effects and generally result from exposure at relatively high levels. Some examples of air toxics-induced non-cancer health effects include headaches, dizziness, coughing, nausea, asthma, rash, and irritation of any part of the body such as the eyes, throat and skin.

For EAEC and other modern gas-fired facilities, high-level toxic exposures (at levels capable of acute effects) could occur only during major accidents, not during routine operations when emissions are much lower. Since acute health impacts are not commonly associated with routine operation of such facilities, effects from chronic exposures are considered of greater concern than acute effects in assessing the potential for significant human health impacts (although staff still addresses the potential for significant acute impacts). Compliance with Air District-mandated emission control technologies is

reflected by the incremental cancer and non-cancer risk estimates calculated. Since these incremental risk estimates are calculated the same way for gas-fired power plants, they can be used, despite underlying scientific uncertainties, to compare similar projects for compliance with the best emission control technologies as currently identified for statewide use by the ARB.

Estimating The Risk Of Non-Cancer Effects

The method used by regulatory agencies to quantify the likelihood of acute or chronic impacts of air toxics is the hazard index method. In the current assessment approach, a hazard index is calculated as a numerical representation of the likelihood of significant health impacts at the exposure levels expected for the source being considered. This index is calculated by dividing the exposure estimate by the applicable reference exposure level (REL). After calculating the hazard indices for the individual pollutants, these indices are added together for all those that affect the same part of the body or target organ, to obtain a total hazard index for the source. Total hazard indices of 1.0 or less are regarded as indicating an insignificant addition to the non-cancer effects being considered. An index of more than 1.0 would reflect a potential for significant impacts.

Estimating The Risk Of Cancer

Since cancer is currently considered inducible from every exposure to a carcinogen, staff and other regulatory agencies generally consider the risk of cancer induction and manifestation as more sensitive than the risk of non-cancer effects for assessing the environmental acceptability of the long-term presence of sources of both carcinogens and non-carcinogens. The risk of such induction and manifestation is assumed to increase with exposure duration, meaning for example, that the risk from life time exposure would be higher than the risk from short-term exposure. This sensitivity difference accounts for the prominence of theoretical cancer risk estimates in the environmental risk assessment process.

For any source of specific concern, the risk of operations-related cancer is obtained by multiplying the exposure estimate by the potency factors for the individual carcinogens to be emitted. These potency factors are numerical values conservatively established to represent the cancer-causing potential of one carcinogen as compared to the others. After calculating these individual risk values, they are added together to obtain the total incremental cancer risk estimate from operating the project over a period conservatively assumed to span the 70-year lifetime of the average individual. Given the conservatism of both the exposure duration and the other phases of this risk calculation process, these numerical estimates are regarded as only representing the upper bounds on the project-related cancer risk at issue. The actual risk will likely be lower and could indeed be zero. The significance of these estimates as indicators of a real cancer hazard is assessed according to specific evaluative criteria as discussed below.

STAFF'S SIGNIFICANCE CRITERIA

Various state and federal agencies specify different cancer risk levels as levels of significance. For example, a risk of 10 in a million is mostly considered significant under the Air Toxics "Hot Spots" (AB 2588) and the Proposition 65 programs and, therefore,

used as a threshold for public notification in cases of air toxics emissions from existing sources.

In the current regulatory practice, most health risk assessments are conducted in two phases. In the first phase (which is the screening phase), risk calculations are made using conservative, simplifying assumptions, which tend to overestimate rather than underestimate the risk. If the estimate from this screening-level analysis were below 10 in a million, staff would regard the suggested cancer risk as insignificant and not warranting further analysis for specific action. If the estimate were more than 10 in a million, a more refined analysis (using more situation-specific assumptions) might be necessary to assess the need for mitigation. In such a refined analysis, staff would recommend specific mitigation only when the risk estimate is 10 in a million or more. This limit-based regulatory approach is intended to reduce the rate of addition to the high (1 in 4, or 250,000 in a million) background cancer risk of the average individual. While the causes of some types of cancers are well known, the causes of most of human cancers remain largely unknown. What has become increasingly clear to scientists, however, is that environmental pollutants are responsible for only a small fraction of human cancers in general. The South Coast Air Quality Management District (SCAQMD 2000, page 2) noted this fraction, in their publication, as only about two percent of cancer cases.

For non-carcinogenic pollutants, staff considers significant health impacts to be unlikely when the total hazard index is 1.0 or less. If more than 1.0, staff would regard the related emissions as potentially significant from an environmental health perspective but would recommend specific mitigation only after considering the uncertainties in the assessment process.

IMPACTS

POTENTIAL IMPACTS OF PROJECT'S NON-CRITERIA POLLUTANTS

The health impacts of EAEC's air toxics of specific concern in this analysis can be assessed separately as construction-phase impacts and operational-phase impacts.

Construction Phase Impacts

Possible construction-phase health impacts, as noted by the applicant (EAEC 2001a, Appendix 8.1E), are those from human exposure to (a) the windblown dust from site excavation, and grading, and (b) emissions from construction-related equipment. The dust-related impacts may derive from exposure to the dust itself as PM10, or exposure to the toxic contaminants adsorbed on to it. Specific conditions of certification are proposed in the **Waste Management** section to prevent worker or public exposure to soil-bound contaminants. If these conditions are implemented, the only construction-related PM10 impacts of potential significance would derive from possible PM10 impacts as a criteria pollutant. The potential for significant impacts is assessed in the **Air Quality** section.

Another construction emission problem of possible health significance is the diesel exhaust from use of diesel-fueled equipment. Since diesel exhaust has been established as a potent human carcinogen, construction-related emission levels should be regarded as

possibly adding to the carcinogenic risk of specific concern in this analysis. The maximum cancer risk from the use of diesel-fueled equipment for EAEC's construction was conservatively calculated by the applicant (EAEC 2001q) to be 11 in a million for the maximally exposed individual located near the project property line. As noted by the applicant, this screening-level calculation was made without adjusting for the ARB-noted PM10 reduction from use of low-sulfur fuel as proposed for the project. Adjusting for such reduction would yield a maximum risk of 8.25 in a million, which would be much lower at the nearest residences in this sparsely populated area. Such a screening-level risk estimate is not considered by staff as warranting more mitigation than specified in the applicant's Construction Mitigation Plan (EAEC 2001a, Appendix 8.1E). The implementing condition of certification is specified as **AQC-2** in the **Air Quality** section. Staff considers these conditions as adequate for the cancer and non-cancer risk prevention intended by the ARB.

Operational Impacts

As noted in a publication by the South Coast AQMD (SCAQMD 2000, page 6), one property that distinguishes the air toxics of concern in this analysis from the criteria pollutants is that their impacts tend to be highest in close proximity to their sources and quickly drop off with distance from them. This means that the levels of EAEC's air toxics would be highest in the immediate area and decrease rapidly with distance away from locations of maximum impact. One main focus of this analysis is to establish whether or not such exposures would be at levels of possible health significance as established using existing assessment methods.

The applicant's estimates of the EAEC's potential contribution to the area's carcinogenic and non-carcinogenic pollutants were obtained from a screening-level health risk assessment conducted according to procedures specified in the 1993 California Air Pollution Control Officer's Association (CAPCOA) guidelines. The results from this assessment were provided to staff along with documentation of the assumptions used (EAEC 2001a, pages 8.1-42 through 8.1-44, and pages 8.6-4 through 8.6-8). Such documentation was provided with respect to the following:

- Pollutants considered;
- Emission levels assumed for the pollutants involved;
- Dispersion modeling used to estimate potential exposure levels;
- Exposure pathways considered;
- The cancer risk estimation process;
- Hazard index calculation; and
- Characterization of project-related risk estimates.

Staff has found these assumptions to be acceptable and has validated the applicant's findings with regard to the numerical public health risk estimates expressed either in terms of the hazard index for each non-carcinogenic pollutant, or a cancer risk for estimated levels of the carcinogenic pollutants. These analyses were conducted to establish the maximum potential for acute and chronic effects on body systems such as the liver, central

nervous system, the immune system, kidneys, the reproductive system, the skin and the respiratory system.

The following noncriteria pollutants were considered in this screening-level analysis with respect to non-cancer effects from the inhalation: ammonia from the use of the selective catalytic reduction (SCR) system for NOx control, acetaldehyde, acrolein, arsenic, benzene, 1,3 butadiene; chromium, copper, ethylbenzene, formaldehyde, hexane, lead, mercury, naphthalene, nickel, polycyclic aromatic hydrocarbons (PAHs), propylene oxide, silver, toluene, xylene, and zinc. The following were considered with regard to a possible cancer risk: acetaldehyde, arsenic, benzene, 1, 3 butadiene, cadmium, chromium, formaldehyde, PAHs and propylene oxide.

A maximum chronic hazard index of 0.086 was calculated for the maximally exposed individual, with an index of 0.14 similarly calculated for acute effects. These values are well below staff's significance criteria, suggesting that these pollutants are unlikely to pose a significant risk of chronic or acute effects anywhere in the project area.

The highest cancer risk was calculated as 0.96 in one million for all the project-related sources (gas turbines, auxiliary boiler, cooling tower, emergency generator, and fire engine). This maximum risk was calculated for a point away from the property line where the maximum risk of the project's emergency pump was calculated as 0.9 in a million. This emergency pump-related risk would decrease further away from the property lines towards the point of maximum impact for all the project's carcinogens. It was for this maximum impact point that the risk of 0.96 in a million was calculated.

The relative contributions of the project's sources of the considered carcinogens are listed below:

Project Source	**POTENTIAL CONTRIBUTION TO TOTAL RISK**
Gas turbines	0.00035 in a million
Auxiliary boiler	0.0475 in a million
Cooling tower	0.0000286 in a million
Emergency generator	0.0.0149 in a million
Fire pump engine	0.895 in a million
Total Cancer Risk	0.96 in a million

The conservatism in the employed risk calculation method is reflected by the fact that (a) the individual considered is conservatively assumed to be exposed at the highest possible levels to all the carcinogenic pollutants from the project for a 70-year lifetime, (b) all the carcinogens are assumed to be equally potent in humans and experimental animals, even when their cancer-inducing abilities have not been established in humans, and (c) humans are assumed to be as susceptible as the most sensitive experimental animal despite knowledge that such cancer potencies often differ between humans and experimental animals. Cancer-causing ability has been established in humans for only a relatively few of

the many environmental chemicals identified so far as capable of cancer induction in experimental animals.

CUMULATIVE IMPACTS OF AREA AIR TOXICS

When toxic pollutants are emitted from multiple sources within a given area, the cumulative, or additive, impacts of such emissions could, in concept, lead to significant health impacts within the population, even when such pollutants are emitted at insignificant levels from the individual sources involved. Analyses of such emissions have shown, however, that the peak impacts of such toxic pollutants are normally localized within relatively short distances from the source. Given the low cancer and non-cancer risks from all of EAEC's toxic emissions, staff has determined that the project will not contribute significantly to any area toxic exposure of a cumulative nature. The cumulative impacts of operational-phase criteria pollutants were assessed in the **Air Quality** section in establishing the potential extent of the needed emission offsets.

ENVIRONMENTAL JUSTICE

As noted in the **Socioeconomics** section, there are a few pockets of predominantly minority populations in the impact area of the proposed EAEC. The presence of such predominantly minority populations points to the possibility of environmental injustice in human exposures to the project's air pollutants. Since (a) environmental injustice is encountered in cases of pollutant emissions at levels of potential health significance and (b) the health risk from the project's operations were established as potentially insignificant, staff does not consider the environmental justice as a significant issue for the toxic air pollutants of primary concern in this analysis.

FACILITY CLOSURE

As noted in the introduction section, the toxic pollutants of primary concern in this analysis are those from routine operation of the proposed project. During temporary or permanent closure, the main concern would be over the non-routine releases of hazardous materials or wastes on site. Such releases are discussed respectively in the **Hazardous Materials** and **Waste Management** sections. Since project operations would be stopped during forced temporary closures, any hazardous releases would not be in significant amounts. During permanent closure, the only emissions of potential significance would derive from demolition or dismantling activities and the equipment used. Such emissions would be subject to controls according to requirements in conditions adopted by the Energy Commission after a closure plan is received from the project owner.

CONCLUSIONS AND RECOMMENDATIONS

Staff has determined that the toxic air emissions from the construction and operation of the proposed natural gas-burning EAEC and its auxiliary equipment are at levels not requiring mitigation beyond the levels proposed. The conditions for ensuring compliance with all applicable air quality standards are specified in the **Air Quality** section for the area's problem criteria pollutants.

Since the project-related cancer and non-cancer risks would be at levels reflecting controls with technology established by the ARB as most effective for this and similar facilities and related equipment, staff does not recommend additional mitigation with respect to the operations-related air toxics considered. The potential impacts from construction-related toxic exposures should be minimized through compliance with related conditions in the **Air Quality**, and **Waste Management** sections. Since these conditions are intended as protection against health impacts, additional conditions of certification are considered unnecessary in this **Public Health** section.

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EAEC (East Altamont Energy Center) 2001q. Applicant's response to informal comments submitted by ARB, docketed August 28, 2001.

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ATTACHMENT A - CRITERIA POLLUTANTS

OZONE (O_3)

Ozone is not directly emitted from specific sources but is formed when reactive organic compounds (VOCs) interact with nitrogen oxides in the presence of sunlight. Heat speeds up the reaction, typically leading to higher concentrations in the relatively hot summer months. Ozone is a colorless, reactive gas with oxidative properties that allow for tissue damage in the exposed individual. The effects of such damage could be experienced as respiratory irritation that could interfere with normal respiratory function. Ozone can also damage plants and other materials susceptible to oxidative damage.

The U.S. EPA revised its federal ozone standard on July 18, 1997 (62 Fed. Reg. 38856), based on health studies that had became available since the standard was last revised in 1979. These new studies showed that adverse health effects could occur at ambient concentrations much lower than reflected in the previous standard, which was based on acute health effects experienced during heavy exercise. In proposing the new standard, the EPA identified specific health effects known to have been caused by short-term exposures (of one to three hours) and prolonged exposure (of six to eight hours) (61 Fed. Reg. 65719). However, a 1999 federal court ruling blocked implementation of the ozone 8-hour standard, which is yet to be implemented.

Acute health effects from short-term exposures include a transient reduction in pulmonary function, and transient respiratory symptoms including cough, throat irritation, chest pain, nausea, and shortness of breath with associated effects on exercise performance. Other health effects of short-term or prolonged O_3 exposures include increased airway responsiveness (which predisposes the individual to bronchoconstriction induced by external stimuli such as pollen and dust), susceptibility to respiratory infection (through impairment of lung defense mechanisms), increased hospital admissions and emergency room visits, and transient pulmonary inflammation.

Generally, groups considered especially sensitive to the effects of air pollution include persons with existing respiratory diseases, children, pregnant women, and the elderly. However, controlled exposure data on people in clinical settings have indicated that the population at greatest risk of acute effects from ozone exposures as children and adults engaged in physical exercise. Children are most at risk because they are active outside, playing and exercising, during summer when ozone levels are highest. Adults who are outdoors and engaging in heavy exertion in the summer months are also among the individuals most at risk. This happens because such exertion increases the amount of O_3 entering the airways and can cause O_3 to penetrate to peripheral regions of the lung where lung tissue is more likely to be damaged. These individuals, as well as those with respiratory illnesses, such as asthma, can experience a reduction in lung function and increased respiratory symptoms, such as chest pain and cough, when exposed to relatively low ozone levels during periods of moderate exertion.

CARBON MONOXIDE (CO)

Carbon monoxide is a colorless, odorless gas, which is a product of inefficient combustion. It does not persist in the atmosphere, being quickly converted to carbon dioxide. However, it can reach high levels in localized areas, or "hot spots".

CO reduces the oxygen carrying capacity of the blood, thereby disrupting the delivery of oxygen to the body's organs and tissues. Persons sensitive to the effects of carbon monoxide include those whose oxygen supply or delivery is already compromised. Thus, groups potentially at risk to carbon monoxide exposure include persons with coronary artery disease, congestive heart failure, obstructive lung disease, vascular disease, and anemia, the elderly, newborn infants, and fetuses (CARB 1989, p. 9). In particular, people with coronary artery disease were found to be especially at risk from carbon monoxide exposure (CARB 1989, p. 9). Tests conducted on patients with confirmed coronary artery disease indicated that exposure to low levels of carbon monoxide during exercise can produce significant cardiac effects. These effects include chest pain (angina) and electrocardiographic changes indicative of effects on the heart muscle (CARB 1989, p. 6). Such changes can limit the ability of patients with coronary artery disease to exert themselves even moderately. Therefore, the statewide carbon monoxide one-hour and eight-hour standards were adopted in part to prevent aggravation of chest pain. Additionally, however, the standards are intended to prevent decreased exercise tolerance in persons with peripheral vascular disease and lung disease, impaired central nervous system functions, and effects on the fetus (Cal. Code Regs. Tit. 17, 70200).

PARTICULATE MATTER (PM)

Particulate matter is a generic term for particles of various substances, which occur as either liquid droplets or small solids of a wide range of sizes. Particles with the most potential to adversely affect human health are those less than 10 micrometers (millionths of a meter) in diameter (or PM10), which may be inhaled and deposited within the deep portions of the lung (PM10). PM may originate from anthropogenic or natural sources such as stationary or mobile combustion sources or windblown dust. Particles may be emitted directly to the atmosphere or result from the physical and chemical transformation of gaseous emissions such as sulfur oxides, nitrogen oxides, and volatile organic compounds. PM10 may be made up of elements such as carbon, lead, and nickel; compounds such as nitrates, organics, and sulfates; and complex mixtures such as diesel exhaust and soil fragments. The size, chemical composition, and concentration of ambient PM10 can vary considerably from area to area and from season to season within the same area.

PM10 can be grouped into two general sizes of particles, fine and coarse, which differ in formation mechanisms, chemical composition, sources, and potential health effects. Fine-mode particles are those with a diameter of 2.5 micrometers or less (PM2.5), while the coarse-mode fraction of PM consists of particles ranging from 10 micrometers down to 2.5 micrometers in diameter. A 1999 federal court ruling blocked implementation of these standards, which is yet to be implemented.

PM2.5 is derived both from combustion by-products, which have volatilized and condensed to form primary PM2.5 and from precursor gases reacting in the atmosphere to form secondary PM2.5. Components include nitrates, organic compounds, sulfates, ammonium

compounds, and trace elements (including metals) as well as elemental carbon such as soot. Major sources of PM2.5 are fossil fuel combustion by electric utilities, industry and motor vehicles, vegetation burning, and the smelting or other processing of metals. Dry deposition of fine mode particles is slow allowing such particles to often exist for long periods of time (of from days to weeks) in the atmosphere and travel hundreds to thousands of kilometers. They tend to be uniformly distributed over urban areas and larger regions and are removed from the atmosphere primarily by forming cloud droplets and falling out within raindrops.

Coarse-mode PM10 is formed by crushing, grinding, and abrasion of surfaces, and in the course of reducing large pieces of materials to smaller pieces. Coarse particles consist mainly of soil dust containing oxides of silicon, aluminum, calcium, and iron; as well as fly ash, particles from tires, pollen, spores, and plant and insect fragments. Coarse particles normally have shorter lifetimes (minutes to hours) and only travel over short distances (of less than tens of kilometers). They tend to be unevenly distributed across urban areas and have more localized effects than the finer particles.

The health effects of PM10 from any given source usually depend on the toxicity of its constituent pollutants. The size of the inhaled material usually determines where in the respiratory it is deposited. Coarse particles are deposited most readily in the nose and throat area while the finer particles are more likely to be deposited within the bronchial tubes and air sacs, with the greatest percentage deposited in the air sacs. Particles deposited in the air sacs are removed more slowly by the body's particulate defense system than those deposited in the nose and throat area. Deposition in the air sacs allows for the longer residence time necessary for impacts of potential health significance.

Many epidemiological studies have shown exposure to particulate matter as capable of a variety of health effects, including premature death, aggravation of respiratory and cardiovascular disease, changes in lung function and increases in existing respiratory symptoms, effects on lung tissue structure, and impacts on the body's respiratory defense mechanisms. The underlying biological mechanisms are still poorly understood. Based on their review of a number of these epidemiological studies (as published after 1987 when the federal standards were last revised), together with suggestion of PM2.5 concentrations as a more reliable surrogate for the health impacts of the finer fraction of PM than PM10, EPA concluded that the then-current standards were not sufficiently stringent to protect against significant effects in exposed humans. Therefore, federal PM standards were revised on July 18, 1997 (62 Fed. Reg. 38652) to add new, annual and 24-hour PM2.5 standards to the existing annual and 24-hour PM10 standards. Taken together, these new standards were meant to provide additional protection against a wide range of PM-related health effects, including premature death, increased hospital admissions and emergency room visits, primarily among sensitive individuals such as the elderly, children and individuals with cardiopulmonary diseases such as asthma. Other impacts include decreased lung function (particularly in children and asthmatics), and alterations in lung tissue and structure.

California has 24-hour and annual standards for only PM10 are based on symptoms observed at the lowest concentrations used in human studies (CARB 1982, pp. 81,84).

These studies were aimed at establishing the PM10 levels capable of inducing asthma, premature death and bronchitis-related symptoms. They were set to protect against such impacts in the general population as well as sensitive individuals such as patients with respiratory disease, declines in pulmonary function, especially as related to children (Cal. Code Regs. Tit. 17, 70200). These standard was set to be more stringent than the federal standard, which the ARB regards as inadequate for the protection desired (CARB 1991, p. 26).

The annual standard is based on studies showing long-term exposure to PM10 as capable of decreasing breathing capability and increasing respiratory illnesses among susceptible individuals, especially children (CARB 1991, p. 25). The annual standard is also set to also accommodate the need for protection against any carcinogenic effects of PM10 (CARB 1982, p. 84).

NITROGEN DIOXIDE (NO_2)

Nitrogen dioxide is formed either directly or indirectly when oxygen and nitrogen in the air combine together during the combustion. It is a relatively insoluble gas, which can penetrate deep into the lungs, its principal site of toxicity. Its toxicity is thought to be due to its capacity to initiate free radical-mediated reactions while oxidizing cellular proteins and other biomolecules (CARB 1992, Appendix A, p. 4).

Sub lethal exposures in animals usually produce inflammations and varying degrees of tissue injury characteristic of oxidant damage (Evans in CARB 1992, Appendix A, and p 5). The changes produced by low-level acute or sub chronic exposures appear to be reversible when the animal study subject is allowed to recover in clean air.

Health effects of particular concern in relation to low-level nitrogen dioxide exposure include: (1) effects of acute exposure on some asthmatics and possibly on some persons with chronic bronchitis, (2) effects on respiratory tract defenses against infection, (3) effects on the immune system, (4) initiation or facilitation of the development of chronic lung disease, and (5) interaction with other pollutants (CARB 1992, Appendix A, p. 5).

Several groups, which may be especially susceptible to nitrogen dioxide-related health effects have been identified from human studies (CARB 1992, Appendix A, and p. 3). These include asthmatics, persons with chronic bronchitis, infants and young children, cystic fibrosis and cancer patients, people with immune deficiencies, and the elderly.

Studies involving brief, controlled exposures on sensitive individuals have shown an increase in bronchial reactivity or airway responsiveness of some asthmatics, as well as decreased lung function in some patients with chronic obstructive lung disease (CARB 1992, Appendix A, p. 2). In general, bronchial hyper reactivity (an increased tendency of the airways to constrict) is markedly greater in asthmatics than in non-asthmatics upon exposure to initiating respiratory irritants (CARB 1992a, p. 107). At exposure concentrations of specific relevance to the current one-hour ambient standard, there appears to be little, if any, effect on respiratory symptoms of asthmatics (CARB 1992a, p. 108).

SULFUR DIOXIDE (SO_2

Sulfur dioxide is formed when any sulfur-containing fuel is burned. SO_2 is highly soluble and consequently absorbed in the moist passages of the upper respiratory system. Exposure to sulfur dioxide can lead to changes in lung cell structure and function that adversely affect a major lung defense mechanism known as muco-ciliary transport. This mechanism functions by trapping particles in mucus in the lung and sweeping them out via the cilia (fine hair-like structures) also in the lung. Slowed mucociliary transport is frequently associated with chronic bronchitis.

Exposure to sulfur dioxide can produce both short- and long-term health effects. Therefore, California has established sulfur dioxide standards to reflect both short- and long-term exposure concerns. Based on controlled exposure studies of human volunteers, investigators have found that asthmatics comprise the group most susceptible to adverse health effects from exposure to sulfur dioxide (CARB 1994, p. V-1).

The primary short-term effect is bronchoconstriction, a narrowing of the airways, which results in labored breathing, wheezing, and coughing. The short-term (one-hour) standard is based on bronchoconstriction and associated symptoms (such as wheezing and shortness of breath) in asthmatics and is designed to protect against adverse effects from five to ten minute exposures. In the opinion of the California Office of Environmental Health Hazard Assessment, the short-term ambient standard is likely to afford adequate protection to asthmatics engaged in short periods of vigorous activity (CARB 1994, Appendix A, p. 16).

Longer-term exposure is associated with increased incidence of respiratory symptoms (such as coughing and wheezing) or respiratory disease, decreases in pulmonary function, and an increased risk of premature mortality (CARB 1991a, p. 12). The long-term (24-hour) standard is based upon increased incidence of respiratory disease and premature mortality. The standard includes a margin of safety based on epidemiological studies, which have shown adverse respiratory effects at levels slightly above the standard. Some of the studies indicate a sulfur dioxide threshold for effects, suggesting that no significant effects are expected from exposures to concentrations at the state standard (Ibid.).

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SOCIOECONOMICS

James Adams

INTRODUCTION

The technical area of Socioeconomics includes several related areas of interest and concern. A typical socioeconomic impact analysis evaluates the effects of short-term and long-term project-related population changes on local schools, medical and protective services, as well as the fiscal and physical capability of local governmental agencies to meet the needs of project-related changes in population. This analysis discusses the potential direct and cumulative impacts of the proposed East Altamont Energy Center (EAEC) on local communities, community resources, and public services. The socioeconomic analysis also includes consideration of demographics and its relationship to Environmental Justice.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

FEDERAL

Executive Order 12898

"Federal Actions to address Environmental Justice (EJ) in Minority Populations and Low-Income Populations," focuses federal attention on the environment and human health conditions of minority communities and calls on federal agencies to achieve environmental justice as part of this mission. The order requires the U.S. Environmental Protection Agency (USEPA) and all other federal agencies (as well as state agencies receiving federal funds) to develop strategies to address this issue. The agencies are required to identify and address any disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority and/or low-income populations.

Civil Rights Act of 1964, Public Law 88-352, 78 Stat.241

(Codified as amended in scattered sections of 42 U.S.C.) Title VI of the Civil Rights Act prohibits discrimination on the basis of race, color, or national origin in all programs or activities receiving federal financial assistance.

STATE

Title 14 California Code of Regulations, section 15131-CEQA Guidelines

> Economic or social effects of a project shall not be treated as significant effects on the environment, however, economic or social factors of a project may be used to determine the significance of physical changes caused by the project. In addition, economic, social and particularly housing factors shall be considered by public agencies together with technological and environmental factors in deciding whether changes in a project are feasible to reduce and or avoid the significant effects on the environment.

California Government Code, Sections 65995-65997

SB 50 and other statutory amendments enacted in 1998 provide that, notwithstanding any other provisions of local or state law (including CEQA), state and local agencies may not require mitigation for the development of real property for effects on school enrollment except as provided by Government Code Section 65996(a). The relevant provisions restrict fees for the development of commercial and industrial space to approximately $0.31 per square foot of "chargeable covered and enclosed space." (Govt. Code 5995(b)(2))

LOCAL

East Alameda County Area Plan- Economic Development and Utilities

Policy 50: The County shall encourage a diversity of job producing industries that reflect the skills of the local labor force to locate in the East County area.

Policy 262 The County shall facilitate the provision of adequate gas and electric service and facilities to serve existing and future needs while minimizing noise, electromagnetic, and visual impacts on existing and future residents.

SETTING

The proposed project is located in the northeast corner of Alameda County approximately eight miles northwest of the City of Tracy. The site is within one mile of Contra Costa and San Joaquin Counties, and therefore staff considers the study area to be these three counties (Tri-County). More specifically, the proposed site is located on the east side of Mountain House road just south of Byron Bethany Road and north of Kelso Road. For a more complete description of the location, please refer to the **Project Description** section of this document and the site arrangement layout section of the Application for Certification (EAEC 2001a, AFC, page 2-2).

DEMOGRAPHIC CHARACTERISTICS

The Tri-County area had a population of 2.9 million people in 2000. The estimate for 2005 is 3.2 million. Of the year 2000 total, an estimated 1.4 million live in Alameda County, a 14 percent increase from 1990. Alameda County population growth is expected to continue, with projections of 1.5 million people in 2010 and 1.7 million by 2015 (EAEC 2001a, AFC, Table 8.8-1, page 8.8-2). The nearest city, Tracy, has a population of 61,000 (City of Tracy, 2001a).

Population characteristics of the census blocks within a six-mile radius are shown in **Socioeconomics Figure 1**. **Figure 1** shows the percentage of minority residents by census block based on 2000 Census results within six miles. Approximately 12 blocks had a minority population of 25 to 50 percent, 8 blocks had a minority population of 50 to 75 percent, and 7 blocks had a minority population greater than 75 percent. The actual number of individuals in these blocks is small and is also displayed in **Figure 1**. The minority population within the six mile radius is 34 percent. On the basis of several

visits, staff has concluded that the project area is predominately agricultural land with houses or small ranches scattered throughout.
In 1990, the last year that the U.S. Census Bureau released the relevant data, the percentage of the population living below the poverty level was 10 percent within a six-mile radius of the EAEC, 11 percent in Alameda County, 7 percent in Contra Costa County, and 16 percent in San Joaquin County. The average income for the Tri-County area in 1989 was $45,037 for Alameda, $51,651 for Contra Costa, and $40,314 for San Joaquin (EDD 2001).

EMPLOYMENT CHARACTERISTICS

In August 2001, the Tri-County area had a total of 1.3 million wage and salary jobs. The unemployment rate was approximately 5.6 percent in 1999. **Socioeconomics Table 1** shows the distribution of employment by industrial sector for Alameda, Contra Costa and San Joaquin Counties.

Services is the largest industry in Alameda County, which accounts for 28.5 percent of the jobs, followed by government at 18.7 percent, retail trade at 14.8 percent, and manufacturing at 14.7 percent. The corresponding numbers for San Joaquin County are services at 22.7 percent, government at 18 percent, retail trade at 16.4 percent, and manufacturing at 12 percent. Contra Costa County has an even greater amount of service jobs which amount to nearly 33 percent of the total. This is followed by retail trade at 18.8 percent, government at 14.2 percent, and manufacturing at 8.3 percent (DOF 2001).

HOUSING

The estimated size of the Alameda County housing stock was 536,495 units on January 1, 2000 (DOF 2001). There were 353,983 houses in Contra Costa County and 190,003 in San Joaquin County. The vacancy rates for all three counties were approximately 5 percent. Within the three counties, there are currently about 14,000 temporary housing units such as hotels and motels (DOF 2001).

SCHOOLS

The closest school to the site is the Mountain House Elementary School, located on Mountain House Road just south of Kelso Road approximately one-half mile from the EAEC site. There is also a high school in the City of Tracy approximately eight miles south east of the site. Because there is a sufficient labor pool of construction workers within the study area and workers are not expected to relocate their families, data on school capacity were not compiled.

UTILITIES, EMERGENCY, AND OTHER SERVICES

Pacific Gas and Electric Company (PG&E) provides natural gas and electric power to the project site. The Byron Bethany Irrigation District will supply water to the site, and the Applicant will construct a septic system and leachfield or use a holding tank and transport wastewater offsite. Local telephone service is provided by Pacific Bell (EAEC, AFC, page 8.8-13).

Fire protection and emergency medical response to the site is discussed in the **Worker Safety and Fire Protection** section of this PSA. There are twelve hospitals within Alameda County including Eden Medical Center in Castro Valley, which is the regional trauma center for Southern Alameda County (EAEC 2001a, AFC, page 8.8-12). The Alameda County Sheriff's Office provides two patrolmen to the Mountain House/East Altamont area and the California Highway Patrol provides law enforcement services for state highways and roads. In addition, the City of Tracy has a police department that has a mutual aid agreement with the Sheriff's Office to provide assistance if needed (Tracy Police Department 2001b).

SOCIOECONOMICS TABLE 1
Employment by Industry: 1999-2000

Sector	Alameda & Contra Costa Counties	San Joaquin County
Agriculture/mining	7,200	18,400
Construction	70,000	13,400
Manufacturing	124,700	25,000
Transportation	65,100	14,800
Trade	239,000	44,900
Finance/Insurance Real Estate	107,100	8,900
Services	59,400	48,600
Government	110,700	37,400
Total	783,200	153,900

Source: California EDD 2001

IMPACTS

Staff reviewed the EAEC Application for Certification (AFC), dated March 2001, the Data Adequacy Response Set 1 dated May 1, 2001, and Supplement B to EAEC AFC dated October 9, 2001. The Applicant used appropriate public databases in the analysis contained in the AFC. Staff's analysis is based on verified information from the AFC and independent research.

EMPLOYMENT

During the engineering, procurement, and construction periods extending twenty-six months, peak employment at the proposed project site would be 400 workers, including 365 craft workers and 35 contractor staff. The peak construction employment of 400 represents a small proportion of all construction jobs in Alameda and Contra Costa Counties (.005 percent), and the labor pool also extends to San Joaquin County. Thus, no difficulty is expected in finding a construction labor force within commute distance for the proposed project, and few if any workers would be expected to relocate to the East Altamont area or Alameda County as a result of the project. Estimated construction payroll would be $49 million. Secondary jobs for local workers in other services and trades would likely be created during the construction period (EAEC 2001a, AFC page 8.8-15).

The permanent employment associated with the proposed project is approximately 40 full-time workers, with an estimated annual operational payroll of $1.7 million. Within the large labor force of Alameda County, this will not have a significant impact. Approximately $5 million would be spent locally on supplies generating $400,000 in sales tax, of which Alameda County would accrue about $50,000 (EAEC 2001a, AFC, page 8.8-17).

HOUSING

As cited previously, construction of the proposed project is not expected to result in workers moving to the area for construction or permanent jobs. Even if a few workers were attracted to the area as a result of cumulative construction opportunities, their impact on a housing market containing over approximately 26,500 (5 percent availability rate for 530,000 total housing units) available housing units in Alameda County would be indiscernible. In addition, Alameda and adjacent counties have mobile home and RV parks, and approximately 14,000 motel and hotel units to provide temporary living opportunities.

SCHOOLS

Because of the large resident labor force available for construction and small permanent labor force that will operate the proposed project, there will be little if any enrollment impacts on the Mountain House Elementary or the Tracy Unified School Districts. Based on a total of 51,150 square feet of covered and enclosed space and an assessment of $0.33 per square foot, a one-time school impact fee of $16,879 will be generated by the project (EAEC 2001e, page 21).

Utilities, Emergency and Other Services

PG&E will provide natural gas via a distribution line that runs at an angle from west to south of the site, and electricity to the EAEC for initial start-up will be provided by the Western Area Power Administration. Once the facility is operating, it will use some of the power generated to run the facility. Water for the proposed facility will be provided by the Byron-Bethany Irrigation District. Wastewater for sanitary purposes will be treated with a septic system and leachfield. Pacific Bell will provide phone service. Each of these utility providers can meet the needs of the EAEC with existing systems.

The project owner will provide on-site security. Project construction and operation may result in a small number of increased calls to the Alameda County Sheriff and Fire Departments, but based on information from the Sheriff's Department, staff does not expect the EAEC will cause a significant impact on law enforcement services and response times (Alameda County 2001).

Fiscal

The capital investment in the EAEC is estimated to be $400 to $500 million (EAEC 2001a, AFC, page 8.8-9). Construction of the proposed project will generate one-time sales tax receipts of $400,000 to $800,000. Based on a 1.0 percent property tax rate, plus any existing bonds or special assessments, and given a facility assessed value of $500 million, Alameda County would receive between $5 and $6.5 million annually.

Socioeconomics Table 2 provides a breakdown of how property taxes would be distributed within Alameda County assuming the property tax is $5 million per year.

SOCIOECONOMICS TABLE 2
Estimated Incremental Property Tax for East Altamont Energy Center

Taxing Jurisdictions	Approximate Share of Tax Increment	Approximate Incremental Revenue
1005 - County General Tax	54.22%	$2,700,000
3001 - San Joaquin College	3.64%	$182,000
3048 - Mountain House School	3.34%	$167,000
3077 - Tracy Unified School District	9.89%	$494,500
3998 - Mountain House Area-wide	6.27%	$313,500
4006 - County Superintendent of School	0.16%	$8,000
4007 – County Superintendent of School	0.60%	$300,000
4008 – County Superintendent of School	0.01%	$5,000
4009 – County Superintendent of School	0.08%	$40,000
4010 – County Superintendent of School	.25%	$12,500
4011 – County Superintendent of School	0.05%	$2,500
4012 – County Superintendent of School	0.16%	$8,000
4013 – County Superintendent of School	0.12%	$6,000
4015 – County Superintendent of School	0.14%	$7,000
4020 – County Superintendent of School	0.03%	$1,500
7005 – County Library	6.89%	$344,500
7006 – County Library District One	0.24%	$12,000
7010 – County Fire Department	8.71%	$435,500
7070 – County Flood	0.32%	$16,000
7106 – Flood Zone 7 State Water	3.27%	$163,500
7115 – Bay Area Air Quality Management	0.32%	$16,000
7135 – Mosquito Abatement	0.21%	$10,500
7165 – Bay Area Rapid Transit	0.95%	$47,500
7375 – Alameda County Resource Conservation	0.04%	$2,000
TOTALS **Numbers Are Not exact due to Rounding**	**96.32%**	**$5,115,500**

Source: Estimates based on applicants projections of property value and AlamedaCounty Auditor-Controller Allocation Factors.

The operation of the facility would entail a budget of $8 million annually with an estimated $5 million remaining in the County for the purchase of materials and supplies. The annual payroll would be approximately $1.7 million a year. In addition, the annual maintenance budget would be approximately $9.5 million (EAEC 2001a, AFC pages 8.8-15 & 16). The allocation of property taxes may change in January 2003 based on a recent decision by the California State Board of Equalization that could affect how taxes are allocated to the various districts (State of California 2001). However the allocation is altered, the EAEC will continue to provide property tax revenue to Alameda County.

ENVIRONMENTAL JUSTICE SCREENING ANALYSIS

The purpose of the environmental justice screening analysis is to determine whether there exists a low-income and/or minority population within the potential affected area of

the proposed site. Staff conducted the screening analysis in accordance with the "Final Guidance for Incorporating Environmental Justice Concerns in EPA's NEPA Compliance Analysis (Guidance Document) dated April 1998. Minority populations, as defined by this Guidance Document, are identified where either:

- The minority population of the affected area is greater than fifty percent of the affected area's general population; or

- 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.

Energy Commission staff has determined the potential affected area as a six-mile radius of the proposed EAEC site. The six-mile radius is consistent with the radius used for staff's cumulative air quality analysis. When a minority and/or low-income population is identified per the above, staff in the technical areas of air quality, public health, hazardous materials, noise, water, waste, traffic and transportation, visual resources, land use, socioeconomics and transmission line safety and nuisance consider possible impacts on the minority/low-income population as part of their analysis. This "environmental justice" (EJ) analysis consists of identification of significant impacts (if any), identification of mitigation, and determination of whether there is a disproportionate impact if an unmitigated significant impact has been identified. Staff's environmental justice approach includes providing notice (in appropriate languages) of the proposed project and opportunities for participation in public workshops to minority and/or low-income communities, and providing information on staff's EJ approach to minority and/or low-income persons who attend staff's public workshops.

Socioeconomics Figure 1 identifies census blocks within six miles of the proposed project that had minority populations greater than 50 percent. However, given the predominately agricultural nature of the area, the number of individuals within the census blocks is small (see **Socioeconomics Figure 1)**.

The percent of population considered low-income or living below the poverty level ranges from 16 percent in San Joaquin County to 7 percent in Contra Costa County. In 1990, the percentage of the population living below the poverty level was 10 percent within a six-mile radius of the EAEC. This percentage is well below the threshold of greater than 50 percent that staff uses to determine if there is a significant low-income population.

Census 2000 data indicate that the minority population within the six mile radius of the project site is 34 percent. However, there are areas that have two or more contiguous census blocks with a minority population greater than 50 percent. Staff considers these areas to be pockets of predominately minority populations, therefore various technical staff will consider environmental justice impacts in their analyses.

Property Values

Neighbors of projects similar to the proposed project have expressed concerns that the project will affect their property values. To address such concerns, on a previous project staff contracted for a study to determine the potential property value impacts

associated with natural gas-fired power plants. As a result of the study, staff found that there is no information or study that demonstrates an adverse or negative impact on surrounding property values directly attributable to a natural gas-fired power plant. Moreover, the EAEC area already contains a number of transmission lines and a substation. Based on this information, staff does not expect the proposed project will cause a significant adverse impact on property values in the vicinity.

CUMULATIVE IMPACT

The EAEC is located in a rather remote part of the Tri-County area. Staff is reviewing two additional power plant applications for projects in the area, the Tracy Peaker Project (169MW) and the Tesla Power Plant (1,120 MW). The Tracy project is approximately eight miles southeast of the EAEC, while Tesla is about six miles south. Construction of the EAEC and Tesla will overlap for almost two years from June 2002 until April 2004. At peak construction in the spring and summer of 2003, the two projects will require about 1,370 employees. Given the 28,000 construction workers available in the Tri-County area, there will be a sufficient pool of workers to construct the facilities. With respect to the Tracy Peaker Project, construction is scheduled to take place from November 2001 until July 2002. Thus, this project will overlap with Tesla and EAEC for a couple of months. Approximately 120 workers will be employed at the Tracy site during peak construction in June 2002. Staff believes that there will be a sufficient number of workers available from the Tri-County area for all three power projects.

Staff anticipates that almost all workers will commute from their homes in the Tri-County area and therefore will not have any significant impact on population growth, housing, schools, or public services. The projects will have a beneficial fiscal impact in terms of property taxes, employment, purchase of materials and supplies, and general economic growth.

The only other significant project is the Mountain House residential subdivision east of the proposed project site in San Joaquin County. Construction of the initial subdivision is underway, and full build-out may result in a residential population of 40,000 residents within thirty to forty years (EAEC 2001a, AFC page 8.8-18, Hitchcock 2001). Staff agrees with the Applicant that because of the size of the construction workforce in the Tri-County area, the phased development of the Mountain House subdivision, and the relatively minor overlap of building trades, there will not be adverse cumulative employment, housing or school impacts involving the EAEC.

FACILITY CLOSURE

UNEXPECTED PERMANENT CLOSURE

Should the plant be permanently closed, the beneficial socioeconomic impacts such as worker payroll, project expenditures, local economic stimulus, and property tax revenues would no longer occur. The EAEC AFC (Section 4, pages 4.1 & 2) describes what will happen if the plant is shutdown or closed prematurely. The planned lifetime of the proposed power plant is thirty years; however, given unforeseen circumstances the plant may be retired prematurely for a variety of reasons. This could include the determination that the plant is no longer economically viable.

UNEXPECTED TEMPORARY CLOSURE

Should the plant be temporarily shutdown or closed, there would not be any significant socioeconomic impacts. The Applicant would conduct a review to determine if there had been any environmental damage or release of hazardous materials. If not, the plant could be mothballed. Before the plant begins commercial operation, the Applicant will develop a contingency plan to deal with premature or unexpected closures. This would include communication with the Energy Commission, Alameda County, and local agencies regarding schedule of facility closure and compliance with LORS.

PLANNED CLOSURE

In the event that the decision is made to permanently close the facility, the Applicant will develop a plan for decommissioning that will be submitted to the Energy Commission and other appropriate agencies. The plan will include compliance with all applicable LORS. Should the plant be permanently closed, the beneficial socioeconomic impacts such as worker payroll, project expenditures, local economic stimulus, and property tax revenues would no longer occur.

MITIGATION

Energy Commission staff has identified economic and fiscal benefits to the project area such as employment, project expenditures and sales and property tax revenues. To ensure that the local area benefits from the project, staff is proposing a condition of certification that will lead to local employment and project-related expenditures. A condition is proposed to ensure that the project owner pays the Tracy Unified School District a one-time school impact fee of $16,879 (See Condition of Certification **SOCIO-1**).

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

Staff believes that the EAEC will not cause a significant adverse direct or cumulative impact on housing, employment, schools, public services or utilities. The EAEC will benefit the local and Tri-County area in terms of an increase in jobs and commercial activity during the construction and operation of the facility. The construction payroll and project expenditures would also have a positive effect on the local and Tri-County economy. The estimated benefits from the project include increases in the affected area's property and sales taxes, employment, and sales of services, manufactured goods, and equipment. The estimated annual operating budget will be $2 to $4 million. Overall, staff believes that the project will have a positive socioeconomic impact on the East Altamont area.

The project, as proposed, would be consistent with all applicable Socioeconomic LORS. In particular, the EAEC is consistent with Policies 50 and 262 of the East Alameda County Area Plan regarding the use of local labor, and facilitating the provision of adequate electric service facilities. The proposed conditions of certification ensure the compliance with LORS and that anticipated local benefits occur to the extent feasible.

RECOMMENDATIONS

If the Energy Commission certifies the proposed project, staff recommends that it adopt the following conditions of certification.

PROPOSED CONDITIONS OF CERTIFICATION

SOCIO-1 The project owner and its contractors and subcontractors shall recruit employees and procure materials and supplies within the Tri-County first unless:

- to do so will violate federal and/or state statutes;
- the materials and/or supplies are not available;
- qualified employees for specific jobs or positions are not available; or
- there is a reasonable basis to hire someone for a specific position from outside the local area.

Verification At least sixty (60) days prior site mobilization, the project owner shall submit to the Energy Commission Compliance Project Manager (CPM) copies of contractor, subcontractor, and vendor solicitations and guidelines stating hiring and procurement requirements and procedures. In addition, the project owner shall notify the CPM in each Monthly Compliance Report of the reasons for any planned procurement of materials or hiring outside the local regional area that will occur during the next two months.

SOCIO-2 The project owner shall pay the one-time statutory school facility development fee as required at the time of filing for the in-lieu building permit with the Alameda County Building Department.

Verification: The project owner shall provide proof of payment of the statutory development fee in the next Monthly Compliance Report following the payment.

REFERENCES

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SOIL AND WATER RESOURCES

Lorraine White, John Scroggs, Jim Henneforth and John Kessler

INTRODUCTION

This section analyzes potential effects on soil and water resources by the East Altamont Energy Center (EAEC), as proposed by East Altamont Energy Company, LLC (Applicant). The analysis specifically focuses on the potential for the project to cause impacts in the following areas:

- Whether construction or operation will lead to accelerated wind or water erosion and sedimentation.
- Whether the project will exacerbate flood conditions in the vicinity of the project.
- Whether the project's demand for water will adversely affect surface or groundwater supplies.
- Whether project construction or operation will lead to degradation of surface or groundwater quality.
- Whether the project will comply with all applicable laws, ordinances, regulations and standards.
- Where the potential for impacts is identified, staff has proposed mitigation measures to reduce the significance of the impact and, as appropriate, has recommended conditions of certification.
- Solid waste disposal is also discussed in the **Waste Management** section, as are land use effects in the **Land Use** section of this Staff Assessment.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

FEDERAL

Clean Water Act

The Clean Water Act (33 U.S.C. section 1257 et seq.) requires states to set standards to protect water quality through the regulation of point source and certain non-point source discharges to surface water. These discharges are regulated through requirements set forth in specific or general National Pollutant Discharge Elimination System (NPDES) Permits. Stormwater discharges during construction and operation of a facility, and incidental non-stormwater discharges associated with pipeline construction also fall under this act , and are normally addressed through a general NPDES permit. In California, requirements of the Clean Water Act regarding regulation of point-source discharges and stormwater discharges are delegated to, and administered by, the nine Regional Water Quality Control Boards (RWQCBs).

Section 404 Permit to Place or Discharge Dredged or Fill Material

Section 404 of the Clean Water Act regulates the discharge of dredged or fill material into waters of the United States, including rivers, streams and wetlands. The Army

Corps of Engineers (ACOE) issues site-specific or general (nationwide) permits for such discharges.

Section 401 Water Quality Certification

Section 401 of the Clean Water Act provides for state certification that federal permits allowing discharge of dredged or fill material into waters of the United States will not violate federal and state water quality standards. These certifications are issued by the RWQCBs. Proposed linear facilities can cross ephemeral drainages that are considered waters of the United States.

Encroachment Permit from USBR and the San Luis Delta-Mendota Water Authority

In order to accommodate directional drilling for routing the fresh water supply pipeline under the Delta-Mendota Canal, the Applicant will need to obtain an Encroachment Permit from the United States Bureau of Reclamation (USBR) and Delta-Mendota Water Authority. The USBR manages the Delta-Mendota Canal as a component of the Central Valley Project (CVP), and is responsible to review and approve plans that could potentially impact the integrity of the canal.

STATE

Porter-Cologne Water Quality Control Act

The Porter-Cologne Water Quality Control Act of 1967, Water Code section 13000 et seq., requires the State Water Resources Control Board (SWRCB) and the nine RWQCBs to adopt water quality criteria to protect state waters. These criteria include the identification of beneficial uses, narrative and numerical water quality standards, and implementation procedures. The criteria for the project area are contained in the Central Valley Region Water Quality Control Plan. These standards are typically applied to the proposed project through the Waste Discharge Requirements (WDRs) permit. The Porter-Cologne Water Quality Control Act also requires the SWRCB and the nine RWQCBs to ensure the protection of water quality through the regulation of waste discharges to land. Such discharges are regulated under Title 23, California Code of Regulations, Chapter 15, Division 3. These regulations require that the RWQCB issue Waste Discharge Requirements specifying conditions regarding the construction, operation, monitoring and closure of the waste disposal site, including injection wells and evaporation ponds for waste disposal.

California Water Code

Section 13551 of the Water Code prohibits the use of "…water from any source of quality suitable for potable domestic use for non-potable uses, including …industrial… uses, if suitable recycled water is available…" given conditions set forth in Section 13550. These conditions take into account the quality and cost of the water, the potential for public health impacts and the effects on downstream water rights, beneficial uses and biological resources.

Section 13552.6 of the Water Code specifically identifies that the use of potable domestic water for cooling towers, if suitable recycled water is available, is an unreasonable use of water. The availability of recycled water is based upon a number

of criteria, that must be taken into account by the SWRCB. These criteria are that: the quality and quantity of the reclaimed water are suitable for the use; the cost is reasonable, and the use is not detrimental to public health, will not impact downstream users or biological resources, and will not degrade water quality.

Section 13552.8 of the Water Code states that any public agency may require the use of recycled water in cooling towers if certain criteria are met. These criteria include that recycled water is available and meets the requirements set forth in section 13550; the use does not adversely affect any existing water right; and if there is public exposure to cooling tower mist using recycled water, appropriate mitigation or control is necessary.

State Water Resources Control Board Policies

The SWRCB has also adopted a number of policies that provide guidelines for water quality protection. The principle policy of the SWRCB which addresses the specific siting of energy facilities is the Water Quality Control Policy on the Use and Disposal of Inland Waters Used for Power plant Cooling (adopted by the Board on June 19, 1976 by Resolution 75-58). This policy states that use of 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. This SWRCB policy requires that power plant cooling water should come from, in order of priority: wastewater being discharged to the ocean, ocean water, brackish water from natural sources or irrigation return flow, inland waste waters of low total dissolved solids, and other inland waters. This policy also addresses cooling water discharge prohibitions.

Water Supply Permit

Under Title 22 of the California Code of Regulations, the California Department of Health Services reviews and approves surface water treatment systems that serve the domestic water needs of more than 25 people daily, 60 days out of the year. This program is administered through the Drinking Water Program.

Tertiary Wastewater Treatment Permit

Under Title 23 of the California Code of Regulations, the California Department of Health Services reviews and approves wastewater treatment systems to meet tertiary treatment standards, allowing recycled use of water for industrial processes such as for steam production and cooling water.

LOCAL

County of Alameda

The EAEC and portions of the proposed water and recycled water lines are located in Alameda County. The Energy Commission will require a Grading and Excavation Permit consistent with the requirements of Alameda County Public Works Agency. The application for the Grading and Excavation Permit will include review of the Erosion Control Plan. In addition, the Energy Commission will require a waste disposal permit for the septic system for disposal of sanitary waste, consistent with the requirements of Alameda County Environmental Health Department.

County of Contra Costa

Proposed fresh water lines on the northern portion of Bruns Road and Byron Bethany Road are located in Contra Costa County. The Energy Commission will require a Grading and Excavation Permit consistent with the requirements of Contra Costa County Public Works Department. The application for the Grading and Excavation Permit will include review of the Erosion Control Plan. In addition, a building permit will be necessary for the proposed pump station that will withdraw fresh water from Byron Bethany Irrigation District's (BBID's) Canal 45.

County of San Joaquin

Proposed recycled water lines on the east end of Kelso Road are located in San Joaquin County. The Energy Commission will require a Grading and Excavation Permit consistent with the requirements of San Joaquin County Community Development Department. The application for the Grading and Excavation Permit will include review of the Erosion Control Plan.

ENVIRONMENTAL SETTING

REGIONAL AND VICINITY DESCRIPTION

The Applicant proposes to build the East Altamont Energy Center (EAEC), a 820 MW combined cycle plant augmented by 245 MW of duct firing, in Alameda County. The EAEC is proposed to be constructed within 40 acres of a 174-acre parcel being acquired by the Applicant. Currently, the site is being used for grazing, and to farm oats, alfalfa, and hay crops, and occasionally row crops like tomatoes. The proposed site is located approximately 8 miles northwest of the City of Tracy, 12 miles east of Livermore, 5 miles south of Byron, and less than 1 mile from Mountain House Community Service District (MHCSD), a new town starting Phase I construction. Characterized by relatively flat topography with rolling hills, the site is located east of the Altamont Pass more than 1-mile from the base of the Mount Diablo Range. An existing drainage channel runs along the eastern boundary of the site and discharges to the north of the EAEC site into the intake channel of the Delta-Mendota Canal. (EAEC 2001a, AFC Section 8.4 & 8.15)

The land use in the vicinity of the EAEC is primarily agricultural situated around significant water supply, natural gas and power generation and transmission facilities of statewide importance. Within the direct vicinity of the project are the Western Area Power Administration Substation, intake structures and pumping stations for the two most significant water supply conduits in the state, the Central Valley Project's (CVP's) Delta-Mendota Canal and the State Water Project's (SWP's) California Aqueduct, PG&E's gas compressor station, numerous windfarms, and four 500-kV and nine 230-kV transmission lines. Several residences exist within one mile of the proposed EAEC site. (EAEC 2001a, AFC Section 8.4)

Several new linear facilities will also be required. Please refer to Project Description Figure 2.1-1 for an illustration of the proposed project. The preferred routes for each are described as follows:

1. The Raw Water Pipeline, consisting of approximately 2.1 miles of 24-inch diameter pipeline would draw water from Byron-Bethany Irrigation District's Canal 45, which is supplied water from the intake channel to the California Aqueduct. The pipeline would be installed southward along Bruns Road for about 0.5 miles, then along an existing gravel road that runs east to the Delta-Mendota Canal, then under the Delta-Mendota Canal and across Mountain House Road to reach the project site. The pipeline crossing under the Delta-Mendota Canal would require trenchless technology to directional drill under the canal.

2. The Recycled Water Pipeline, as proposed for supply from MHCSD, would consist of approximately 4.6 miles of 24-inch pipeline installed from the site of the future MHCSD wastewater treatment plant. The pipeline would run west along Bethany Road, and then northwest along Byron-Bethany Road to the project site.

3. The Natural Gas Pipeline, consisting of approximately 1.4 miles of 20-inch pipeline, would tie-in to PG&E's Main Pipeline inside PG&E's compressor station. The pipeline would run south out of the compressor station, crossing and then running east along Kelso Road, then turning north on Mountain House Road to the project site.

(EAEC 2001a, AFC Section 2.0)

SOILS

As stated above, the 174-acre site being acquired by the Applicant is currently in active agricultural production. All of the land is classified as prime farmland, as is most of the surrounding area. Within the 40-acre portion proposed for development, the EAEC site is gently sloped, naturally decreasing in elevation in a diagonal direction to the northeast. It ranges in elevation up to about 40 feet above mean sea level (msl) in the southwest corner to as low as 31 feet msl in the northeast corner.

Rincon Clay Loam is the primary soil type covering the entire EAEC site. Soil types for the linear facilities tend to be similar to Rincon Clay Loam, primarily consisting of San Ysidro Loam for the Raw Water Pipeline, Stomar Clay for the Recycled Water Pipeline and San Ysidro Loam for the Natural Gas Pipeline. This well-drained soil is formed in alluvium from sandstone and shale on nearly level valleys and fans. Shrink-swell potential is moderate to high, which will require consideration in design and construction of equipment foundations.

Soils and Water Table 1
Soil Types Affected & Characteristics

Project Element	Primary Soil Name	Slope Class %	Depth Range	USDA Texture	Parent Material	Water Erosion Hazard	Permeability	Drainage	Revegetation Potential
EAEC Plant	Rincon Clay Loam (Rd)	0 – 3%	0 – 16 in.	Clay Loam	Alluvium from sedimentary rocks	Slight	Slow	Well Drained	Very Good
Water Line	San Ysidro Loam (Sc)	0 – 2%	0 – 15 In.	Loam	Alluvium from sedimentary rocks	Fair	Very Slow	Moderately Well Drained	Fair
Recycled Water Line	Stomar Clay Loam (252)	0 – 2%	0 – 17 in.	Clay Loam	Alluvium from sedimentary rocks	Slight	Slow	Well Drained	Good
Natural Gas Line	San Ysidro Loam (Sc)	0 – 2%	0 – 15 In.	Loam	Alluvium from sedimentary rocks	Fair	Very Slow	Moderately Well Drained	Fair

Although erosion potential from water is slight, the area is subject to prevailing winds that could erode loose soils during construction. (EAEC 2001a, AFC Sections 8.4 and 8.9)

SOIL AND WATER CONTAMINATION

A Phase I Environmental Site Assessment (Phase I ESA) prepared for the EAEC site identifies three recognized environmental conditions of potential concern associated with previous agricultural activities, all in the vicinity of an existing house and maintenance yard located on the southwest portion of the 174-acre parcel. They include the following:

1. Former location of the underground gasoline tank adjacent to the maintenance shed where there is no documentation of contamination to soil or groundwater, although the property owner recalls there may have been some leakage around the pipe fittings.

2. Pesticide container storage in the former chicken coop where 5-gallon containers of apparent pesticide and herbicide appear to be leaking and in poor condition;

3. Waste oil/fuel storage area, where two above-ground tanks and buckets of waste oil are located and releases to the soil are visible.

During the September 6, 2001 Data Response Workshop in Livermore, the Applicant clarified that none of the material recognized conditions were located in the vicinity where disturbance was planned for construction of the EAEC. (EAEC 2001v, Attachment WR-1)

GROUNDWATER

The proposed EAEC site lies within the Mountain House alluvial fan, which is approximately 150 to 200 feet thick at the site. Shallow groundwater in the Mountain House area moves from the upper reaches of the alluvial fan towards surface water

features in the low-lying Delta areas. Available groundwater information near the proposed project site indicates that shallow groundwater occurs at depths of 0 to 10 feet below grade. Groundwater movement is very slow, due to lack of irrigation pumping, permeability, and high water table in the Delta. Vertical groundwater movement is impeded by a relatively thin water-bearing section of less than 200 feet above the poorly permeable and strongly confined deeper aquifers. Groundwater recharge in the area occurs from percolation of applied irrigation water and canal seepage losses. Because of the shallow groundwater, farmers frequently tile their fields to enhance drainage and protect crops from root damage. A similar deep aquifer, the Kellogg Creek alluvial fan, is used for potable supply at the Discovery Bay and Brentwood communities, approximately 8 miles north of the site. Quality and yield in that area are good.

Groundwater of variable quality is typical in the area of the proposed project. Locally, shallower wells provide low-quality water to individual domestic users. Deeper wells provide better quality to communities including Brentwood, Discovery Bay and Tracy, and to local irrigators. The available data characterizing groundwater quality is limited, but is described as follows:

Soils and Water Table 2
Groundwater Quality

Constituent Group	Constituent	Units	Measure
Cations	Calcium	mg/l	120
	Magnesium	mg/l	98
	Sodium	mg/l	760
	Potassium	mg/l	3.4
	Manganese	mg/l	10
Anions	Sulfate	mg/l	640
	Chloride	mg/l	980
	Fluoride	mg/l	0.3
	Nitrate	mg/l	14
Metals	Arsenic	ìg/l	6
	Manganese	ìg/l	10
Other	Hardness as Ca CO3	mg/l	700
	Conductivity	ìmhos/cm	4570

Note: Data from well 01S/04E-33M01, sampled on 6-6-79 (Keeter, 1980).

As can be observed in **Soils and Water Table 2**, the overall quality of this groundwater sampled from an unknown depth, could be described as being particularly high in salinity and hardness. Although a concentration for Total Dissolved Solids (TDS) was not available from this particular sample, a representative TDS concentration might be indicative from groundwater pumped by City of Tracy, which has concentrations on the order of 750 mg/l. (EAEC 2001a, AFC Section 8.14) and (CEC 2001g, page 1)

SURFACE WATER HYDROLOGY

The climate in the project area is typical of the Central Sacramento Valley with hot dry summers and mild winters. Daytime temperatures during the summer months range between 80°F and 100°F, with peak days up to 110 °F. The rainy season generally extends from November through March. Average precipitation is about 12 inches. Total elevation range on the 174-acre site is from 20 to 60 feet above mean sea level, while elevation on the 40-acre portion proposed for development of the EAEC ranges from about 30 to 40 feet. The proposed project site is located near the southwestern edge of the Sacramento-San Joaquin River Delta. The area is characterized by a series of natural and man-made stream channels, canals and drains that form a web of low-lying islands. The foothills of the Coast Range are approximately 3 miles southwest of the site and generally define the southwestern edge of both groundwater and surface water resources. High-quality surface water resources characterize the project site and the southern Delta.

Soils and Water Table 3
Average Monthly Precipitation near the EAEC Site

Precip.	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
(inches)	2.38	1.92	1.71	0.80	0.22	0.14	0.05	0.10	0.26	0.67	1.88	1.72

Because of its location near the confluence of the state's two major river systems, the area surrounding the project site has abundant surface water features. In addition to the natural river systems, the diversion facilities for both the Central Valley Project (CVP) and State Water Project (SWP) are located within several miles of the project site. The SWP draws its water from Clifton Court Forebay through the Skinner Fish Screen into the intake channel and is then pumped into the Aqueduct via the Harvey O. Banks Pumping Plant. From a separate point of diversion, the CVP also draws its water from Clifton Court Forebay through the Tracy Fish Screen into its intake channel and is then pumped into the Delta-Mendota Canal via the Tracy Pumping Plant. These aqueducts, supported by various storage reservoirs, convey nearly 6,000,000 acre-feet/year of municipal, industrial and agricultural water to the southern portion of California and play a significant role in the movement of water throughout the state. Because of its high quality and ready access, surface water is extensively used in the project area. An estimated 1,700,000 acre-feet/year of water from the Delta is diverted by local water users. (EAEC 2001a, AFC Section 8.14)

EAEC WATER SUPPLY

For much of the life of the project, the Applicant proposes to use all fresh water supplied by Byron-Bethany Irrigation District (BBID) for its steam production and for cooling through use of a mechanical draft evaporative cooling tower (wet cooling). BBID is a multi-county irrigation district established under Water Code Division 11 primarily to provide water to portions of lands in Alameda, Contra Costa and San Joaquin Counties near their junction. Currently, BBID primarily supplies agricultural water supplies in its service area, with one current industrial user - Unimin Corporation - using water for aggregate mining and processing. The distribution system is segregated into two divisions: the Byron Division (north of the SWP Intake Channel) and the Bethany Division (south of the SWP Intake Channel). BBID maintains two diversions within the SWP Intake Channel, located between the Skinner Fish Screen and Harvey Banks

Pumping Plant, with one each dedicated for supplying the Bethany Division and the Byron Division. Open canals and pump stations makeup the primary distribution system, with some pipelines for supply to BBID customers.

The water quality of BBID's fresh water supply varies according to season and hydrologic conditions in the Delta, and is characterized in the following ranges:

Soils and Water Table 4
BBID's Fresh Water Quality

Constituent	Range of Water Quality (mg/l)
Total Dissolved Solids	110 to 300
Alkalinity	40 to 95
Arsenic	0.001 to 0.003
Boron	<0.1 to 0.4
Bromide	0.04 to 0.21
Calcium	11 to 25
Total Organic Carbon	3 to 7
Chloride	18 to 67
Copper	<0.005 to 0.02
Hardness	48 to 118
Magnesium	2 to 14
Selenium	<0.001 to 0.001
Sodium	17 to 65
Sulfate	14 to 59

Note: Data based on monthly grab sample data collected from the SWP Intake Channel during 1995, 1996, and 1997 (through August); Data supplemented with grab sample data collected from SWP Intake Channel in July 1999; (EAEC 2001p, Recycled Water Feasibility Study)

BBID's water rights

BBID's entitlement to fresh water is under a Pre-1914 Appropriative Water Right, established originally by its predecessor, Byron-Bethany Irrigation Company, by filing a Notice of Appropriation of Water in Contra Costa County on May 18, 1914. The original point of diversion was from Italian Slough, a tributary to Old River. BBID's point of diversion was changed to the intake channel of the California Aqueduct under agreement with DWR dated May 4, 1964 because development of the State Water Project (SWP) was going to displace the previous point of diversion. The AFC indicates BBID's normal maintenance schedule for their canals requires them to be shut down from November through March for cleaning of aquatic weeds and canal bank reshaping. To facilitate a more continuous operation of BBID's facilities, concrete canal lining and a water control structure will be used in the section of BBID's Canal 45 that is used for water supply to EAEC. The amount of water BBID claims to maintain under its Pre-1914 Appropriative Water Right for reasonable and beneficial use is 60,000 acre-feet/year. The water put to beneficial use by BBID during 2000 was 31,700 acre-feet. The Applicant has represented that BBID, through conservation and recent reductions in agricultural customer diversions, has reduced its water use from historic highs, and use by EAEC combined with use by BBID's other customers, would be within historic patterns of use. (EAEC 2001a, AFC Sections 7.1.6 and 8.14.2) At this time, staff has

been unable to verify the historic level of water savings by BBID through conservation and or agricultural customer reduction measures.

BBID's historic diversions, 1980 – 1996, are summarized as follows:

Soils and Water Table 5
BBID's Historic Annual Diversions, 1980 - 1996

Year	Annual Quantity of Water Diverted (Acre-Feet)
1980	39,238
1981	40,390
1982	33,683
1983	24,023
1984	39,369
1985	32,405
1986	30,067
1987	35,438
1988	41,126
1989	37,355
1990	42,963
1991	37,214
1992	38,507
1993	33,175
1994	38,657
1995	25,060
1996	30,065

Note: Annual historic diversion data as supplied by BBID to DWR (CEC 2001i)

Recycled water

EAEC also proposes that as recycled wastewater becomes available from the Mountain House Community Services District (MHCSD) wastewater treatment plant, BBID will supply recycled water to the extent it is available to reduce use of fresh water. The Mountain House community is a planned residential development, which is currently under construction. Current construction includes the first of twelve phases of residential development, a water treatment plant and a wastewater treatment plant. Mountain House will receive raw water from BBID for treatment before supply to its residents, and its wastewater will be treated to Title 22 tertiary standards before being made available as recycled water to BBID for supply to EAEC.

Mountain House is expected to achieve buildout by approximately 2020, and at such time, is projected to supply about 2,884 acre-feet/year of recycled water to EAEC. The projected availability of recycled water from MHCSD is expected to meet a portion of EAEC's total average water supply needs ranging from 11% in 2005, to as much as 62% in 2020 and thereafter. MHCSD also plans to use recycled water itself for two planned parks and a golf course. MHCSD estimates that at buildout, it will produce recycled water at a capacity of about 5.4 mgd. Subject to actual development,

projections of total recycled water compared to the portions that would be used by MHCSD and EAEC are as shown according to the following schedule:

Soils and Water Table 6
Projected Availability of MHCSD Recycled Water Supply (acre-feet/year)

Year	2000	2005	2010	2015	2020	2025	2030	2035	2040
Total	0	1,483	2,965	4,448	5,930	5,930	5,930	5,930	5,930
MHCSD Use	0	983	1,155	1,953	3,046	3,046	3,046	3,046	3,046
EAEC Supply	0	500	1,810	2,495	2,884	2,884	2,884	2,884	2,884

(EAEC 2001p, Recycled Water Feasibility Study)

In response to staff data requests, the applicant has acknowledged the uncertainty of this projected schedule (see applicants objections to staff's data request #89, docketed July 30, 2001). When asked to do an analysis of the likelihood that the Mountain House new town development will proceed as expected, the applicant objected that the request was "burdensome as it would involve expenditure of substantial resources for information that would be speculative at best." Although staff supports the use of recycled water to displace the use of fresh water for cooling purposes, staff contends that the amounts and timing of MHCSD's recycled water supply is speculative and actual development of this resource is subject to many factors and uncertainties beyond the control of the applicant.

Water Uses

EAEC's total annual water demands are projected to be 4,616 acre-feet/year on an average annual basis (4.0 mgd average daily flow), and up to 7,000 acre-feet/year on a peak annual basis (9.1 mgd peak daily flow). Average daily water requirements of 4.0 mgd are based on the combined cycle plant operating at 820 MW at an ambient temperature of 61 deg. F without duct firing or steam injection. Peak daily water requirements of 9.1 mgd are based on the combined cycle plant operating at 1,065 MW at an ambient temperature of 98 deg. F with maximum duct firing and steam injection.

Water use for the proposed EAEC is divided into four main levels based on the quality required: 1) Water for the circulating or cooling water system; 2) Service water for the plant, which includes all other miscellaneous uses; 3) Demineralized water for makeup to the Heat Recovery Steam Generators (HRSG's) and auxillary boilers; and 4) Potable water for drinking and lavatory use. Cooling water (representing 99 percent of the project's overall water demand during normal operations) will be obtained primarily from using raw fresh water or recycled water as-is without further treatment (and depending on the quality of the recycled water source). Cooling water will be supplemented by use of HRSG blowdown and Reverse Osmosis (RO) permeate following treatment of the cooling tower blowdown. Service water for the plant, including fire water, will be obtained from the cooling tower blowdown stream after filtration and water softening. Demineralized water for makeup to the HRSG's and auxillary boilers will be obtained

from treatment of the cooling tower blowdown reject stream, utilizing distillate from the brine concentration with additional polishing from the mixed bed demineralizer. Potable water will be obtained by treating raw fresh water through a packaged treatment system. EAEC's proposed water treatment system achieves a zero liquid-discharge system for plant wastewater by employing brine concentration and crystallization, yielding a solid waste salt cake that will be disposed of in appropriately classed landfills.

Soils and Water Table 7 summarizes the use of water for EAEC operations, and the discharge of wastewater associated with the proposed EAEC.

Soils and Water Table 7
EAEC Facility Water Balance

Component Stream	Average Day (gpm)	Peak Day (gpm)
Turbine Injection Water	0	*122* (See Note 3)
Cooling Tower Makeup	3,264	6,822
Brine Concentration Distillate fed to HRSG's/ Steam Cycle	*50* (See Note 3)	647
Reuse in Cooling Tower of Liquid Waste Streams	- 451	- 1,058
Demin. Water from Storage	0	*218* (See Note 3)
HRSG Stack	0	*776* (See Note 3)
Total Water Consumption (Net)	**2,813**	**6,411**
Blowdown HRSG's	Recycled To Cooling Tower	Recycled To Cooling Tower
Blowdown Cooling Tower	Recycled to Cooling Tower	Recycled to Cooling Tower
Plant Drainage	Recycled to Cooling Tower	Recycled to Cooling Tower
Brine Concentrator	Recycled to Cooling Tower & HRSG's	Recycled to Cooling Tower & HRSG's
Sanitary Wastewater	To Leach Field	To Leach Field
Total Wastewater (Net)	**0**	**0**

Notes:
1. Blowdown from the cooling tower reflects 7 cycles of concentration.
2. Flow rates reflect conditions using 100% fresh water.
3. Denotes quantity already accounted for in Water Balance;

Source: (EAEC 2001a, AFC Section 8.14)

Cooling process

The EAEC is proposed to be a nominal 1,100MW natural gas fired combined cycle generating facility. The generating facility will consist of three combustion turbine generators (CTGs) and one steam turbine generator (STG). The CTGs will each generate approximately 180MW (540 MW total) at base load conditions under average ambient conditions. The hot exhaust gases from the CTGs will be used to generate steam in HRSGs. The units will have the capability to generate additional steam by firing additional fuel with duct burners (duct firing). The steam produced will be admitted to a condensing STG that has the capability to generate an additional 550MW when maximum duct firing is used with the HRSGs. After passing through the STG the steam is exhausted into a condenser where it is cooled and condensed back to water to be pumped back to the HRSGs. The cooling medium for the condenser is water that is

recirculated over the condenser in a mechanical draft evaporative cooling tower. The cooling tower is comprised of 19 cells or fan bays (EAEC 2001a, AFC Section 2).

The plant cooling system consists of a deaerating steam surface condenser, cooling tower, and circulating water system. The heat rejection system will receive exhaust steam from the low-pressure steam turbine and condense it to water for reuse. The surface condenser will be a shell-and-tube heat exchanger with the steam condensing on the shell side and the cooling water flowing in one or more passes inside the tubes. The condenser will be designed to operate at sub-atmospheric pressure, ranging from 1.0 to 5.0 inches of mercury (Hg) depending on ambient temperature and plant load. Approximately 267,300 gpm of circulating water is required to condense the steam at maximum plant load.

The cooling water will circulate through a counter-flow mechanical draft-cooling tower with the water passing over fill media by gravity as air is drawn upward by the use of electric-motor-driven fans to move the air in a direction opposite to the flow of the water. The cooling system must be replenished with “make-up water” to replace water lost to evaporation, drift, and blowdown. The cooling system takes advantage of evaporation to remove heat, but cooling system water is “lost” through the evaporation. As the water flows downward a fine mist of water droplets is entrained in the warm air leaving the tower. This mist is termed “drift” and will be limited to 0.0005% of the circulating water flow by the use of drift eliminators. The evaporation causes the concentration of impurities due to the intensification of solids by the water evaporation loss. Blowdown is the bleeding off of a small percentage of the total flow, so that the new make-up water balances the impurities to stay within system specifications. Blowdown volumes are dependent on the quality of the make-up water and the system specifications regarding the impurities that are in the make-up water. Considering the loss of water from evaporation, drift and blowdown the applicant has estimated the total water requirements of EAEC to be about 4,600 acre-feet per year. During periods when the ambient air temperature is cool and the relative humidity increases, there will be a visible vapor plume that will emanate from the cooling tower.

Process Wastewater

Wastewater produced from various processes at the proposed EAEC, consisting of HRSG blowdown, cooling tower blowdown, brine concentrator effluent and plant drainage, will be treated and returned to the cooling tower basin for reuse. Process wastewater will be managed in a zero liquid-discharge system, which produces no liquid discharge, and only a solid waste consisting of a salt cake, which is hauled off-site for disposal at an appropriately licensed landfill. For a further discussion of the solid waste disposal issues, please refer to the Waste Management section of this document.

A simplified description of the system starts with cooling water blowdown that is passed through a filtration system to remove suspended solids. Filtered cooling tower blowdown will next pass through an ion exchange softening process to remove calcium and magnesium. Waste from the ion exchange softeners will be sent to an equalization tank from which it will be metered slowly to the brine concentrators. Two 50-percent brine concentrators will be used to further concentrate the reject stream, before passing through crystallizers or dryers, where the majority of remaining water will be evaporated leaving a relatively dry salt cake suitable for landfill disposal. Treated water streams

throughout the process are reclaimed for various plant uses. (EAEC 2001y, Supplement B to the Application for Certification)

Sanitary wastewater will be discharged into a septic tank and leach field system, which will be established in a raised bed in order to maintain percolation above groundwater.

Storm Water

Currently, storm water runoff from the project site runs by sheet flow to the north, where it is collected in an east-west running drainage ditch which in turn, discharges into a north-south running drainage ditch that runs along the east side of the property. The north-south running drainage ditch drains to the north and discharges into the intake channel of the CVP's Delta-Mendota Canal. Storm water developed over the 40 acres for the EAEC generation facilities will be managed separately between process and non-process areas.

Open process areas will be curbed to contain the maximum 25-year, 24-hour design storm runoff in addition to the volume of the largest storage container. Storm water drainage will be conveyed to an oil/water separator, and then into the cooling tower basin for reuse.

Storm water from non-process areas will be conveyed through an oil/water separator into the storm water detention pond. The storm water detention pond will serve to temporarily store runoff, and discharge flows into the existing drainage channel along the eastern boundary of the proposed EAEC site, which flows northerly into the intake channel of the Delta-Mendota Canal. The storm water facilities will be sized to accept the 25-year, 24-hour design storm runoff consistent with the criteria specified by the Alameda County Flood Control and Water Conservation District's criteria for sizing storm water facilities.

In order to compare pre and post-project storm water runoff under the change in ground conditions and surface materials, runoff is calculated for 23.7 acres of the site, representative of the non-process portion of area for EAEC, which will discharge its storm water off-site. The calculated pre-project storm water runoff is summarized as follows:

Soils and Water Table 8
Pre-Project Storm Water Runoff

Return Period of Storm (Years)	Rainfall for 24-hour Storm (Inches)	Total Runoff from Site (Millions of Gallons)
10	2.9	0.746
25	3.2	0.824
50	3.8	0.978
100	3.9	1.004

Source: (EAEC 2001a, AFC Section 8.14)

ANALYSIS OF PROJECT RELATED IMPACTS

DIRECT AND INDIRECT IMPACTS

Soil

Linear facilities consisting of the supply pipelines for water, recycled water and natural gas are generally proposed to run along roads or in previously developed utility right-of-ways in order to minimize new disturbance to prime farmlands. Construction BMPs will be implemented for control of wind and water erosion and storm water drainage. Although water erosion potential is slight, the area is subject to prevailing winds that could erode loose soils during construction. Wind erosion will be controlled by watering the loose soil until final soil placement, and compaction is achieved. Excavation and grading may also be suspended during periods of high winds. Other general BMPs employed during construction include the use of temporary drains and swales, silt fencing, hay bale barriers, and sand bag barriers as appropriate.

Following construction, permanent BMPs to linear facilities will include revegetation of disturbed areas using locally prevalent plant species. The EAEC site will be surfaced using either crushed rock, paving or grass, and storm water will flow into grass-lined channels located around the perimeter of the site. Storm water collected by the perimeter channels will pass through an oil/water separator, before being retained in the storm water retention basin. Discharge from the storm water retention basin will be into the existing drainage channel that runs along the eastern boundary of the site, which ultimately drains and discharges to the intake channel of the Delta-Mendota Canal. Hazardous materials will be stored in covered enclosures, or if outside, will have secondary containment, to protect from contamination of storm water. (EAEC 2001a, AFC Sections 2.2 & 8.9) (EAEC 2001p, SWPPP and EAEC 2001x, SWPPP Drawings)

Based on the Applicant-proposed BMPs, no effects to soil are expected as a result of construction and operation of the EAEC.

Soil And Groundwater Contamination

The materially recognized conditions identified in the Phase I ESA appear to be localized effects as a result of hazardous material handling practices associated with

previous agricultural activities. The area of localized contamination, at one of the residences on the overall 174-acre parcel, is not in the direct vicinity of where ground will be disturbed for construction of the EAEC. Therefore, no potential contamination impacts to soil and groundwater are expected to occur during the course of construction and operation of the EAEC as a result of existing materially recognized environmental conditions as identified in the Phase I ESA.

Hazardous materials used during construction will be stored within areas having secondary containment and/or cover. Hazardous materials used during operation will be stored primarily within covered areas, except for storage of calcium chloride, hydrogen and sulfuric acid, which are planned for storage outside. Secondary containment structures will be designed in accordance with Article 80 of the Uniform Fire Code, and will consist of reinforced concrete. Secondary containment in covered areas will be sized to store 100% of the volume of the contents in the primary tanks. Secondary containment in outside storage tanks exposed to storm water will be sized to also include the rainwater from a 25-year, 24-hour storm. Rain water and washdown water within hazardous material storage containment areas will be conveyed through an oil/water separator into the main plant sump, and pumped to the cooling tower basin where the water will be reclaimed for use as cooling tower makeup. No potential contamination impacts to soil and groundwater are expected to occur during the course of construction and operation of the EAEC as a result of hazardous material storage and use. (EAEC 2001p, Data Responses 70, 99 and 100)

Groundwater

The EAEC does not propose to use groundwater as a source of supply. The use of either fresh or recycled surface water will have no effect on groundwater supply. Therefore, groundwater supplies will not be depleted, and no impacts are anticipated.

Surface Water Hydrology

No streams or rivers will be altered as a result of the EAEC development, thus avoiding permitting under Sections 404 and 401 of the Clean Water Act. As part of the development of water supply to EAEC, a limited length of BBID's Canal 45 which is presently unlined would be lined with concrete. The lining would be installed within the canal, a man-made channel under dewatered conditions, and would not present an impact to water quality. Likewise, the proposed directional drilling under the Delta-Mendota Canal for the fresh water pipeline, would not cause an impact to water quality, as the construction method avoids disturbance to water and its quality within the canal. The EAEC site is not within the 100-year flood plain. The only project feature that approaches intersecting the 100-year flood plain is a portion of the proposed recycled waterline from MHCSD at Wicklund Road. The FEMA designated 100-year flood plain in the project vicinity occurs within approximately 2,000 feet of the south bank of Old River. Upon construction of the MHCSD wastewater treatment plant and the recycled waterline, the grade will be re-established so as to avoid any potential effects of flooding within the 100-year flood plain. The EAEC will not create any substantial new impoundment of water that could potentially cause flooding. Therefore, the EAEC is not considered to cause any negative impacts on surface water hydrology or flood routing. (EAEC 2001a, AFC Section 8.14.1)

Water Supply

BBID's Water Rights

Once acquired, an appropriative water right is maintained only by continuous beneficial use of the water. Regardless of the amount claimed in the original notice of appropriation or at the time diversion and use first began, the amount which can at any time be rightfully claimed under an appropriative right initiated prior to December 19, 1914, becomes fixed by actual beneficial use as to both amount and season of diversion. California Water Code Section 1202(b) defines unappropriated water as: "All water appropriated prior to December 19, 1914, which has not been in process, from the date of the initial act of appropriation, of being put, with due diligence in proportion to the magnitude of the work necessary to properly utilize it for the purpose of the appropriation, or which has not been put, or which has ceased to be put to some useful or beneficial purpose."

Defining amount and season of diversion can be accomplished by specifying water volumes or ranges of flow diverted by month. The conditions under which an appropriative water right can be forfeited in whole or in part include "due to nonuse." Nonuse means failure to put water to beneficial use for a period of years. The courts have held that Pre-1914 rights can be lost as the result of five years' nonuse *(Smith v. Hawkins* (1895) 110 Cal. 122). California Water Code Section 1241 states, "When the person entitled to the use of water fails to use beneficially all or any part of the water claimed by him, for which a right of use has vested, for the purpose for which it was appropriated or adjudicated, for a period of five years, such unused water may revert to the public and shall, if reverted, be regarded as unappropriated public water."

However, if a reduction of use is a result of a conservation effort, pursuant to any contract with any water user, that results in a reduced use of water by that person or agency, no forfeiture, dimunition, or impairment of the right to use the water conserved shall occur. Water conservation and reclamation projects include, but are not limited to, the following:

1. Projects for municipal and industrial advanced wastewater treatment to permit the reuse of the water for additional purposes;

2. Projects for the improvement of water supply and delivery facilities;

3. Projects for the improvement of on-farm irrigation systems which enable more efficient use of water; (Water Code §§ 11960 and 11962)

The Applicant has represented that BBID, through conservation and recent reductions in agricultural customer diversions, has reduced its water use from historic highs, and use by EAEC, combined with use by BBID's other customers, would be within historic patterns of use. (EAEC 2001a, AFC Section 8.14.2) At this time, staff has not been able to verify this claim.

In order to assess if the EAEC will create any significant change in the historic patterns of use, a summary of BBID's average monthly use of water over a 3-year period

between 1998 – 2000 (which is the limit of data available at this time), along with projections of initial fresh water use by EAEC is presented as follows:

Soils & Water Table 9
BBID's 1998 – 2000 Historic Average Monthly Water Demands with Projected Supply to EAEC (Acre-Feet)

Month	Byron Division Avg. Demand	Bethany Division Avg. Demand	**Subtotal – BBID Historic Demands**	Initial Supply To EAEC (2004)	**Total - BBID Projected Demands with EAEC (2004)**
January	100	10	**110**	306	**416**
February	0	0	**0**	276	**276**
March	160	50	**210**	306	**516**
April	1,000	700	**1,700**	296	**1,996**
May	2,700	1,700	**4,400**	306	**4,706**
June	3,700	3,300	**7,000**	545	**7,545**
July	3,200	3,600	**6,800**	563	**7,363**
August	2,100	3,700	**5,800**	563	**6,363**
September	1,300	1,600	**2,900**	545	**3,445**
October	400	300	**700**	306	**1,006**
November	0	0	**0**	296	**296**
December	0	0	**0**	306	**306**
Total	14,660	14,960	**29,620**	4,614	**34,234**

In reference to BBID's historic demands, it appears that water supply to EAEC could change BBID's existing and historical patterns of water use, particularly during the months of November – February each winter. In addition, the AFC indicates BBID's normal maintenance schedule for their canals requires them to be shut down from November through March for cleaning of aquatic weeds and canal bank reshaping, further suggesting that year-round water supply to the EAEC may create a change in season of use compared to historical patterns. Staff requested additional historical monthly data from the SWRCB, but it was not available, apparently because BBID has not filed any Statements of Water Diversion and Use with the SWRCB. (EAEC 2001c and EAEC 2001a) & (AFC Page 7-2, Sec. 7.0, and Section 7.1.6)

During 2000, BBID served approximately 31,000 acre-feet to its agricultural customers, and 700 acre-feet to its industrial customers, for a total supply of 31,700 acre-feet for the year. A summary of BBID's projected average annual demands is as follows:

Soils & Water Table 10
BBID's Projected Average Annual Water Demands (Acre-Feet)

Demand Type	2000	2010	2020	2030	2040
Agricultural Use	**31,000**	**34,300**	**31,400**	**28,500**	**25,600**
Municipal & Industrial Use					
Discovery Bay West	-	500	500	500	500
Unimin Industrial Use	700	1,500	1,500	1,500	1,500
Mountain House (RWSA 1)	-	4,641	9,415	9,415	9,415
Tracy Hills (RWSA 2)	-	6,000	6,000	6,000	6,000
East County Airport	-	1,100	1,200	1,200	1,300
Byron	-	500	600	700	700
East Altamont Energy Center	**-**	**2,790**	**1,716**	**1,716**	**1,716**
Subtotal – Municipal & Industrial Use	**700**	**17,031**	**20,931**	**21,031**	**21,131**
Total – Agric. , Muni. & Indus. Use	**31,700**	**51,331**	**52,331**	**49,531**	**46,731**

Source: (EAEC 2001a, AFC Section 7.1)
Note: For EAEC, fresh water supplies are reduced according to projections of available recycled water from MHCSD;

BBID's projected demands suggest not only an increase in the annual quantity of water to be used, but also a significant increase in municipal and industrial customers compared to serving primarily agricultural customers historically. This could lead to a change in seasonal quantities of use, with greater year-round use of water supply. While these potential changes in quantities and season of use may call to question whether BBID is entitled to serve EAEC under existing entitlements of its Pre-1914 Appropriative water rights, staff is focusing its assessment on any potential environmental impacts or potential injury to other water users that could result from the proposed water supply to EAEC. DWR has advised staff that it may protest BBID's plans to supply EAEC with fresh water considering the apparent change that would be caused in BBID's quantity and season of use of its diversions.

In the AFC, the applicant contends that if BBID increases their diversion from the Delta, DWR would have to decrease their diversions for the SWP by a similar amount. At the data request workshop, BBID confirmed this. However, DWR has expressed that its beneficial uses under the SWP, or other Delta beneficial uses including maintenance of plantlife, fish and wildlife, could be injured as a result of this increased diversion by BBID. (CEC 2001i, page 1) DWR is responsible for maintaining Delta water quality consistent with the initiatives developed under CalFed, particularly during the most critical period of summer as typically occurs between late June through early September. During this period, Delta flows are largely augmented by releases from storage as developed by the CVP, SWP and other entities. BBID's entitlements are limited to diversions of natural flow, with no entitlements to water developed by storage. As an illustration of the potential for change in BBID's diversions as a result of serving EAEC, the project area of approximately 40 acres would demand about 3 acre-feet/acre/year for continued agricultural use, or a total of about 120 acre-feet/year. In comparison, EAEC will demand on average 4,616 acre-feet/year, and on peak up to

7,000 acre-feet/year, which equates to water use of about 115 acre-feet/acre/year on average, and 175 acre-feet/acre/year on peak to serve EAEC. The incremental increase in water use resulting from a change in land use from agricultural to industrial as proposed by the Applicant for EAEC, could result in a reduction of water available for DWR's customers or for maintaining Delta water quality, on the order of about 4,500 acre-feet/year on average or 6,880 acre-feet/year on peak. This range of potential incremental increase in BBID's water diversions could be considered within the range of allocations for some of DWR's customers of the SWP. Therefore, if water available to DWR was diminished within this range, the impact could be equivalent to depriving one of DWR's customers of nearly the entirety of its normal water supply.

At this time, the potential for significant environmental impacts or injury to other water users has not been fully determined. Staff is awaiting additional information from DWR regarding their intent to protest any increase in BBID diversion and or possible changes in the operation of the SWP in the event that BBID serves the proposed project. Staff is also awaiting additional information from the Applicant relative to previous Bay-Delta analyses and the relationship of BBID's water entitlements to those of the SWP and CVP, in order to more fully evaluate the potential impacts from the proposed water supply to EAEC. In addition, staff is requesting the Applicant provide monthly diversion data from BBID over a 20–year period, rather than average data over the most recent 3 years, and a summary of conservation measures employed by BBID that supports the Applicant's representation that BBID has retained its historic entitlements, and not potentially lost some portion due to non-use.

Recycled Water From MHCSD

The Applicant is proposing to use a source of recycled water supply to be served by BBID, currently under development by Mountain House Community Services District (MHCSD). Although the supply from MHCSD would be the closest source to EAEC, its potential for supply is limited to serving up to 62% of the total water supply needs of EAEC (average annual basis), and it will require about 20 years to reach its maximum potential. Until such time as these resources are available, the applicant proposes to rely on fresh surface water resources from the Delta.

Possible Alternatives to the Proposed Water Supply

The analysis of potential impacts to water resources requires consideration of several alternative water supplies linked with wet cooling technology, along with consideration of dry cooling technology. The following assessment evaluates environmental and cost characteristics of five project alternative configurations integrating water supplies and cooling technologies, which are mutually dependent.

In addition to the opportunity for obtaining recycled water supply from MHCSD, there may also be the opportunity to obtain recycled supply from the Discovery Bay Community Services District (DBCSD) and the City of Tracy, or to significantly reduce project water demands by changing to wet/dry or dry cooling. The comparison of alternatives is complex, as each alternative provides a range of value and also limitations, depending on the measure. The standard for comparison of fresh and recycled water supplies is specified under Section 13550 of the Water Code, which is reproduced in part as follows:

"The Legislature hereby finds and declares that the use of potable domestic water for nonpotable uses, including but not limited to … industrial … uses, is a waste or an unreasonable use of the water within the meaning of Section 2 of Article X of the California Constitution if recycled water is available which meets all of the following conditions … :

1) The source of recycled water is of adequate quality for these uses and is available for these uses. …

2) The recycled water may be furnished for these uses at a reasonable cost to the user. (In determining reasonable cost, the State Board shall consider all relevant factors, including, but not limited to, the present and projected costs of supplying, delivering and treating potable domestic water for these uses and the present and projected costs of supplying and delivering recycled water for these uses, and shall find that the cost of supplying the treated recycled water is comparable to, or less than, the cost of supplying potable domestic water.)

3) After concurrence with the State Department of Health Services, the use of recycled water from the proposed source will not be detrimental to public health.

4) The use of recycled water for these uses will not adversely affect downstream water rights, will not degrade water quality, and is determined not to be injurious to plantlife, fish, and wildlife. "

The detailed analysis comparing fresh versus recycled water supplies and dry cooling is as shown in Appendix B. The analysis considers five alternatives described as follows:

Alternative 1 (Proposed Project) – Wet Cooling using BBID's fresh water supply augmented by MHCSD's recycled water supply; BBID would supply initially (in 2004) all 4,600 acre-feet/year from fresh water. By 2020, BBID's fresh water supply would provide 1,716 acre-feet/year (38%), and MHCSD's recycled water supply would provide 2,884 acre-feet/year (62%), assuming full build-out of MHCSD.

Alternative 2 – Wet cooling using Discovery Bay Community Service District's (DBCSD's) recycled water supply and BBID's fresh water supply; DBCSD would supply about 2,352 acre-feet/year (51%) recycled water and BBID would supply about 2,248 acre-feet/year (49%) fresh water.

Alternative 3 – Wet Cooling using MHCSD's and Discovery Bay Community Service District's (DBCSD's) recycled water supplies; This alternative still requires some limited supply of fresh water from BBID (up to 2,084 acre-feet/year in 2004/2005) during initial years of EAEC operation, and diminishing to zero by about 2012. MHCSD and DBCSD would provide recycled water supply for all 4,600 acre-feet/year (100%) of project non-potable water needs by about 2012.

Alternative 4 – Wet cooling using City of Tracy's recycled water supply; City of Tracy would supply all 4,600 acre-feet/year (100%) of project non-potable water needs beginning in 2004.

Alternative 5 – Dry cooling using BBID's fresh water supply, reducing non-potable water demands from 4,600 to 83 acre-feet/year;

A comparison of wet vs. wet/dry vs. dry cooling for the EAEC is summarized as follows:

Soils and Water Table 11
Comparison of Cooling Tower Environmental & Performance Characteristics

Environmental Impact	Wet Cooling	Wet/Dry Cooling	Dry Cooling
WATER REQUIREMENT	High fresh water supply and treatment requirements (4,600 AF/year)	Proportional to percentage of wet to dry ratio	None for Cooling (83 AF/year, primarily for steam production)
Water Discharge	High discharge and treatment requirements	Intermediate discharge and treatment requirements	None
Plant Efficiency/Fuel Supply	Baseline	Intermediate plant efficiency or higher fuel demand	Lower plant efficiency or higher fuel demand (Up to a 4% reduction in capacity, or 46 MW)
Plant Emissions	Baseline	Higher than wet system for same output	Highest for same output
Auxiliary Power Requirements	Some from fans and pumping	Greater than wet due to additional fans	Greatest compared to wet and wet/dry
Secondary Emissions – cooling tower drift	Some salt deposition from Cooling Tower drift	Less salt deposition from Cooling Tower drift	No salt deposition or secondary emissions
Land Requirements	Least of cooling tower alternatives (4 acres)	Moderately more than wet	Moderately more than wet and wet/dry (5 acres)
Visual Impact -Structural	Least of cooling tower alternatives (1,027' long, 54' wide, 43' high)	Taller and larger structure compared to wet	Taller and larger structure compared to wet and wet/dry (661' long, 207' wide, 120' high)
Visual Impact -Plume	Visible plume, function of ambient temperatures	Plume occurrence can be reduced or eliminated	No plume
Noise	Least of cooling tower alternatives	Can be higher than wet	Can be higher than wet and wet/dry (65 – 70 dBA @ 400')

The application of either a dry air-cooled condenser or wet/dry cooling tower system is highly feasible and can eliminate or reduce the use of water for the EAEC cooling system from that required by the wet evaporative cooling system proposed. (EAEC 2001t, Response to Data Request #84)

Results of the analysis comparing capital and operating costs on a relative basis for Alternatives 1 through 5 are summarized as follows:

Soils and Water Table 12
Water Supply/Cooling Alternatives - Comparison of Capital & Operating Costs

Cost Component	Alt. 1	**Alt. 2**	**Alt. 3**	**Alt. 4**	**Alt. 5**
	MHCSD & BBID	**DBCSD & BBID**	**MHCSD & DBCSD**	**City of Tracy**	**Dry Cooling, BBID**
Tertiary Treatment of Source Water	$0	$5,000,000	$5,000,000	$1,400,000	$0
	(24" Dia, 2.1 Miles)	(24" Dia, 2.1 Miles)	(24" Dia, 2.1 Miles)	(24" Dia, 2.1 Miles)	(12" Dia, 2.1 Miles)
Water Conveyance - Fresh Water	$6,000,000	$6,000,000	$6,000,000	$6,000,000	$3,500,000
	(24" Dia, 4.6 Miles)	(24" Dia, 7 Miles)	(24" Dia, 11.6 Miles)	(24" Dia, 10 Miles)	
Water Conveyance - Recycled Water	$8,000,000	$12,000,000	$20,000,000	$17,200,000	$0
EAEC Water Treatment	$9,863,000	$9,863,000	$9,863,000	$9,863,000	$9,863,000
EAEC Water Treatment Additions or Savings	$0	$1,308,000	$1,308,000	$1,308,000	($4,000,000)
Annual EAEC Water Treatment Operations	$1,109,000	*$1,580,000*	*$1,580,000*	$1,580,000	$200,000
Pres. Value of Annual Water Treatment Op's	$14,724,941	$20,978,725	$20,978,725	$20,978,725	$2,655,535
	(1716 AF x $60/AF)	(2248 x $60/AF)	(2884 x $48/AF)		(83 AF x $60/AF)
Annual Water Purchase Cost - Fresh	$103,000	$135,000	$138,000	$0	$5,000
Pres. Value of Annual Water Purch's	$1,367,600	$1,792,486	$1,832,319	$0	$66,388
	(2884 AF x $48/AF)	(2352 x $48/AF)	(2352 AF x $48/AF)	(4600 AF x *$48/AF)*	
Annual Water Purchase Cost - Recycled	$138,000	$113,000	$113,000	$221,000	$0
Pres. Value of Annual Water Purch's	$1,832,319	$1,500,377	$1,500,377	$2,934,366	$0
Wet Cooling Tower	$48,200,000	$48,200,000	$48,200,000	$48,200,000	$0
Annual Wet Cooling Operating Costs	$1,440,000	$1,440,000	$1,440,000	$1,440,000	$0
Present Value of Wet Cooling Op's	$19,119,851	$19,119,851	$19,119,851	$19,119,851	$0
Dry Cooling Tower	$0	$0	$0	$0	$83,200,000
Annual Dry Cooling Operating Costs	$0	$0	$0	$0	$246,000
Present Value of Dry Cooling Op's	$0	$0	$0	$0	$3,266,308
Subtotal - All Capital Costs	**$72,063,000**	**$82,371,000**	**$90,371,000**	**$83,971,000**	**$92,563,000**
PV of All Costs (2001 $, 7%, 30 Years)	**$109,107,711**	**$125,762,439**	**$133,802,272**	**$127,003,942**	**$98,551,231**

Note 1: Annual lost power generation associated with Alt. 5 - Dry Cooling is estimated to average 26 MW x 3,000 Hours/Year = 78,000 MWH/Year,
Note 2: Costs used in this analysis are primarily the cost data supplied by the Applicant (EAEC 2001t, Response to Data Request #84)
Note 3: The cost of Water Conveyance – Fresh Water is included in Alt. 4 as a backup to recycled water in lieu of developing on-site recycled water storage;

Indirect impacts

In the event that SWP supplies must be cut back to accommodate an increase in BBID diversions to serve EAEC, current users of SWP resources could be potentially indirectly affected. It is difficult to assess the environmental consequences of a decrease in SWP service to current customers, but staff has evaluated some potential

worse case economic impacts that could result. As an indirect cost impact, consideration could also be given to the cost of replacing fresh water supplies for other customers to the extent this fresh water would be used for cooling purposes of the EAEC, as the opportunity for retaining the equivalent fresh water quantities for potable supplies elsewhere in the state would be lost. Considering environmental limitations in developing new water supplies in the state, and recognizing fresh water supplies in southern California can exceed $1,000/acre-foot, a value of $1,000/acre-foot was used to estimate its value. Although the proper analysis would be to account for the actual development costs of a new water supply or the cost to implement conservation, actual cost data is scarce because new supplies are also scarce. Although the use of an actual purchase price of $1,000/acre-foot most likely underestimates (environmentally and economically) the cost to replace a fresh water supply that could be dedicated for potable use, but may instead be committed to industrial use, staff believes that the rate provides a relative and conservative estimate of water replacement costs for the alternatives.

Soils and Water Table 13
Cost to Replace Fresh Water Supplies

Cost Component	**Alt. 1**	Alt. 2	Alt. 3	Alt. 4	Alt. 5
	MHCSD & BBID	**DBCSD & BBID**	**MHCSD & DBCSD**	**City of Tracy**	**Dry Cooling, BBID**
	(1716 AF x $1,000/AF)	(2248 AF x $1,000/AF)			(83 AF x $1000/AF)
Annual Fresh Water Value @ $1,000/AF	$1,716,000	$2,248,000	$0	$0	$83,000
Present Value of Fresh Water	$22,784,489	$29,848,211	$0	$0	$1,102,047

Relative replacement costs of fresh water supplies would be zero under Alternatives 3 and 4, which provide 100% recycled water to EAEC ultimately, with Alternative 5 – Dry Cooling being the next lowest cost at $1.1 million. Alternative 1 consisting of the proposed project would cause replacement costs on the order of $23 million, while Alternative 2 would result in the highest replacement costs of approximately $30 million.

Results of the overall analysis comparing various water supply and cooling alternatives in terms of environmental and cost considerations, are summarized as follows:

Soils and Water Table14
Summary of the Water Supply and Cooling Alternatives

Issue or Measure	Alt. 1	Alt. 2	Alt. 3	Alt. 4	Alt. 5
	Wet Cooling & MHCSD & BBID Water Supplies	Wet Cooling & DBCSD & BBID Water Supplies	Wet Cooling & MHCSD, DBCSD & BBID Water Supplies	Wet Cooling & City of Tracy Water Supply	Dry Cooling & BBID Water Supply
Potential Conflict with Water Rights	Yes	Yes	Yes	No	No
Potential Loss of Fresh Water Supplies	Yes	Yes	Yes	No	No
Ultimate Dependency On Fresh Water (Acre-Feet)	1,716	2,248	2,084 – 0 by 2015	0	83
Water Quality before Treatment (TDS in mg/l)	573	748	1,000	1,020	174
Potential Reduction in Delta Flows by EAEC Utilization of Wastewater (AF/Year & mgd)	0 AF/yr 0 mgd	2,016 AF/yr 1.8 mgd	2,016 AF/yr 1.8 mgd	4,600 AF/yr 4.1 mgd	0 AF/yr 0 mgd
Capital Costs for Water Supply & Cooling	$72 MM	$82 MM	$90 MM	$84 MM	$93 MM
PV of Capital and Operating Costs	$109 MM	$126 MM	$134 MM	$127 MM	$99 MM

Note: Shaded boxes denote the most favorable characteristic of each measure.

As a result of this analysis of alternatives and based on information available at this time, it appears that Alternative 5 – Dry Cooling with limited water supply from BBID (83 acre-feet/year) is the only alternative that would avoid potentially significant adverse impacts to water resources. DWR and BBID are in dispute as to recognition of their respective water rights. In relation to the proposed EAEC, and in the event that BBID's entitlement to winter time diversions were challenged and found invalid as a result of a decision within the judicial system, BBID would still be left with remedies for obtaining such entitlement including seeking to appropriate additional water rights (which likely would take years to process), or by securing a contractual entitlement for winter diversions of water from others such as the SWP. It is also important to note that BBID is currently in negotiations with DWR seeking to obtain recognition of their Pre-1914 Water Right entitlements with respect to supplying future municipal and industrial customers in comparison to SWP entitlements for diversion of water and flows needed for meeting Delta water quality standards.

The potential for incurring adverse water resource impacts appears under Alternative 1 with respect to fresh water, and Alternatives 2, 3 and 4 with respect to recycled water, whereby each of these would reduce flows in the Delta, potentially injuring other

beneficial uses, including the maintenance of flows and habitat needed to protect fish and wildlife. While DWR has indicated that it may protest BBID's diversions of fresh water to supply EAEC, the magnitude of reduction in Delta flows attributable to reclaiming treated wastewater currently discharged to the Delta by DBCSD and City of Tracy is similar. Although, DBCSD and City of Tracy could submit a Petition for Change with the SWRCB for a reduction in their existing wastewater discharges to Old River and the Delta, one of the tests for consideration by the SWRCB is if any legal user of the discharged treated wastewater will be affected. Because both of these treated wastewater discharges into Old River commingle with other waters of the state in the vicinity of diversions for the SWP, CVP and other users, which are supplied by flows partially from Old River, staff anticipates that the effects of reducing Delta flows from reclaiming treated wastewater would be similar to increasing BBID's fresh water diversions, and would therefore lead to a similar impact.

While under Alternative 5 – Dry Cooling, the initial capital investment of $93 million for water supply and cooling facilities is higher than the other alternatives ranging from $72 million to $90 million, when accounting for annual operating costs for water purchases, wastewater treatment chemicals and cooling tower chemicals, the total relative cost of Dry Cooling is less that the other alternatives when considered over the 30-year project life. In comparison, Dry Cooling has a total relative cost of $99 million, versus a range of $109 million to $134 million for the other alternatives.

Although peaking capacity would be limited by using Dry Cooling, estimated to be reduced by 7.5 MW (0.7%) on an average temperature day, to 46.4 MW (4.2%) on a hot day, these limitations do not appear significant considering the overall plant capacity of 1,100 MW. Dry and Wet/Dry cooling systems are well tested and in many power plants, some states have exclusively required Dry Cooling for all new power plants. One can consider that the impact resulting in loss of production (efficiency) may be countered by the benefit from using less of California's increasingly scarce and valuable fresh water supplies. DWR projects that if current trends continue, the state's water demands are expected to exceed supply by 2020. (CA Water Plan Update, Bulletin 160-98)

Based on the analysis of water supply and cooling alternatives, and the apparent potential to cause adverse impacts to the environment or injury to other water users, staff cannot conclude at this time that the proposed project would avoid causing significant adverse impacts with regard to water supply.

Process Wastewater

As proposed, the EAEC will be implementing a zero liquid-discharge system, which effectively treats and recycles all process wastewater streams for reuse within the plant. The primary waste product of the zero liquid-discharge system is a salt cake, considered a solid and not a liquid waste, which will be hauled by truck for disposal in landfill. The Applicant has estimated that generation of salt cake for disposal in landfill will average approximately 3.5 tons/day if using 100% BBID raw water, and 10.3 tons/day if using the proposed blend of raw and recycled water.
Sanitary wastewater will be processed using a septic tank and leach field. Because of the potential for groundwater to be near the ground surface in the vicinity of the EAEC, the leach field will be constructed according to an above ground mound-type design.

The mound system will be designed to the requirement of EPA's Design Manual for Onsite Wastewater Treatment and Disposal Systems (EPA No. 625/1-80-012), where it is referred to as the "NoDak" disposal system. In order to develop the NoDak disposal system, the Applicant will need to obtain a disposal permit from Alameda County Environmental Health Department. If the existing ordinances are not changed to accommodate the NoDak disposal system, the Applicant will need to obtain a variance to construct and operate the system. (EAEC 2001p, Data Responses 96 and 97)

Storm water

In order to compare pre and post-project storm water runoff under the change in site ground conditions, runoff is calculated for 23.7 acres of the site, representative of the non-process portion of area for EAEC. The non-process area, consisting of the portion of grounds where no hazardous materials are handled or stored, will discharge its storm water off-site. The calculated pre and post-project storm water runoff is summarized as follows:

Soils and Water Table 15
Comparison of Pre & Post-Project Storm Water Discharge

Return Period of Storm (Years)	Rainfall for 24-hour Storm (Inches)	Total Pre-Project Discharge from Site (Millions of Gallons	Total Post-Project Discharge from Site (Millions of Gallons)
10	2.9	0.746	
25	3.2	0.824	
50	3.8	0.978	
100	3.9	1.004	

(EAEC 2001a, AFC Section 8.14) and (To be Provided by Applicant)

Drainage at the EAEC site has been designed to prevent flooding of permanent facilities and roads, both onsite and offsite, and to maintain storm water flows at or below pre-project flows.

Storm water developed over the 40 acres for the EAEC generation facilities will be managed separately between process (where hazardous materials are handled or stored on-site) and non-process areas. Open process areas will be curbed to contain the maximum 25-year, 24-hour design storm runoff in addition to the volume of the largest storage container. Storm water drainage will be conveyed to an oil/water separator, and then into the cooling tower basin. The system of individual containments and the routing of process area storm water to the cooling tower basin, will serve to maintain storm water flows incrementally below pre-project levels.

Storm water from non-process areas will be conveyed through an oil/water separator into the storm water detention pond. The storm water detention pond will serve to detain runoff, and discharge at flows no greater than pre-project conditions. Discharge will pass into the existing drainage channel along the eastern boundary of the EAEC site, which flows northerly into the intake channel of the Delta-Mendota Canal. The storm water facilities will be sized to accept the 25-year, 24-hour design storm runoff consistent with the criteria specified by the Alameda County Flood Control and Water

Conservation District's criteria for sizing storm water facilities. Storm water will be managed in accordance with the Storm Water Pollution Prevention Plans (SWPPP's) prepared for construction and industrial activities, under the General NPDES Permit for Discharges of Storm Water Associated with Construction and Industrial Activity respectively. These NPDES Permits will be administered by the Central Valley – Sacramento Office of the RWQCB.

Although the Applicant has represented that post-project discharges of storm water will be less than pre-project discharges in every case, staff has requested the Applicant to supply results of its calculations of post-project storm water flows in order to verify adequate sizing of facilities including the detention pond. Staff's assessment of impacts from storm water are pending submittal by the Applicant of the results of its post-project calculations of runoff and discharge.

CUMULATIVE IMPACTS

In addition to EAEC's proposed use of fresh water originating from the Delta, two other AFC proceedings are in progress, that are proposing to use fresh water supply from the Delta. These are summarized as follows:

Soils and Water Table 16
Cumulative Diversions of Delta Water Resources According to AFC's

Project Name	AFC Proceeding #	Annual Average Quantity of Water (Acre-Feet/Year)
East Altamont Energy Center	01-AFC-04	4,616
Tesla Power Plant	01-AFC-20	5,100
Tracy Peaker Project	01-AFC-16	30
Total		**9,746**

Considering that the effects of the proposed diversion by BBID for supply to the EAEC are considered potentially injurious to the SWP, Delta, and other water users, the cumulative impact of EAEC's proposed water supply with others currently proposed can be considered significant to the extent that EAEC's impact is independently significant.

Staff is guarded in its assessment to determine that the additional effects on Delta water resources would accumulate as a result of other currently proposed projects, as the most significant project, Tesla Power Plant, has only recently been submitted before the Commission, and its effects have not yet been determined. According to information available in the Tesla Power Plant AFC, it appears that water diverted for supply to Tesla from the California Aqueduct will be in exchange for groundwater that has been banked by a local water supplier. Therefore, there would be no additional diversions of Delta water resources for supply to Tesla Power Plant, but instead there would be increases in groundwater withdrawal. The indirect impacts of additional groundwater withdrawal are subject to assessment under the Tesla AFC proceeding.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the minority population is less than fifty percent within a six-mile radius of the proposed EAEC project (please refer to Socioeconomics Figure 1 in this Staff Analysis), and Census 1990 information that shows the minority/low income population is less than fifty percent within the same radius. However, there is a pocket of minority persons within six miles that staff has considered for impacts. Based on the Soils and Water analysis, staff cannot conclude at this time that the proposed project would not cause significant adverse impacts with regard to water supply resulting from the operation of the project, regarding the population, and therefore staff cannot currently conclude that there are no Soils and Water environmental justice issues related to this project. Please refer to the Conclusions section for staff's plans to further investigate this matter.

FACILITY CLOSURE

The EAEC is expected to operate for a minimum of 30 years. Closure options range from "mothballing," with the intent of a restart at some time, to the removal of all equipment and facilities.

The decommissioning plan will be submitted to the Energy Commission for approval prior to decommissioning. Compliance with all applicable LORS, and any local and/or regional plans will be required. The plan will address all concerns in regard to potential erosion and impacts on water quality.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

AGENCY COMMENTS

Alameda County

On October 4, 2001, Staff received a letter from Alameda County that provided comments from various County departments regarding the proposed EAEC. This letter contained several recommended conditions of certifications. Staff is reviewing and considering these recommended conditions and will work with the county to address their concerns, potentially incorporating several of these conditions in the FSA.

Byron Bethany Irrigation District

In its October 8, 2001 letter to Ms. Cheri Davis, the Byron Bethany Irrigation District expressed the following concerns with regard to several Reports of Conversation prepared by staff. BBID's issues and staff's responses are summarized as follows:

1. *Staff did not appear to recognize that among BBID's water supplied for irrigation purposes, it also supplies water for municipal and industrial purposes.*

   Response: Staff recognizes the one existing industrial customer, Unimin, an aggregate processing supplier, is served by BBID.

2. *BBID will not readily agree to an independent purveyor expanding into BBID's service area providing water service that BBID is currently developing.*

   Response: Alternatives sources of recycled water supply are being investigated because BBID's proposed recycled water supply from MHCSD to EAEC is not adequate to serve the full needs of EAEC, and is ultimately projected to only supply 62% of EAEC's demands by 2020.

3. *BBID states that if an independent purveyor of recycled water should extend water service into the service area of BBID, such action would constitute a taking of property, requiring just compensation, including lost revenues.*

   Response: Although BBID cannot offer EAEC a sufficient supply of recycled water either initially or ultimately to meet all of EAEC's needs, staff notes BBID's position is an interpretation of law, for which opposing views have been expressed by the SWRCB and City of Tracy. If this should be an issue in the ultimate water supply scheme for EAEC, staff will further explore this issue.

4. *BBID states that as part of the consideration of any alternative supplies of recycled water to EAEC, that it must be available to the user, and furnished at a reasonable cost to the user in accordance with Water Code § 13550(a)(2).*

   Response: Staff recognizes the reference to Water Code § 13550(a)(2), and its conditions, and includes such discussion as part of its analysis. As for the availability of alternate supplies of recycled water to EAEC, staff has simply inquired informally with other local potential suppliers as to their interest to supply recycled water to EAEC in order to evaluate alternatives (including consideration of costs) to the proposed water supply.

5. *BBID states that it is erroneous to conclude that providing potable domestic water to EAEC is an unreasonable use of water within the meaning of Section 2 of Article X of the California Constitution.*

   Response: Staff did not form this conclusion. The September 12, 2001 Report of Conversation to which BBID refers, presents a discussion about a hypothetical situation in reference to LORS, and not a conclusion. (CEC 2001f, page 1)

6. *BBID states that the Energy Commission must determine if use of any source of recycled water would result in the loss or diminution of existing water rights.*

   Response: Staff has included this consideration as part of its discussion under Analysis of Project Related Impacts. See Soils and Water Table 13, and Soils and Water Appendix B.

7. *BBID notes that currently the City of Tracy does not physically have recycled water available to meet the needs of EAEC, observing that the City of Tracy's supply is dependent on expansion of its treatment plant, and that its availability is speculative.*

   Response: As stated in the September 13, 2001 Report of Conversation between staff and the City of Tracy, the City of Tracy is planning both capacity as well as

treatment upgrades to meet Title 22 tertiary standards, over the next 3-4 years. Existing production in the City of Tracy's wastewater plant is almost double the supply needed by EAEC, requiring only a change in the level of treatment. The level of treatment would need to be improved from secondary to tertiary, with possibly an additional upgrade in the disinfection process to allow unrestricted use of reclaimed water for industrial uses. The City also characterized the likelihood of implementing their wastewater treatment plant upgrades for tertiary treatment as having a 95% probability due to state-level political, regulatory and financial support. The City has been allocated an $8.5 million grant from Proposition 13 funds (AB 1584, signed by the governor on October 7, 1999), and is scheduled to issue its Draft Environmental Impact Report for consideration under CEQA of its wastewater treatment upgrade plans by end of this year. While the availability of tertiary-treated water from the City of Tracy is not 100% certain, it appears to be a viable alternative to consider for recycled water supply to EAEC.

PUBLIC COMMENTS

G&DK-4 - *Mr. And Mrs. Gary Kuhn expressed concern regarding the two evaporation ponds as initially proposed for the EAEC.*

The Applicant has since withdrawn the evaporation ponds from its plans, and instead proposes to implement a zero liquid discharge system, which will avoid any open storage or discharge of process wastewater. Instead, all process wastewater will be treated on-site and reused, and a solid waste salt cake will be hauled off-site for landfill disposal.

CONCLUSIONS

Based on the analysis of water supply and cooling alternatives, and the apparent potential to cause adverse impacts to the environment or injury to other water users, staff cannot conclude at this time that the proposed project would not cause significant adverse impacts with regard to water supply.The proposed project could lead to significant adverse impacts as a result of relying on BBID to divert fresh water from the Delta for EAEC during seasons and in quantities uncharacteristic of BBID's historic patterns of diversion.The project as proposed, may not comply with LORS from the standpoint of § 1202(b) of the California Water Code, in that the proposed season and quantities of diversion to supply EAEC may not rely entirely on BBIDs entitlements for appropriated water.DWR has expressed concern that its beneficial uses under the SWP, or other Delta beneficial uses including maintenance of plantlife, fish and wildlife, could be injured.(CEC 2001i, page 1) Staff is awaiting additional information from DWR and the Applicant relative to previous Bay-Delta analyses and the relationship of BBID's water entitlements to those of the SWP and CVP, in order to more fully evaluate the potential impacts from the proposed water supply to EAEC. In addition, staff is requesting the Applicant provide monthly diversion data from BBID over a 20–year period, rather than average data over the most recent 3 years, and a summary of conservation measures employed by BBID that supports the Applicant's representation that BBID has retained its historic entitlements, and not potentially lost some portion due to non-use.

PROPOSED CONDITIONS OF CERTIFICATION

The following conditions have been developed for the project:

SOIL & WATER 1: Prior to beginning any site mobilization activities, the project owner shall obtain staff approval for a final Erosion Control Plan that addresses all project elements. The final plan to be submitted for staff's approval shall contain all the elements of the draft plan, with changes made to address any staff comments and the final design of the project.

Verification: The Erosion Control Plan shall be submitted to the CPM at least sixty days prior to start of any site mobilization activities. Approval of the final plan by the CPM must be received prior to the initiation of any site mobilization activities.

SOIL & WATER 2: The project owner shall submit a Notice of Intent for construction under the General NPDES Permit for Discharges of Storm Water Associated with Construction Activity to the State Water Resources Control Board (SWRCB), and obtain CEC Staff approval of the related Storm Water Pollution Prevention Plan (SWPPP) for Construction Activity. The SWPPP will include final construction drainage design and specify BMP's for all on and off-site EAEC project facilities. This includes final site drainage plans and locations of BMP's.

Verification: At least 30 days prior to the start of any site mobilization activities, the SWPPP for Construction Activity and a copy of the Notice of Intent for construction under the General NPDES Permit for Discharges of Storm Water Associated with Construction Activity filed with the SWRCB, shall be submitted to the CPM. Approval of the final plan by the CPM must be received prior to initiation of any site mobilization activities.

SOIL & WATER 3: The project owner shall submit a Notice of Intent for operating under the General NPDES Permit for Discharges of Storm Water Associated with Industrial Activity to the State Water Resources Control Board (SWRCB), and obtain CEC Staff approval of the related Storm Water Pollution Prevention Plan (SWPPP) for Industrial Activity. The SWPPP will include final operating drainage design and specify BMP's and monitoring requirements for the EAEC project facilities. This includes final site drainage plans and locations of BMP's.

Verification: At least 30 days prior to the start of project operation, the SWPPP for Industrial Activity and a copy of the Notice of Intent for operating under the General NPDES Permit for Discharges of Storm Water Associated with Industrial Activity filed with the SWRCB, shall be submitted to the CPM. Approval of the final plan by the CPM must be received prior to initiation of project operation.

SOIL & WATER 4: The project owner will install metering devices and record on a monthly basis the amount of recycled and fresh water used by the project. The

project owner shall prepare an annual summary which will include the monthly range and monthly average of daily usage in gallons per day, and total water used by the project on a monthly and annual basis in acre-feet. For subsequent years, the annual summary will also include the yearly range and yearly average water use by the project. This information will be supplied to the CPM.

Verification: The project owner will submit as part of its annual compliance report a water use summary to the CPM on an annual basis for the life of the project. Any significant changes in the water supply for the project during construction or operation of the plant shall be noticed in writing to the CPM at least 60 days prior to the effective date of the proposed change.

SOIL & WATER 5: The project owner shall provide the CPM with a request for a Grading Permit consistent with the requirements of Alameda County Public Works Agency, and evidence of having obtained the permit prior to construction.

Verification: Thirty (30) days prior to start of construction, the project owner shall submit to the CPM a request for a Grading Permit consistent with the requirements of Alameda County Public Works Agency, and evidence of having obtained the permit prior to construction.

SOIL & WATER 6: The project owner shall provide the CPM with a request for a Waste Disposal Permit for its proposed disposal of sanitary waste in a septic system, consistent with the requirements of Alameda County Environmental Health Department, and evidence of having obtained the permit prior to construction.

Verification: Thirty (30) days prior to start of construction, the project owner shall submit to the CPM a request for a Waste Disposal Permit consistent with the requirements of Alameda County Environmental Health Department, and evidence of having obtained the permit prior to construction.

SOIL & WATER 7: The project owner shall provide the CPM with a request for a Grading Permit applicable to the proposed fresh water pipeline, consistent with the requirements of Contra Costa County Public Works Department, and evidence of having obtained the permit prior to construction.

Verification: Thirty (30) days prior to start of construction, the project owner shall submit to the CPM a request for a Grading Permit consistent with the requirements of Contra Costa County Public Works Department, and evidence of having obtained the permit prior to construction.

SOIL & WATER 8: The project owner shall provide the CPM with a request for a Building Permit applicable to the proposed Fresh Water Pump Station located at BBID's Canal 45, consistent with the requirements of Contra Costa County Public Works Department, and evidence of having obtained the permit prior to construction.

Verification: Thirty (30) days prior to start of construction, the project owner shall submit to the CPM a request for a Building Permit consistent with the requirements of Contra Costa County Public Works Department, and evidence of having obtained the permit prior to construction.

SOIL & WATER 9: The project owner shall provide the CPM with a request for a Grading Permit applicable to the proposed recycled water pipeline, consistent with the requirements of San Joaquin County Community Development Department, and evidence of having obtained the permit prior to construction.

Verification: Thirty (30) days prior to start of construction, the project owner shall submit to the CPM a request for a Grading Permit consistent with the requirements of San Joaquin County Community Development Department, and evidence of having obtained the permit prior to construction.

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SOIL & WATER 10: The project owner shall provide the CPM with evidence of submitting an Engineer's Report for Title 22 Reclamation Requirements to the CA Department of Health Services, as applicable for obtaining unrestricted use of recycled water.

Verification: At least 120 days prior to project operation, the project owner shall submit to the CPM evidence of submitting an Engineer's Report for Title 22 Reclamation Requirements to the CA Department of Health Services.

SOIL & WATER 11: The project owner shall provide the CPM with evidence of submitting an Application for a Water Supply Treatment Permit to the CA Department of Health Services, as applicable for treating and distributing potable water supply to more than 25 people per day, 60 or more days out of the year.

Verification: At least 120 days prior to project operation, the project owner shall submit to the CPM evidence of submitting an Application for a Water Supply Treatment Permit to the CA Department of Health Services.

SOIL & WATER 12: The project owner shall provide the CPM with evidence of submitting an Application for an Encroachment Permit applicable to the proposed directional drilling under the Delta-Mendota Canal for installation of the fresh water pipline, to the U.S. Bureau of Reclamation and Delta-Mendota Water Authority.

Verification: At least thirty (30) days prior to construction, the project owner shall submit to the CPM evidence of submitting an Application for an Encroachment Permit, to the U.S. Bureau of Reclamation and Delta-Mendota Water Authority.

REFERENCES

EAEC (East Altamont Energy Center) 2001a. Application for Certification, Volume 1 & Appendices, East Altamont Energy Center (01-AFC-4). Dated March 20, 2001 and docketed March 29, 2001.
Cited in text as: (EAEC 2001a, AFC Section #)

EAEC (East Altamont Energy Center) 2001e. Data Adequacy Response Set 1. Dated and docketed May 1, 2001.
Cited in text as: (EAEC 2001e, page #)

EAEC (East Altamont Energy Center) 2001f. Data Adequacy Response Set 2. Dated and docketed May 3, 2001.
Cited in text as: (EAEC 2001f, page #)

EAEC (East Altamont Energy Center) 2001g. Supplement A to the East Altamont Energy Center (01-AFC-4). Dated and docketed May 3, 2001.
Cited in text as: (EAEC 2001g, AFC Supplement, Section #)

NMFS (National Marine Fisheries Service) 2001a. National Marine Fisheries Service Comments on the East Altamont Energy Center AFC. Dated May 2,2001 and docketed May 7, 2001.
Cited in text as: (NMFS 2001a, page #)

EAEC (East Altamont Energy Center) 2001i. Data Adequacy Response Set 3. Dated and docketed May 7, 2001.
Cited in text as: (EAEC 2001I, page #)

CEC (California Energy Commission) 2001a. First Set of Data Requests. Dated and docketed May 10, 2001.
Cited in text as: (CEC 2001a, page #)

EAEC (East Altamont Energy Center) 2001j. Data Adequacy Response Set 4. Dated and docketed May 15, 2001.
Cited in text as: (EAEC 2001j, page #)

DWR (California State Department of Water Resources) 2001a. Comments on the East Altamont Energy Center AFC. Dated May 14, 2001 and docketed May 18, 2001.
Cited in text as: (DWR 2001a, page #)

EAEC (East Altamont Energy Center) 2001k. Revised Slope Stability Analysis for the Report of Waste Discharge Permit. Dated and docketed June 19, 2001.
Cited in text as: (EAEC 2001k, page #)

EAEC (East Altamont Energy Center) 2001l. Revised Slope Stability Analysis for the Report of Waste Discharge. Dated and docketed June 19, 2001.
Cited in text as: (EAEC 2001l, page #)

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TRAFFIC & TRANSPORTATION

David Flores

INTRODUCTION

The Traffic and Transportation section of the Preliminary Staff Assessment addresses the extent to which the project may impact the transportation system within the vicinity of its proposed location. This section analyzes the potential traffic and transportation impacts associated with construction and operation of the East Altamont Energy Center (EAEC) and its ancillary systems.

This analysis includes an evaluation of the influx of large numbers of construction workers, and how, over the course of the construction phase, the movement of these workers can increase roadway congestion and also affect traffic flow. The applicant-Calpine, D.B.A. East Altamont Energy Center, LCC - is not proposing any permanent changes to the existing transportation network after completion of construction. On-going (post construction) operations and maintenance traffic will represent a negligible increase over current conditions; however, it will include an increase in the transportation of hazardous materials to the project site. The transportation of hazardous materials will need to comply with federal and state laws.

Staff has analyzed the information provided in the AFC and from other sources to determine the potential for the EAEC to have significant traffic and transportation impacts, and has assessed the availability of mitigation measures that could reduce or eliminate the significance of those impacts. Conditions of certification are included to implement the appropriate mitigation measures and to ensure that the project complies with the applicable Laws, Ordinances, Regulations, and Standards (LORS).

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

Federal, state, and local regulations that are applicable to the proposed project are listed below. Included are regulations related to the transportation of hazardous materials, which are designed to control and mitigate for potential impacts. The Applicant has indicated its intent to comply with all federal, state, and local regulations related to the transport of hazardous materials.

FEDERAL

- Title 49, Code of Federal Regulations, Sections 171-177, governs the transportation of hazardous materials, the types of materials defined as hazardous, and the marking of the transportation vehicles.
- Title 49, Code of Federal Regulations, Sections 350-399, and Appendices A-G, Federal Motor Carrier Safety Regulations, address safety considerations for the transport of goods, materials, and substances over public highways.

STATE

California Vehicle Code

- Section 353 defines hazardous materials. Sections 31303-31309 regulate the highway transportation of hazardous materials, the routes used, and restrictions thereon.
- Sections 31600-31620 regulate the transportation of explosive materials.
- Sections 32000-32053 regulate the licensing of carriers of hazardous materials and include noticing requirements.
- Sections 32100-32109 establish special requirements for the transportation of substances presenting inhalation hazards and poisonous gases.
- Sections 34000-34121 establish special requirements for the transportation of flammable and combustible liquids over public roads and highways.
- Sections 34500, 34501, 34501.2, 34501.3, 34501.4, 34501.10, 34505.5-7, 34506, 34507.5 and 34510-11 regulate the safe operation of vehicles, including those that are used for the transportation of hazardous materials.
- Section 25160 et seq. addresses the safe transport of hazardous materials.
- Sections 2500-2505 authorize the issuance of licenses by the Commissioner of the California Highway Patrol for the transportation of hazardous materials including explosives.
- Sections 13369, 15275, and 15278 address the licensing of drivers and the classifications of licenses required for the operation of particular types of vehicles. In addition, the possession of certificates permitting the operation of vehicles transporting hazardous materials is required.
- California Streets and Highways Code, Sections 117 and 660-72, and California Vehicle Code, Section 35780 et seq., require permits for the transportation of oversized loads on county roads.
- California Street and Highways Code, Sections 660, 670, 1450, 1460 et seq., 1470, and 1480, regulate right-of-way encroachment and the granting of permits for encroachments on state and county roads.
- All construction within the public right-of-way will need to comply with the “Manual of Traffic Controls for Construction and Maintenance of Work Zones” (Caltrans, 1996).

LOCAL

ALAMEDA COUNTY

The East County Area Plan, a portion of the Alameda County General Plan, Volume 1, sets forth goals, policies, and implementation programs related to traffic issues in the County. These goals include minimum level of service (LOS) standards for local intersections. The City requires all new development projects to analyze their contribution to increased traffic and to implement improvements necessary to address the increase. According to the County's East Area Plan, the minimum desirable level of service is D during peak

commute times. However, LOS E may be acceptable when Deficiency Plans for affected roadways are prepared in conjunction with the Alameda County Congestion Management Agency.

SAN JOAQUIN COUNTY

The San Joaquin County General Plan is the County's official position on development and resource management. The General Plan contains goals, objectives, policies, diagrams, and actions. The Plan's introductory section states that " it is a commitment to a course of action that will lead, through the years, toward a desirable physical, social, and economic environment for existing and future generations." All development must be consistent with the General Plan.

The Development Title implements the General Plan. It contains specific information on zoning and development application requirements, as well as standards and regulations relating to such issues as infrastructure, natural resources, signs, setbacks, lot and yard requirements, and use types. The following transportation policies are applicable to this project:

Development Title Policy:

- Policy 1. The County shall plan for a road system of adequate capacity and design to provide reasonable and safe access by vehicles with minimum delay.

Transportation Coordination with Land Use Policies:

- Policy 1. The transportation system shall support the attainment of desired land use patterns.

- Policy 2. Transportation improvements shall be scheduled to coordinate with land use development and transportation demand.

- Policy 3. Transportation needs and access shall be considered when locating land uses.

CITY OF TRACY

The City of Tracy General Plan Urban Management Plan presents goals and policies that coordinate the transportation and circulation system with planned land uses, and promote the efficient movement of people, goods, and services within the Urban Management Planning area. The following transportation policies are applicable to this project:

- Policy Actions CI 1.2.3 Coordinate transportation planning efforts with those of adjoining jurisdictions, including San Joaquin County, the cities of Lathrop and Manteca, and Alameda and Stanislaus Counties.
- Policy Actions CI 2.2.2 Encourage City and County cooperation to establish a plan line program to preserve rights-of-way to accommodate the 2010 Land Use Plan and in anticipation of expanded urban development.

SETTING

REGIONAL DESCRIPTION

The proposed project is located on Mountain House Road, in the far eastern corner of Alameda County, approximately 8 miles northwest of the City of Tracy, 12 miles east of the City of Livermore, 5 miles south of the unincorporated community of Byron, and less than 1 mile from the San Joaquin and Contra Costa county borders. In addition to these established communities, the developing community of Mountain House is located approximately 1 mile southeast of the project site. **TRAFFIC AND TRANSPORTATION Figure 1** illustrates the major roads, potential access roads, and highways in the project area.

Local Roadways

General access to the EAEC site would be via the following roads and freeways:

Byron-Bethany Road - This is a two-lane roadway with 12-foot lanes and minimal paved shoulders. Byron-Bethany Road runs southeasterly from its intersection with Marsh Creek Road/Camino Diablo in Contra Costa County to the City of Tracy. In Alameda County, the East County Area Plan (ECAP) shows Byron-Bethany Road as a non-arterial roadway. In San Joaquin County, the roadway is shown as a major county road on the San Joaquin County

General Plan. The City of Tracy Circulation Plan classifies the roadway as a two-lane rural highway.

Mountain House Road - This is a two-lane roadway with 11-foot lanes and minimal paved shoulders. The width of the unpaved shoulders varies throughout the corridor length. The length of this roadway is approximately 4 miles, and the speed limit within the area of the project site is 50 mph. South of the intersection with Kelso Road there is a school zone, which reduces the speed to 25 mph when children are present. The City of Tracy Circulation Plan designates this roadway as a two-lane rural highway and the ECAP designates the roadway within the Transportation Diagram, but not as an arterial.

Kelso Road - This is a two-lane roadway with 10 to 11-foot lanes with little or no paved shoulders. This roadway runs east-west, and its eastern terminus is the intersection with Byron-Bethany Road. It forms intersections with Mountain House Road and Bruns Road. Kelso Road is not shown on the ECAP Transportation Diagram. The speed limit in the area of the project site is 50 mph.

The EAEC project will also require the construction of various linear facilities. A natural gas pipeline is proposed to be installed along Mountain House Road. It will begin at the site, proceed south on Mountain House Road, cross Kelso Road and turn west to proceed parallel along the road, then cross the road to the north and join with the PG&E main pipeline inside the compressor station. Total length of the pipeline is approximately 1.4 miles long.

Accident History

For roadway intersection segments, accident rates are computed as the number of accidents per million vehicle-miles of travel (MVM) over a three-year period. Byron-Bethany Road at Mountain House Road had an accident rate of 2.3 accidents per million vehicle-miles traveled. Mountain House Road at Grant Line had an accident rate of 5 accidents per MVM, Mountain House Road at Kelso Road had an accident rate of 4 accidents per MVM, and Byron-Bethany Road at Grant Line Road had an accident rate of 6 accidents per MVM. The statewide average accident rate for a similar facility is approximately 3 per MVM, with a wide range of variability. This information was provided by the Alameda County Public Works Agency (EAEC 2001a, AFC pg. 8.10-6).

County Public Works staff are quoted in the AFC, as saying that the main contributor for accidents on Grant Line and Mountain House roads is excessive speed on rural two-lane roads. The County has increased law enforcement, and considered speed bumps and stoplights, but these measures have not been implemented because the County is concerned about the potential to cause even more problems. County staff did not specify the potential problems.

With implementation of a traffic and transportation control plan as proposed in condition of certification **TRANS-1**, traffic associated with project construction would be minimized during peak hours, by requiring construction activities to occur during off-peak times. In addition, traffic volumes are expected to increase as the Mountain House community develops. Therefore, it is anticipated that average speeds will be reduced by traffic congestion. While this would remain a concern, the accident rate would be expected to decrease.

Railways

A Southern Pacific railroad line runs northeast of the proposed project site, and parallel with Byron-Bethany Road. The applicant has indicated that there are numerous pieces of heavy equipment that, due to their weight, must be transported to the site by rail. These components may be shipped by rail to the site, or to the City of Tracy and delivered to the site by heavy truck.

IMPACTS

When evaluating a project's potential impact on the local transportation system, staff uses levels of service measurements as the foundation on which to base its analysis. LOS measurements represent the flow of traffic. In general, LOS ranges from "A" with free flowing traffic, to "F" which is heavily congested with flow stopping frequently.

The following discussion identifies potential traffic impacts associated with the construction of the EAEC, and provides an explanation of the impact conclusion.

PROJECT SPECIFIC IMPACTS

CONSTRUCTION PHASE

Traffic Impacts

The project is expected to generate 512 daily trips (256 round trips) during the average construction period and 900 daily trips (450 round trips) during the peak construction period. Construction of the proposed facility, including the generating facility, gas pipeline, and electric transmission line, will take approximately 22 to 24 months. Full-time staff at the facility will consist of 125 employees on average and approximately 400 employees during peak construction months (months 11-16) (EAEC 2001a, AFC pg. 8.10-10.)

In order to assess the potential for project-related traffic to significantly affect intersections and roads within Alameda County and/or state highways under Caltrans jurisdiction, the following two scenarios were analyzed:

- existing plus peak construction traffic; and
- existing plus operation traffic.

The applicant used an analysis approach described in the 1997 Highway Capacity Manual (HCM) (EAEC 2001a, AFC Sec.8.10.2.3, pg. 8.10-12). For roadway segments, the applicant used procedures described in Chapter 8 of the HCM (Two Lane Highways). For unsignalized intersections, the applicant used procedures that measure potential capacity as described in HCM Chapter 10. Staff reviewed these sections of the HCM and concurred with their approach in analyzing the road segments in the project area.

According to the County's East Area Plan, the minimum desirable level of service is D during peak commute times. However, LOS E may be acceptable when Deficiency Plans for affected roadways are prepared in conjunction with the Alameda County Congestion Management Agency. With the exception of the intersections associated with Byron-Bethany Road in the area of the project site, the local intersections operate above the minimum established LOS thresholds. Furthermore, no decrease in LOS is evident between existing conditions, and existing plus project construction/operation traffic conditions.

The unsignalized intersections of Byron-Bethany Road with Mountain House Road and Kelso Road currently operate at LOS E conditions. The County of Alameda has plans to improve Byron-Bethany Road between Marsh Creek Road and Tracy, but the extent and timing of these improvements is currently not available. Even though the addition of construction/operation traffic to this roadway only represents a minor percentage of traffic and does not significantly reduce the LOS, it would cause a short-term increase in the congestion that already exists. Therefore, impact mitigation in the form of a construction traffic control plan and implementation program that limits construction truck and project-related commute traffic to off-peak periods, should be developed in coordination with the County of Alameda and Caltrans to offset this project impact. The Applicant has indicated their intent to provide such a plan (see **Condition of Certification TRANS-1**).

In addition, construction of linear facilities (i.e., gas/water pipelines, transmission lines) will include temporary traffic lane closures, thereby affecting the capacity of the following roadways:

- Byron-Bethany Road (includes linear road crossings and construction along the roadway segment).
- Mountain House Road (includes linear road crossings and construction along the roadway segment).
- Kelso Road (includes linear road crossings and construction along the roadway segment).

The applicant has indicated their intent to prepare a traffic control plan related to the construction of linear facilities, which will include a discussion on the use of flagmen, advanced warning flashers, and signage for temporary lane closures. In addition, this traffic control plan should include timing of linear facilities construction to take place outside of peak traffic periods, in order to avoid traffic flow disruptions.

The applicant has offered to mitigate potential traffic impacts, particularly at the intersection of Byron-Bethany Road and Mountain House Road, and road segments of Byron-Bethany Road, and Kelso Road, through the various traffic control plan measures noted above. Therefore, staff has concluded that with mitigation incorporated, impacts will be less than significant.

Impacts on Established Level of Service Standards

According to the County of Alameda General Plan, the minimum acceptable level of service is defined as D during peak commute times. However a LOS E may be acceptable when Deficiency Plans for affected roadways are prepared in conjunction with the County of Alameda Congestion Management Agency. The County requires all new development projects to analyze their contribution to increased traffic and to implement improvements and/or mitigation necessary to address the increase.

The addition of the EAEC project traffic will have little effect on the existing LOS at local intersections in the project vicinity. Each of these intersections, with the exception of Byron-Bethany Road at Mountain House Road, is expected to operate at an acceptable level of service with the addition of project construction/operation traffic (i.e., LOS D or better according to the County of Alameda's East County Area Plan). These local intersections will experience no significant and/or adverse impacts from this project. Staff has concluded that these intersections have sufficient capacity to absorb all project-generated traffic, particularly since it will be directed to avoid the a.m. and p.m. peak commute hours.

Byron-Bethany Road currently operates at LOS E. Based upon the assumptions in the AFC (Section 8.10.2.3, pg. 8.10-11 & 12), no more than one-half of the peak trips (225) would be approaching the site from any one of the directions discussed in the **SETTINGS** section of this report. It was also assumed that no more than 200 of these vehicles would

approach from any one direction during the peak hour, consistent with the current traffic patterns. Staff agrees with this assumption that if 200 vehicles are added to Byron-Bethany Road in the peak hour, the Volume Capacity Ratio (VC ratio) becomes 0.86 and LOS E is maintained. Although the addition of construction/operation traffic at this intersection would not significantly reduce the LOS and impacts would only occur on a temporary basis (i.e., during the 22-24 month construction phase of the project), it would cause a short-term increase in the congestion that already exists. Therefore, development and implementation of a construction traffic control plan should be required to offset these temporary impacts (see **Condition of Certification TRANS-1**).

Decrease in service levels resulting from temporary lane closures related to construction of linear facilities would also require the development and implementation of a construction traffic control plan to offset these traffic impacts. Staff concludes that the LOS will remain at acceptable levels during the peak construction period, despite a temporary increase in congestion, through implementation of the construction traffic control plan. Therefore, staff has concluded that with mitigation incorporated, impacts will be less than significant.

Impacts on Air Traffic Patterns

The East Altamont Energy Center has no major commercial aviation center in the area. The closest local airport is the Byron Airport in Contra Costa County, approximately three miles southeast of the proposed project site. The aircraft runway approach will not conflict with the proposed East Altamont Energy Center facility. Therefore, there will be no impact.

Impacts on Traffic Hazards

Staff observations of the project area indicate that a potential traffic operation problem or hazard could occur near the jobsite. Given that Byron-Bethany Road currently operates at LOS E, truck drivers making construction and operation phase deliveries during peak traffic periods may be delayed turning left from Byron-Bethany Road onto Mountain House Road.

Staff agrees with the applicant's intent to use the Byron-Bethany Road intersection with Kelso Road, which has a left turn lane. Staff believes that the use of this intersection will be safer and more efficient than using the Mountain House/Byron-Bethany Road intersection, which has no left turn lane. With project traffic directed to off-peak periods, the availability of the left turn lane maximizes free-flow traffic conditions on Byron-Bethany Road. It may also diminish the current phenomenon of vehicles passing along the shoulder of the roadway, causing potential hazards to pedestrians. For occasional project traffic occurring during peak periods, the availability of the left turn lane should reduce traffic delays.

Alameda County Public Works Department reviewed the Application for Certification and in their letter dated October 4, 2001, noted the potential vehicle conflicts at various intersections near the project site. To provide a safe operation at intersection locations and driveway access points, the County recommended the installation of street lights for night lighting at the driveway access points and at the following intersections:

- Mountain House Road and Byron-Bethany Road
- Mountain House Road at Kelso Road

- Mountain House Road at Grant Line Road

The street lights would be installed on existing power poles at each of the designated intersections.

The County of Alameda also expressed their concern that motorists do not currently adhere to the speed limit of 25 mph "when children are present," which is posted near the Mountain House School, located one mile south of the project site. This is especially true during commute periods of the day. Staff has addressed this concern with conditions requiring monitoring and reporting of speed limits in the area of the school and the installation of street lights, which will improve the above described roadway intersections. See **TRANS-1 and TRANS-6** for additional monitoring requirements.

Immediate access to the East Altamont Energy Center site would be provided directly from Mountain House Road. Although right and left -turn lanes are not provided for vehicles turning into the project site, excessive delays are not expected from this movement due to the relatively low level of existing traffic on Mountain House Road. Furthermore, the general public does not heavily use this road.

The applicant has stated its intent to design site access/egress to accommodate construction trucks on Kelso Road and to comply with all weight and load limitations on state and local roadways. Therefore, staff concludes that there is a less than significant impact.

Inadequate Emergency Access

The project will not lead to inadequate emergency vehicle access (EVA) because intersections affected by construction will be maintained at an acceptable service level for Alameda County's East County Area Plan.

The closest fire station within Alameda County that provides emergency services is the Alameda County Rural Fire Department's Station 8, located on College Avenue in Livermore, California. The response time from this station is approximately 20 minutes. Fire fighters are trained to handle emergency first aid. The mostly likely emergency route would be Grant Line Road to Byron-Bethany Road to the project site on Mountain House Road. If emergency evacuation is needed, the County is under contract with the American Medical Response Ambulance Service and Life Flight, an emergency helicopter response service out of Tracy. Cal Star, an emergency helicopter response service out of Stanford Hospital is also available if needed. Response time would be 15-20 minutes (Personal conversation with Alameda County Assistant Chief Purchio).

Acceptable service levels will be maintained through the implementation of a construction traffic control plan. Therefore, no traffic congestion affecting emergency access is expected on Mountain House Road or Kelso Road near the project site.

The main EVA to the site is along Mountain House Road. A secondary EVA is provided from Kelso Road.

The applicant has also indicated their intent to maintain emergency access on applicable roadways during construction of linear facilities. Therefore, staff has concluded that there is no impact.

Inadequate Parking Capacity

Staff has concluded that adequate parking will be available during the peak construction phase of the proposed project, given the applicant's proposed parking area on the north side of the project site. This onsite parking area will consist of 20 acres of land that will accommodate the peak workforce of approximately 400 workers. Therefore, development and implementation of an off-site construction employee-parking plan will not be necessary. Given the applicant's commitment to provide on-site parking, staff has concluded that there is no impact.

Transportation of Hazardous Material

The construction and operation of the plant will require the transportation of various hazardous materials, including anhydrous ammonia, solvents, lube oils, paint, paint thinners, adhesives, batteries, and construction gases. The transport of hazardous materials over county roadways has the potential to result in an increase in traffic hazards. In order to minimize potential impacts, all hazardous material deliveries should be routed as follows:

- from eastern Contra Costa County - via Byron-Bethany Road with turns at the Byron-Bethany Road-Mountain House Road intersection to project site;
- from Tracy and the Central Valley area - via Byron-Bethany Road with turn at Kelso Road; or
- from San Francisco Bay area - via I-580/I-205 using the Grant Line Road interchange and passing through the Grant Line Road/Mountain House Road intersection and the Mountain House Road/Kelso Road intersections.

The transportation and handling of hazardous substances associated with the EAEC can increase roadway hazard potential. The handling and disposal of hazardous substances are addressed in the **HAZARDOUS MATERIALS MANAGEMENT** and the **WASTE MANAGEMENT** sections of the Staff Assessment.

The State Department of Motor Vehicles specifically licenses all drivers who carry hazardous materials. Drivers are required to carry a manifest, available for inspection by the California Highway Patrol at inspection stations along major highways and interstates. Drivers are also required to check for weight limits and conduct periodic brake inspections. Commercial truck operators handling hazardous materials are also required to take instruction in first aid and procedures on handling hazardous waste spills.

The California Vehicle Code and the Streets and Highways Code (Sections 31600 through 34510) are equally important to ensure that the transportation and handling of hazardous materials are done in a manner that protects public safety. Enforcement of these statutes is under the jurisdiction of the California Highway Patrol. In addition, Interstate 280 and Interstate 580 have been approved by the California Highway Patrol as highways for use in

the transportation of inhalation related hazardous materials and there are no highway design concerns regarding the highway routes to be taken. For an in-depth description of the amount and type of hazardous materials that will be used during the construction of the facility, see the **WASTE MANAGEMENT** and **HAZARDOUS MATERIALS MANAGEMENT** sections of the Staff Assessment.

Transportation of equipment exceeding the load size and weight limits of any roadways will require special permits. The procedures and processes for obtaining such permits are fairly straightforward. Mitigation measures and conditions of certification that ensure this compliance are discussed later in this section.

The applicant has indicated that the transportation of hazardous materials to and from the site will be conducted in accordance with all applicable LORS for the handling and transportation of hazardous materials. **TRANS-5** also requires that all LORS will be complied with. Therefore, there will be a less than significant impact.

Operational phase

Commute and Visitor Traffic

The operational phase of the EAEC will require the addition of 40 full-time employees. Adequate parking will be available for these employees on site. The existing state highway and county roadway system will not be impacted by any increase in commute traffic associated with the operation of EAEC. Therefore, the commuter and visitor traffic associated with the operational phase of the project is not expected to cause any significant traffic impacts.

Truck Traffic

The transportation and handling of hazardous substances associated with the EAEC can increase roadway hazard potential. According to the AFC, operation of the project will require approximately one delivery per month of anhydrous ammonia solution.

Licensed hazardous waste transporters will provide delivery of anhydrous ammonia. Truck routes for the delivery of the anhydrous ammonia are discussed in **TRANS-1**. Highway routes for offsite removal of hazardous wastes would be I-580 to Stockton with a connection to either I-5 or SR 99 to reach any of California's three Class I hazardous waste facilities (located in Kern, Imperial and Kings Counties).

The existing state highway and county roadway system will not be significantly impacted by any increase in truck traffic associated with the operation of the EAEC project.

Potential impacts of the transportation of hazardous substances can be mitigated to insignificance by compliance with Federal and State standards (see **TRANS- 5)** established to regulate the transportation of hazardous substances.

Linear Facilities

The operation of linear facilities that would serve EAEC is not expected to have any impacts on area roadways except for short-term maintenance or unplanned difficulties. In either case, if unexpected impacts occur, the traffic flow difficulties are typically limited in duration and are not expected to cause any significant traffic impacts.

CUMULATIVE IMPACTS

Four proposed projects have been identified to occur within 1 mile and 8 miles respectively in the project area, or within the region. These two projects are described as follows:

- The Mountain House Community Service District in San Joaquin County is just less than 1 mile to the southeast of the EAEC, south of Kelso Road and expanding eastward from the San Joaquin County border. The community service district consists of an approximately 5,000-acre project proposed to include 16,000 residences, organized in 12 neighborhoods containing small commercial centers, offices, and industrial parks (San Joaquin County, 2001). Final grading of the site and installation of underground utilities has been completed on the first phase of the project, with construction of internal roadways and site pads currently underway.
- The Califia Project being developed outside of the City of Lathrop in San Joaquin County lies over 8 miles to the east of the EAEC. Lathrop has annexed 6,800 acres of land into the city limits for the project, which currently includes plans for 10,500 residences, 900 acres of preserve area, and a 5-mile system of 300 lakes. The project is expected to begin groundbreaking in three years (McCarthy, 2001).

Based on the current and future traffic characteristics (i.e. LOS, AADT, highway capacities) of the area, and various traffic patterns associated with the workers arriving and leaving the project site as discussed in this analysis, traffic associated with EAEC is minimal. Temporary project impacts at congested intersections will be mitigated through implementation of a project traffic control plan. Given this mitigation, regional and local roadways are considered to have adequate capacity to accommodate related construction traffic.

In regard to the potential for temporary cumulative traffic impacts from two power plant projects proposed in the area, Tesla Power Project (approximately 6-miles south of EAEC), and the Tracy Peaker Project (approximately 8-miles southeast of EAEC), no cumulative impacts on traffic are expected for the following reasons:

- Peak construction traffic at the Tracy Peaker project will occur prior to peak construction of the EAEC Project and the Tesla power plant proposal.
- Traffic for the EAEC project will not use the same access roads used by Tracy Peaker and Tesla Power Projects.

Several projects (Catellus, Tracy Gateway, and Bright Developments) have filed annexation applications with the County, but will not developed for several years until all environmental reviews have been conducted. Therefore, they will not affect the EAEC project. As a result of overall growth and development that is expected to occur in the

Tracy/ West San Joaquin County area, traffic volumes on the regional roadway system will likely increase. However, the project's level of traffic generation will diminish between the construction and operational phases such that an increase in background traffic should not be problematic.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the minority population is less than fifty percent within a six-mile radius of the proposed EAEC (please refer to **SOCIOECONOMICS Figure 1** in this Staff Analysis), and Census 1990 information that shows the minority/low income population is less than fifty percent within the same radius. However, there is a pocket of minority/low-income persons within six miles. Based on the Traffic and Transportation analysis, staff has not identified significant direct or cumulative impacts resulting from the construction or operation of the project. Therefore, there are no environmental justice issues related to this project.

RESPONSES TO PUBLIC AND AGENCY COMMENTS

Alameda County Community Development Agency/Public Works Agency -Dated October 4, 2001

1. *The County is concerned that potential vehicle conflicts will occur at intersections along Mountain House Road, and is therefore requesting installation of street lights for night lighting at various street intersection.*

   Staff Response: The proposed Conditions of Certification require the installation of street lights at various intersections near the project site. See discussion in the **Impacts of Traffic Hazards** section of the report.

2. *The Public Works Agency has requested the installation of deceleration and acceleration lanes, and designated left and right turn lanes at critical driveway and intersection locations.*

   Staff Response: Staff believes that the use of the existing left turn lane at Byron-Bethany Road and Kelso Road, and scheduling of workers and truck traffic to off-peak hours will lessen traffic concerns in the area of the project site. Therefore, unless the County provides specific details and justification for the improvements, staff feels that mitigation is unwarranted.

3. *The intersection of Mountain House Road at Byron-Bethany Road should be realigned to provide for a 90-degree alignment.*

   Staff Response: See staff response under Item 2.

4. *No access points should be designated on Byron-Bethany Road….*

Staff Response: The applicant is not proposing access from Byron-Bethany Road. Driveway access points proposed for Mountain House Road will be submitted to the County for review to insure installation compliance with the County's standards and specifications.

5. *For roadway and building set back, the following information should be considered: a. Future width line and special building setback line ….*

   Staff Response: The County has not specified the additional right of way requirements that the applicant would dedicate to meet the 110 -foot width line requirement, therefore staff has not addressed this issue in this analysis. The 130 -foot special building setback on Byron-Bethany Road will be adhered to once the final site plan is submitted.

6. *Areas that are reconstructed/realigned should provide a shoulder section along the roadway. The shoulder would allow for optimum recovery and emergency purposes.*

   Staff response: The construction plans that the applicant provides to the County for review, as a normal practice will include engineered section plans which will include site design and shoulder sections along the roadway. Therefore, staff has not addressed this issue, as it will be submitted with the applicant's final engineered construction plans.

7. *Existing pavement structural section along Mountain House is not adequate for the proposed commercial traffic along the roadway. Calpine should provide for roadway improvement to the existing roadway pavement structural section for a Traffic Index of 8.5.*

   Staff Response: Staff has addressed this issue in **TRANS-3**. The applicant will repair portions of Byron-Bethany Road, Mountain House Road and Kelso Road after completion of project construction. The applicant will work with the County to insure compliance with roadway repairs.

8. *In Section 8.10.1.1 Highway and Road-Public Transportation: School bus operation should be included….motorists do not adhere to the posted speed limit of 25 mph "when children are present"……*

   Staff Response: **CONDITION OF CERTIFICATION TRANS-1** requires monitoring for speed limit adherence at various roadways and intersections near the project site and Mountain House School. See **DISCUSSION OF IMPACTS ON TRAFFIC HAZARDS** section of report .

9. *The traffic volume shown in the EIR appears low. Our current traffic volume data show the following….This data or more recent traffic volumes should be considered in the traffic volume analysis.*

Staff Response: Staff has taken into account the updated traffic counts provided by Alameda County's Public Works Agency. They are reflected in staff's overall traffic analysis, specifically in the **PROJECT SPECIFIC IMPACTS** section of this report.

CONCLUSIONS

Provided that the Applicant develops a construction traffic control and implementation program, and follows all LORS acceptable to the County of Alameda and Caltrans for the handling of hazardous materials, the project will result in less than significant impacts. If the Commission approves the project, staff recommends the adoption of the following conditions to mitigate potential project impacts.

PROPOSED CONDITIONS OF CERTIFICATION

TRANS-1 The project owner shall develop a construction traffic control and transportation demand implementation program that limits construction-period truck and commute traffic to off-peak periods in coordination with the County of Alameda and Caltrans. These studies are to confirm that construction trip generation rates identified in the AFC and used to determine less than significant impacts to County of Alameda streets and are not being exceeded. Specifically, this plan shall include the following restrictions on construction traffic:

- Establish construction work hours outside of the peak traffic periods to ensure that construction workforce traffic occurs during off-peak hours, except in situations where schedule or construction activities require travel during peak hours, in which case workers will be directed to routes that will not deteriorate the peak hour level of service below the County of Alameda's LOS E standard;
- Schedule heavy vehicle equipment and building material deliveries as well as the movement of materials and equipment from laydown areas to occur during off-peak hours;
- Route all heavy vehicles and vehicles transporting hazardous materials as follows: from eastern Contra Costa County - via Byron-Bethany Road with turns at the Byron-Bethany Road-Mountain House Road intersection to project site; from Tracy and Central Valley area - via Byron-Bethany Road with turn at Kelso Road; from San Francisco Bay area - via I-580/I-205 using the Grant Line Road interchange and passing through the Grant Line Road/Mountain House Road intersection and the Mountain House Road/Kelso Road intersections.
- Every 4 months during the construction phase, monitor and report the turning movements for the intersections at Byron-Bethany Road and Mountain House Road, and Byron-Bethany Road and Kelso Road during the A.M. (7:30 to 8:30 a.m.) and P.M. (4:30 to 5:30 p.m.) peak hours to confirm construction trip generation rates.
- Every month during the construction phase, monitor and report vehicle and truck speed limits along Mountain House Road and Kelso Road, especially in

the area of Mountain House School, which is designated 25 mph when children are present.

The construction traffic control and transportation demand implementation program shall also include the following restrictions on construction traffic addressing the following issues for linear facilities:

- Timing of pipeline construction (all pipeline construction affecting local roads shall take place outside the peak traffic periods to avoid traffic flow disruptions);
- Signing, lighting, and traffic control device placement;
- Temporary travel lane closures;
- Maintaining access to adjacent residential and commercial properties; and
- Emergency access.

Verification: At least 30 days prior to site mobilization, the project owner shall provide to the County of Alameda and Caltrans for review and comment, and to the CPM for review and approval, a copy of their construction traffic control plan and transportation demand implementation program. Additionally, every 4 months during construction the project owner shall submit to the CPM turning movement studies for the intersection at Byron-Bethany Road and Mountain House Road, and Byron-Bethany Road and Kelso Road during the A.M. (7:30 to 8:30 a.m.) and P.M. (4:30 to 5:30 p.m.) peak hours.

TRANS-2 The project owner or their contractor shall comply with California Department of Transportation (Caltrans) and the County of Alameda limitations for encroachment into public rights-of-way and shall obtain necessary encroachment permits from Caltrans and all relevant jurisdictions.

Verification: In the Monthly Compliance Reports, the project owner shall submit copies of any encroachment 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-3 Following completion of project construction of the power plant and all related facilities, the project owner shall repair Mountain House Road, Kelso Road and portions of Byron-Bethany Road (underground linear facility installations) to its pre-construction condition.

Protocol: 1) The project owner shall photograph, videotape or digitally record images of portions of Byron-Bethany Road in the area of the underground linear facility installations, Mountain House Road and Kelso Road.
Protocol: 2) Prior to site mobilization, the project owner shall also notify the County of Alameda and Caltrans about the schedule for project construction. The purpose of this notification is to postpone any planned roadway resurfacing and/or improvement projects until after the project construction has taken place and to coordinate construction related activities associated with other projects.

Verification: At least 30 days prior to site mobilization, the project owner shall provide the CPM, the County of Alameda, and Caltrans (as necessary) with a copy of these images. At least 60 days after completion of project construction, the project owner shall meet with the CPM, the County of Alameda, and Caltrans (as needed) to review the photographs of the above described roadways. The agencies will determine and receive approval for schedules and actions necessary to complete the repair of identified sections of public roadways to original or as near original condition as possible. Following completion of road improvements, if necessary, the project owner shall provide to the CPM a letter from the County of Alameda stating their satisfaction with the road improvements.

TRANS-4 During construction of the power plant and all related facilities, the project owner shall enforce a policy that all project related parking occurs in designated parking areas.

Verification: At least 30 days prior to site mobilization, the project owner shall submit a parking and staging plan for all phases of project construction to the County of Alameda for review and comment, and to the CPM for review and approval.

TRANS-5 The project owner shall ensure that all federal, state, and local regulations for the transportation of hazardous materials are observed.

Verification: The project owner shall include in its Monthly Compliance Reports copies of all permits and licenses acquired by the project owner and/or subcontractors concerning the transportation of hazardous substances.

TRANS-6 Prior to site mobilization related to the project, the project owner shall pay the County of Alameda to implement street light/night lighting improvements to three intersections as identified in the mitigation section of this SA: Mountain House Road/Byron-Bethany Road, Mountain House Road /Kelso Road, and Mountain House Road/Grant Line Road.

Verification: Within 30 days of site mobilization, the project owner shall submit to the CPM evidence that the County has been paid to implement the improvements.

REFERENCES

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TRANSMISSION LINE SAFETY AND NUISANCE

Obed Odoemelam, Ph.D.

INTRODUCTION

The electrical energy from the proposed East Altamont Energy Center (EAEC) will be available for delivery to the area's 230 kV electric grid consisting of transmission lines owned by Pacific Gas and Electric (PG&E), the Western Area Power Authority (Western), the Modesto Irrigation District (MID), and the Turlock Irrigation District (TID). According to information from the applicant, Calpine D.B.A. East Altamont Energy Center, LLC (or Calpine), this delivery will be made through a new on-site EAEC Switchyard to be owned by Western as an extension of Western's existing 230 kV Tracy Substation located across Mountain House Road immediately to the west of the project site (EAEC 2001a, pages 1-2, 2-6 and 5-1). The Tracy Substation, to which these area utility lines are currently connected, will (along with the new project-related addition) continue serving as a common distribution point for power from EAEC and existing area sources.

As more fully discussed by the applicant (EAEC 2001a, page 5-14), connection from EAEC to the grid will be made by looping the existing 230 kV Tracy-Westley line (jointly owned by MID and TID) into the new EAEC Switchyard using a double-circuit 230 kV line over the 0.5 mile distance involved. This interconnection scheme would allow the power from EAEC to be introduced into the grid through either the Tracy Substation or the Wesley Substation. The location for EAEC was chosen in part for its proximity to the Tracy Substation (EAEC 2001a, page 5-1). Line construction will be according to the standard designs of PG&E, which is the main regional service utility (EAEC 2001a, pages 5-11, 5-16 and 6-17). These PG&E designs reflect compliance with existing health and safety laws, ordinances, regulations, and standards (LORS) regarding line safety and field strength reduction as will be discussed later.

Since (a) line electric fields depend on the applied voltage and conductor configuration, and (b) the same 230 kV will continue to be applied to existing area grid lines without changes in configuration, the electric fields along their respective routes would not be increased by the new power from EAEC. Only their magnetic fields would increase (since magnetic fields are the only fields whose intensities depend directly on current levels for a given design). The increase along each line route would depend on the demand-driven levels of the new EAEC energy transmitted along each transmission circuit.

The purpose of this staff analysis is to assess the proposed line construction and operational plan for incorporation of the measures necessary for compliance with the field and non-field impacts whose reduction remains the focus of the existing health and safety LORS. If such compliance were established, staff would recommend approval with respect to the issues of concern in this analysis; if not, staff would recommend revisions as appropriate. Staff's analysis will focus on the following issues as related primarily to the physical presence of the lines or secondarily to the physical interactions of their 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.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

Discussed below by subject area are design-related LORS applicable to the physical impacts of the overhead transmission lines as proposed for EAEC. The potential for these impacts is assessed in terms of compliance with specific federal or state regulations or established industry standards and practices. There presently are no local laws or regulations specifically aimed at the physical structure or dimensions of electric power lines to limit the impacts noted above. However, many local jurisdictions require such lines to be located underground because of the potential for visual impacts on the landscape.

AVIATION SAFETY

Any potential hazard to area aircraft would relate to the potential for collision in the navigable air space. The applicable federal LORS as discussed below are intended to ensure the distance and visibility necessary to prevent such collisions.

Federal

- Title 14, Part 77 of the Code of Federal Regulations (CFR), “Objects Affecting the Navigation Space.” Provisions of these regulations specify the criteria used by the Federal Aviation Administration (FAA) for determining whether a “Notice of Proposed Construction or Alteration” is required for potential obstruction hazards. The need for such a notice depends on factors related to the height of the structure, the slope of an imaginary surface from the end of nearby runways to the top of the structure, and the length of the runway involved. Such notification allows the FAA to ensure that the structure is located to avoid the aviation hazards of concern.
- FAA Advisory Circular (AC) No. 70/460-2H, “Proposed Construction and or Alteration of Objects that May Affect the Navigation Space.” This circular informs each proponent of a project that could pose an aviation hazard of the need to file the “Notice of Proposed Construction or Alteration” (Form 7640) with the FAA.
- FAA AC No. 70/460-1G, “Obstruction Marking and Lighting.” This circular 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

Transmission line-related radio-frequency interference is one of the indirect effects of line operation as produced by the physical interactions of line electric fields. Since electric fields are unable to penetrate most materials, including the soil, such interference and other electric field effects are not associated with underground lines. The level of any such

interference usually depends on the magnitude of the electric fields involved. Because of this, the potential for such impacts could be assessed from field strength estimates obtained for the line. The following regulations are intended to ensure that such lines are located away from areas of potential interference and that any interference is mitigated whenever it occurs.

Federal

- Federal Communications Commission (FCC) regulations in Title 47 CFR, Section 15.25. Provisions of these regulations prohibit operation of any devices producing force fields, which interfere with radio communications, even if (as with transmission lines) such devices are not intentionally designed to produce radio-frequency energy. 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 FCC requires each line operator to mitigate all complaints about interference on a case-specific basis. Staff usually recommends specific conditions of certification to ensure compliance with this FCC requirement.

State

- General Order 52 (GO-52), California Public Utilities Commission (CPUC). Provisions of this order govern the construction and operation of power and communications lines and specifically deal with measures to prevent or mitigate inductive interference. Such interference is produced by the electric field induced by the line in the antenna of a radio signal receiver.

Several design and maintenance options are available for minimizing these electric field-related impacts. When incorporated into the line design and operation, such measures also serve to reduce the line-related audible noise discussed below.

AUDIBLE NOISE

Industry Standards

There are no design-specific federal regulations to limit the audible noise from transmission lines. As with radio noise, such 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. All modern overhead high-voltage lines are designed to assure compliance. As with radio-frequency noise, such 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 higher. It is, therefore, not generally expected at significant levels from those of less than 345 kV such as the ones proposed for EAEC. 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 100-ft right-of-way.

NUISANCE SHOCKS

Industry Standards

There are no design-specific federal 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). 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 electric and magnetic fields. As with the proposed overhead lines, the applicant will be responsible in all cases for ensuring compliance with these grounding-related practices within the right-of-way. Staff usually recommends specific conditions of certification as necessary to ensure that such grounding is made along the route.

FIRE HAZARDS

The fire hazards addressed through the following regulations 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.

State

- General Order 95 (GO-95), CPUC, “Rules for Overhead Electric Line Construction” specifies tree-trimming criteria to minimize the potential for power line-related fires.
- Title 14 Section 1250 of the California Code of Regulations: “Fire Prevention Standards for Electric Utilities” specifies utility-related measures for fire prevention.

HAZARDOUS SHOCKS

The hazardous shocks addressed by the following regulations and standards 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.

State

- GO-95, CPUC. “Rules for Overhead Line Construction” These rules specify uniform statewide requirements for overhead line construction regarding ground clearance, grounding, maintenance and inspection. Implementing these requirements ensures the safety of the general public and line workers.

- Title 8, CCR, Section 2700 et seq., Sections 2700 through 2974. "High Voltage Electric Safety Orders" These safety orders establish essential requirements and minimum standards for safely installing, operating, working around, and maintaining electrical installations and equipment

Local

There are no shock hazard-related requirements on the physical dimensions of power lines at the local level.

Industrial Standards

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 in the National Electrical Safety Code, Part 2: Safety Rules for Overhead Lines. These provisions specify the minimum national safe operating clearances applicable in areas where the line might be accessible to the public. They are intended to minimize the potential for direct or indirect contact with the energized line.

ELECTRIC AND MAGNETIC FIELD (EMF) EXPOSURE

The possibility of deleterious health effects from electric and magnetic field exposure has increased public concern in recent years about living near high-voltage lines. Both fields occur together whenever electricity flows, hence the general practice of describing exposure to them together as EMF exposure. The available evidence as evaluated by CPUC, other regulatory agencies, and staff, has not established that such fields pose a significant health hazard to exposed humans. However, 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 reduction of such fields as feasible without affecting safety, efficiency, reliability and maintainability.

While there is considerable uncertainty about the EMF/health effects issue, 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.
- The measures employed for such field reduction can affect line safety, reliability, efficiency and maintainability, depending on the type and extent of such measures.

State

In California, the CPUC (which regulates the installation and operation of high-voltage lines in California) 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 required 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. Utilities 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 of 1989.

In keeping with this CPUC policy, staff requires evidence that each proposed overhead line will be designed according to the 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 issues bearing on safety, reliability efficiency and maintainability. Therefore, it is up to each applicant to ensure that such measures are applied to an extent without significant impacts on line operation and safety. The extent of such applications would be reflected by the 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 each lines for effectiveness at field strength reduction. 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 structures, degree of cancellation from nearby conductors, distance between conductors and, in the case of magnetic fields, amount of current in the line.

Since each new line in California is currently required to be designed according to the EMF-reducing guidelines of the utility in the service area involved, its fields are required under existing CPUC policies to be similar to fields from similar lines in that service area. A condition of certification is usually proposed by staff to ensure implementation of the design measures necessary. The applicable condition for this project is **TLSN-1**.

Industrial Standards

There are no health-based federal regulations or industry codes specifying environmental limits on the strengths of fields from power lines. However, the federal government continues to conduct and encourage research necessary for an appropriate policy on the EMF health issue.

In the face of the present uncertainty, several states have opted for design-driven regulations ensuring that fields from new lines are generally similar to those from existing lines. Some states (Florida, Minnesota, New Jersey, New York, Montana) have set specific environmental limits on one or both fields in this regard. These limits are, however, not based on any specific health effects. Most regulatory agencies believe, as does staff, 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.

Before the present health-based concern developed, measures to reduce field effects from power line operations were mostly aimed at the electric field component whose effects can manifest themselves as the previously noted radio noise, audible noise and nuisance

shocks. The present focus is on the magnetic field because only it can penetrate the soil, building and other materials to potentially produce the types of health impacts at the root of the present concern. As one focuses on the strong magnetic fields from the more visible overhead transmission and other high-voltage power lines, staff considers it important for perspective, to note that an individual in a home could be exposed for short periods to much stronger fields while using some common household appliances (National Institute of Environmental Health Services and the U.S Department of Energy, 1995). 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.

SETTING

According to information from the applicant (EAEC 2001a, page 8.4-2), the proposed EAEC and related switchyard will be located on a 55-acre lot within a 174-acre parcel in rural Alameda County. The site, which is near the borders of Santa Clara and San Joaquin counties, is within an area with many infrastructure projects, the most important of which are Western's Tracy Substation, two pumping stations for the Delta-Mendota Canal and the California Aqueduct, a PG&E compressor station, numerous wind farms, four 500 kV lines, four 230 kV lines, and several lines of lower voltage. A listing of these area transmission lines was provided by the applicant together with information on voltage ratings and current-carrying capacities (EAEC 2001a, page 5-3).

The project site is bounded to the north by Byron Bethany Road, to the south by Kelso Road, and to the west by Mountain House Road. The low population density of this rural area should serve to minimize the residential magnetic field exposure at the root of the present health concern; the site is currently used for grazing and crop farming. The only project-related EMF exposures of potential significance are the short-term exposures to plant workers, regulatory inspectors, maintenance personnel, approved guests, or individuals in transit across the project's lines. These types of exposures are short term and well understood as not significantly related to the present health concern.

PROJECT DESCRIPTION

The proposed EAEC lines will consist of the segments listed below:

- Two new double-circuit overhead lines (on two parallel tower structures) extending the 0.5 mile distance from the proposed on-site EAEC Switchyard to the existing Tracy-Westley double-circuit 230 kV line;
- The new EAEC Switchyard; and
- Project-related modifications at the existing Western's Tracy Substation.

The existing Tracy-Westley (MID/TID) line to be interconnected was built as a double-circuit line but is currently operated as a single-circuit line and will remain the same during EAEC operations. However, specific EAEC-related modifications on the line would allow for use of a double-circuit connection between the existing Tracy Substation and its project-related extension. Such use of a double-circuit connection is intended to improve the reliability of

system operations (EAEC 2001a, page 5-13). The proposed lines will be located within a right-of-way of 380 feet.

Each of these lines will be carried on tubular steel support towers as with the existing Tracy-Westley line to which they will be connected. The basic structure of these support towers was provided by the applicant as relevant to field reduction effectiveness (EAEC 2001a, page 5-24). These towers are typically 110 ft tall and of the same design as those for Tracy-Westley line. Details of the proposed tower placement scheme have been provided by the applicant (EAEC 2001a, pages 5-6, and 5-24). Since the proposed project lines are to be constructed and operated according to standard PG&E practices, they will be designed according to those aspects of these practices that minimize line electric and magnetic fields. The focus of staff's analysis is on the intensities of these new line fields and the level of their potential contribution to existing area fields levels.

IMPACTS

GENERAL IMPACTS

GO-95, and Title 8, CCR Section 2700 et seq., as noted in the LORS section, ensure the minimum regulatory requirements necessary to prevent the direct or indirect contact previously discussed in connection with hazardous shocks or aviation hazards. Of secondary concern are the noted field impacts manifesting themselves as nuisance shocks, radio noise, communications interference and magnetic field exposure. The relative magnitude of such impacts would be reflected in the field strengths characteristic of a given line design. Since applied field-reducing measures can affect line operations and safety, the extent of their implementation and resulting field strengths will vary according to environmental and other local conditions bearing on line safety, efficiency, reliability and maintainability. They will, therefore, vary from one service area to the other according to prevailing conditions. It would be up to each project proponent to apply such measures to the extent appropriate for the geographic area involved.

PROJECT SPECIFIC IMPACTS

Aviation Safety

As noted by the applicant (EAEC 2001a, page 5-18) the nearest airport to the project site is Byron Airport, approximately 2.8 nautical miles to the northeast. Given this distance and the orientation of the airport's runway, staff considers the proposed line as unlikely to pose a significant obstruction hazard to utilizing aircraft as define according using FAA criteria. Therefore no FAA "Notice of Construction or Alteration" will be required. However, the owners of new transmission lines usually contact the FAA about such lines as a standard industry practice.

Interference with Radio-Frequency Communication

The previously noted corona-related communications interference is most commonly caused by irregularities (such as nicks and scrapes on the conductor surface), sharp edges on suspension hardware, and other discontinuities around the conductor surface. The proposed lines will be built and maintained according to PG&E practices, minimizing

such surface irregularities and discontinuities (EAEC 2001a, pages 5-10 and 5-16). Moreover, the potential for such corona-related interference is usually of concern only for lines of 345 kV and above, and not the proposed 230 kV lines (except in rainy weather when the presence of raindrops increases the strengths of the offending surface electric fields). The low-corona design for the proposed project lines would be the same as used for the exiting 230 kV lines to which the lines would be connected. Since these existing lines do not currently produce the corona effects of specific concern, staff does not expect any corona-related radio-frequency interference any where around the proposed route. In the unlikely event of specific complaints, the applicant would be responsible for the necessary mitigation as required by the FCC. Staff recommends a specific condition of certification (**TLSN-3**) in this regard.

Audible Noise

As happens with radio noise, the low-corona design for the proposed EAEC lines will minimize the potential for corona-related audible noise (as with similar PG&E and other area lines). This means, as reflected in the applicant's calculations (EAEA 2001a, Appendix 5.5C), that the proposed interconnection line will not add significantly to current background noise levels in the project area. For an assessment of the noise from all phases of the proposed project and related facilities, please refer to staff's analysis in the **Noise** section.

Fire Hazards

Standard fire prevention and suppression measures for all PG&E lines will be implemented for the proposed lines (EAEC 2001a, page 5-18). The applicant's intended compliance with the clearance-related aspects of GO-95 would be an important part of this compliance approach. Moreover, the route for the proposed interconnection lines will have no trees or brush as it traverses Kelso Road and the agricultural field between Kelso Road and the new project substation.

Hazardous Shocks

The applicant's noted intention to implement the GO-95- related measures against direct contact with the energized line (EAEC 2001a, pages 5-11 and 5-16) will serve to minimize the risk of hazardous shocks. Staff recommends condition of certification **TLSN-1** to ensure implementation of the necessary mitigation measures.

Nuisance Shocks

As is current PG&E practice, the potential for nuisance shocks around the proposed lines will be minimized through standard grounding practices (EAEC 2001a, pages 5-17 and 5-18). Staff recommends condition for certification, **TLSN-2** to ensure such grounding.

Electric and magnetic field exposure

Maximum field strengths along the routes of the proposed and existing area lines were calculated by the applicant (EAEC 2001a, pages 5-15, 5-16 and Appendix 5.5-D) to assess the potential contribution of EAEC's lines to the area's electric and magnetic field levels together with the need for additional mitigation. Staff has verified the accuracy of the applicant's calculations with regard to parameters bearing on field strength dissipation and exposure assessment. Since there will be no EAEC-related changes to system voltage or

conductor configurations as previously noted, there will be no change to existing system electric fields and their noted impacts.

The maximum magnetic fields within the route of the proposed interconnecting lines was calculated as 136.5 mG at the centerline, diminishing to 30 mG at the east edge of the right-of-way and 16.5 mG at the west edge. These field strength values are, as staff would expect for PG&E lines of the same voltage and current-carrying capacity. The maximum intensity along the route of the 230 kV project- to-Westley line was calculated to increase from 91.4 mG to 136.3 at the centerline and from 20.1 mG to 30.0 mG on both sides of the right-of-way. The maximum strengths along the route of the area's 500 kV and 230 kV PG&E lines (within a common corridor) was calculated to increase from 87.9 mG to 97.2 mG during EAEC operations. The increase at the edge of the right-of-way was calculated as slightly changing to the east edge from 57.7 mG to 58.2 mG, and from 13.3 mG to 24.5 mG at the west edge. Such field strength changes show the added power from the proposed EAEC as adding magnetic fields at levels staff expects for similar PG&E lines. These resulting field strengths are much lower than the 150 to 230 mG established for the edge of the rights-of-way by the few states with regulatory limits on these line magnetic fields.

The applicant has identified the field reduction approaches incorporated into the existing area and proposed EAEC-related line design at issue (EAEC 2001a, pages 5-16 and 5-17). These measures include the following:

1. Increasing the distance between the conductors and the ground;
2. Reducing the spacing between the conductors;
3 Minimizing the current in the line; and
4 Arranging current flow to maximize the cancellation effects from interacting fields from nearby conductors.

Since these field reducing measures have been incorporated into the proposed line design to the extent considered by PG&E as without impacts on line safety, efficiency, reliability and maintainability, staff considers further mitigation as unnecessary but recommend a specific condition of certification (**TLSN-4**) to validate the reduction efficiency assumed by the applicant.

CUMULATIVE IMPACTS

The reported field strengths were calculated by the applicant to factor the interactive effects of the fields from the proposed and nearby PG&E lines. Therefore, these values should be seen as representing cumulative exposures from the project's and existing area PG&E lines. As reflected in the calculated values, any such exposures would be similar to those associated with PG&E lines of similar voltage and current-carrying capacity.

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

Since electric or magnetic field health effects have neither been established nor ruled out for overhead and underground lines, the public health significance of any EAEC-related field exposures cannot be characterized with certainty. The long-term, mostly residential magnetic exposure at the root of the present health concern will be insignificant for the proposed interconnection lines given the general absence of residences along the proposed route. On-site worker or public exposures would be short term and at levels expected for similar PG&E designs and current-carrying capacity. Such exposures are well understood and have not been established as posing a health hazard to humans.

The potential for nuisance shocks will be minimized through grounding and other field-reducing measures to be implemented by the applicant in keeping with current PG&E guidelines reflecting common industry practices. Since there are no major airports or aviation centers in the immediate project area, staff does not expect the proposed lines to pose a significant aviation hazard. The use of low-corona line design together with appropriate corona-minimizing construction practices will minimize the potential for corona noise and its related interference with radio-frequency communication anywhere in the project area.

RECOMMENDATIONS

Since the project's interconnecting 230 kV lines will be designed to minimize the safety and nuisance impacts of specific concern to staff while routed through an area with few residences, staff does not consider further exposure-related mitigation as necessary and recommends that the line be approved as proposed. If such approval is granted, staff would recommend that the Energy Commission adopt the conditions of certification specified below to ensure implementation of the measures necessary to achieve the field reduction and line safety assumed by the applicant.

CONDITIONS OF CERTIFICATION

TLSN-1 The project owner shall construct the proposed interconnection transmission lines according to the requirements of CPUC's GO-95, GO-52, Title 8, Section 2700 et seq. of the California Code of Regulations and PG&E's EMF reduction guidelines arising from CPUC Decision 93-11-013 of 1989.

Verification: Thirty days before starting construction of the CPP's transmission line or related structures and facilities, the project owner shall submit to the Commission's Compliance Project Manager (CPM) a letter signed by a California registered electrical engineer affirming that the overhead section will be constructed according to the requirements GO-95, GO 52, Title 8, Section 2700 et seq. of the California Code of Regulations, and PG&E's EMF-reduction guidelines arising from CPUC Decision 93-11-013.

TLSN-2 The project owner shall ensure that all metallic objects along the route of the overhead section are grounded according to industry standards.

Verification: At least 30 days before the lines are energized, the project owner shall transmit to the CPM a letter confirming compliance with this condition.

TLSN-3 The project owner shall take reasonable steps to resolve any complaints of interference with radio or television signals from operation of the proposed lines.

Verification: Any reports of line-related complaints shall be summarized along with related mitigation measures for the first five years, and provided in an annual report to the CPM.

TLSN-4 The project owner shall engage a qualified consultant to measure the strengths of the line electric and magnetic fields from the proposed lines before and after they are energized. Measurements shall be made at representative points (on-site and along the line route) as necessary to identify the maximum field exposures possible during EAEC 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.

REFERENCES

EAEC (East Altamont Energy Center) 2001a. Application for Certification, Volumes I and II. Submitted to the California Energy Commission on March 20, 2001.

Electric Power Research Institute (EPRI) 1982. Transmission Line Reference Book: 345 kV and Above.

Energy Commission Staff 1992. High Voltage Transmission Lines: Summary of Health Effects Studies. California Energy Commission Publication, P700-92-002.

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

Michael Clayton and Will Walters

SUMMARY

Energy Commission staff analyzed both the potential visual impacts of the proposed East Altamont Energy Center (EAEC) and the compliance of the project with applicable laws, ordinances, regulations, and standards (LORS). The proposed project would be prominently situated next to two Alameda County-designated scenic corridors in a highly visible location. At this time, staff's conclusions are as follows:

- As presently proposed, the project's structures would result in significant visual impacts. Staff has proposed mitigation to enhance the applicant's proposed landscaping plan for project screening. However, it should be noted that biology staff of the California Energy Commission (CEC), California Department of Fish and Game (CDFG), and U.S. Fish and Wildlife Service (USFWS) are concerned about potential biological impacts of the proposed landscaping. To address this issue, the applicant recently prepared a revised landscaping plan. Staff will evaluate this new landscaping plan and present the results in the Final Staff Assessment. If the revised landscape plan would not result in full and timely implementation of staff's proposed landscaping mitigation, or if the mitigation is determined to not be feasible, significant visual impacts from the proposed project structures would remain.
- Staff has concluded that in the seven cases of the project's inconsistency or partial consistency with local LORS, either the inconsistencies did not initially produce significant visual impacts, or with full and effective implementation of all mitigation measures and staff's conditions of certification, the visual impacts causing the inconsistencies would be mitigated to levels that would not be significant.
- The proposed project's HRSG and cooling tower vapor plumes would be sufficiently frequent and large such that the resulting visual impact would be significant. However, full implementation of staff's Conditions of Certification **VIS-7** and **VIS-8** would reduce the visual impact to a level that would not be significant.
- Mitigation measures proposed by the applicant and expanded by staff (Condition **VIS-4**) would reduce lighting impacts to levels that would not be significant. Staff's proposed Mitigation Measure 19 (Condition of Certification **VIS-9**) would offset the project's contribution to cumulative significant lighting impacts.

INTRODUCTION

Visual resources are the natural and cultural features of the environment that can be viewed. This analysis focuses on whether EAEC would cause significant adverse visual impacts and whether the project would be in compliance with applicable laws, ordinances, regulations, and standards. The determination of the potential for significant impacts to visual resources resulting from the proposed project is required by the California Environmental Quality Act (CEQA).

ORGANIZATION OF ANALYSIS

This analysis is organized as follows:

- Description of analysis methodology;
- Description of applicable laws, ordinances, regulations and standards;
- Description of the project aspects that may have the potential for significant visual impacts;
- Assessment of the visual setting of the proposed power plant site and linear facility routes;
- Evaluation of the visual impacts of the proposed project on the existing setting;
- Evaluation of compliance of the project with applicable laws, ordinances, regulations, and standards;
- Identification of measures needed to mitigate any potential significant adverse impacts of the proposed project and to achieve compliance with applicable laws, ordinances, regulations, and standards.
- Conclusions and Recommendations; and
- Proposed Conditions of Certification

ANALYSIS METHODOLOGY

Visual resources analysis has an inherently subjective aspect. However, the use of generally accepted criteria for determining impact significance and a clearly described analytical approach aid in developing an analysis that can be readily understood.

SIGNIFICANCE CRITERIA

Commission staff considered the following criteria in determining whether a visual impact would be significant.

State

The CEQA Guidelines define 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 (Cal. Code Regs., tit.14, § 15382).

Appendix G of the Guidelines, under Aesthetics, lists the following four questions to be addressed regarding whether the potential impacts of a project are significant:

1. Would the project have a substantial adverse effect on a scenic vista?

2. Would the project substantially damage scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a state scenic highway?

3. Would the project substantially degrade the existing visual character or quality of the site and its surroundings?

4. Would the project create a new source of substantial light or glare that would adversely affect day or nighttime views in the area?

Local

Energy Commission staff considers any local goals, policies, or designations regarding visual resources. Conflicts with such laws, ordinances, regulations, and standards can constitute significant visual impacts. See the section on Laws, Ordinances, Regulations, and Standards.

Professional Standards

Professionals in visual impact analysis have developed a number of questions as a means of evaluating the potential significance of visual impacts (see Smardon 1986). The questions listed below address issues commonly raised in visual analyses for energy facilities. Staff considers these questions in assessing whether a project would cause a significant impact in regard to any of the four CEQA criteria listed above.

- Will the project substantially alter the existing viewshed, including any changes in natural terrain?
- Will the project deviate substantially from the form, line, color, and texture of existing elements of the viewshed that contribute to visual quality?
- Will the project eliminate or block views of valuable visual resources?
- Will the project result in significant amounts of backscatter light into the nighttime sky?
- Will the project be in conflict with directly identified public preferences regarding visual resources?
- Will the project result in a significant reduction of sunlight, or the introduction of shadows, in areas used extensively by the community?
- Will the project result in a substantial and persistent visible exhaust plume?

IMPACT DURATION

The visual analysis typically distinguishes three different impact durations. **Temporary impacts** typically last no longer than two years. **Short-term impacts** generally last no longer than five years. **Long-term impacts** are impacts with a duration greater than five years.

VIEW AREAS AND KEY OBSERVATION POINTS

The proposed project is visible from a number of areas in the project region. Energy Commission staff evaluated the visual impact of the project from each of these areas. Staff used Key Observation Points[1], or KOPs, as representative locations from which to conduct detailed analyses of the proposed project and to obtain existing conditions photographs and prepare visual simulations. KOPs are selected to be representative of

[1] The use of KOPs or similar view locations is common in visual resource analysis. The US Bureau of Land Management and the US Forest Service use such an approach.

the most critical locations from which the project would be seen. However, KOPs are not the only locations that staff considered in each view area.

EVALUATION PROCESS

For each view area, staff considered the existing visual setting and the visual changes that the project would cause to determine impact significance. Staff conducted a site visit and concluded that the KOPs presented in the Application were appropriate for this analysis. However, staff did request that all photographs and simulations be revised to life-size scale. The results of staff's analysis are summarized in **VISUAL RESOURCES Appendix VR-1**. Existing conditions photographs and photosimulations from each KOP are presented with all other figures in **VISUAL RESOURCES Appendix VR-3**.

Elements of the Visual Setting

To assess the existing visual setting, staff considered the following elements:

Visual Quality

Visual quality is an expression of the visual impression or appeal of a given landscape and the associated public value attributed to the visual resource. This analysis used an approach that considers visual quality as ranging from outstanding to low. Outstanding visual quality is a rating reserved for landscapes that would be what a viewer might think of as "picture postcard" landscapes. Low visual quality describes landscapes that are often dominated by visually discordant human alterations, and do not provide views that people would find inviting or interesting (Buhyoff et al., 1994).

Viewer Concern

Viewer concern is a measurement of the level of viewer interest regarding the visual resources in an area. Official statements of public values and goals reflect viewers' expectations regarding a visual setting. This analysis also employed land use as an indicator of viewer concern. Uses associated with 1) designated parks, monuments, and wilderness areas, 2) scenic highways and corridors, 3) recreational areas, and 4) residential areas are generally considered to have high viewer concern. However, existing landscape character may temper viewer concern on some State and locally designated scenic highways and corridors. Similarly, travelers on other highways and roads, including those in agricultural areas, may have moderate viewer concern depending on viewer expectations as conditioned by regional and local landscape features. Commercial uses, including business parks, typically have low-to-moderate viewer concern, though some commercial developments have specific requirements related to visual quality, with respect to landscaping, building height limitations, building design, and prohibition of above-ground utility lines, that indicate high viewer concern. Industrial uses typically have the lowest viewer concern because workers are focused on their work, and generally are working in surroundings with relatively low visual value.

Viewer Exposure

The visibility of a landscape feature, the viewing distance to the landscape feature, the number of viewers, and the duration of the view all affect the exposure of viewers to a given landscape feature. Visibility is highly dependent on screening and angle of view. The smaller the degree of screening and/or the closer the feature is to the center of the

view area, the greater its visibility is. Increasing distance reduces visibility. Viewer exposure can range from low values for all factors, such as a partially obscured and brief background view for a few motorists, to high values for all factors, such as an unobstructed foreground view from a large number of residences.

Visual Sensitivity

The overall level of sensitivity of a view area to impacts due to visual change is a function of visual quality, viewer concern, and viewer exposure and can range from low to high.

Types of Visual Change

To assess the visual changes that the project would cause, staff considered the following factors:

Contrast

Visual contrast describes the degree to which a project's visual characteristics or elements (consisting of form, line, color, and texture) differ from the same visual elements established in the existing landscape. The degree of contrast can range from low to high. The presence of forms, lines, colors, and textures in the landscape similar to those of a proposed project indicates a landscape more capable of accepting those project characteristics than a landscape where those elements are absent. This ability to accept alteration is often referred to as visual absorption capability and typically is inversely proportional to visual contrast.

Dominance

Another measure of visual change is project dominance. Dominance is a measure of a feature's apparent size relative to other visible landscape features and the total field of view. A feature's dominance is affected by its relative location in the field of view and the distance between the viewer and the feature. The level of dominance can range from subordinate to dominant.

View Blockage

View blockage describes the extent to which any previously visible landscape features are blocked from view by the project. Blockage of higher quality landscape features by lower quality project features causes adverse visual impacts. The degree of view blockage can range from none to high.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The following discussion of Federal, State, and Local laws, ordinances, regulations, and standards is based on Section 8.11.5 (LORS) of the Application for Certification (EAEC 2001a, AFC pages 8.11-23 through 28).

FEDERAL

The proposed project is located on private land. Therefore, the project is not subject to federal regulations pertaining to visual resources.

STATE

In the project vicinity, Interstate 580 (I-580) has been designated eligible for State Scenic Highway status (State Scenic Highway System Web Site: www.dot.ca.gov/hq/LandArch/scenic/cahisys.htm). When a highway has been designated "scenic," the local jurisdiction is required to enact a scenic corridor protection program that protects and enhances scenic resources. A properly enforced program can mitigate the effects of uses that might otherwise detract from the scenic values of the corridor landscape. A corridor protection program would typically stipulate specific siting, landscaping, and screening requirements; as well as require appropriate structural characteristics and surface treatments to make new development more compatible with the existing environment.

LOCAL

The proposed generating facility site, two alternative transmission line alignments, and the gas line alternatives are located in unincorporated areas of Alameda County. The waterline alternatives are partially located in Alameda County and Contra Costa County while the recycled water alternatives are partially located in Alameda County, San Joaquin County, and Contra Costa County. Therefore, the proposed project would be subject to any local laws, ordinances, regulations, and standards (LORS) pertaining to the protection and maintenance of visual resources in Alameda, Contra Costa, and San Joaquin Counties.

Sixteen applicable LORS from Alameda County are found in the Alameda County East County Area Plan, the Alameda County Scenic Route Element of the General Plan, and the Alameda County Zoning Ordinance. Five sections of the San Joaquin County General Plan contain a total of seven visual resource related policies that are applicable to the proposed project. Four applicable policies from Contra Costa County are found in the Scenic Route section of the General Plan Transportation & Circulation Element. The relevant local LORS and an assessment of the project's LORS consistency are presented in a later section of this analysis.

PROJECT DESCRIPTION

The following section describes the aspects of the project that may have the potential for significant visual impacts and includes the power plant and associated facilities, switchyard, electric transmission interconnection, natural gas pipeline, and water supply pipeline (see **PROJECT DESCRIPTION Figure 2**).

POWER PLANT AND ASSOCIATED FACILITIES

The proposed generating facility would occupy 55 acres of a 174-acre agricultural parcel consisting of flat valley land that extends along the east side of Mountain House Road from Kelso Road to Byron Bethany Road. The most visible features of the proposed project would include the three 175-foot tall HRSG stacks, the 65-foot tall air inlets to the combustion turbine generators (CTGs), the 57-foot tall steam turbine generator, the 100-foot tall auxiliary boiler stack, the 90-foot tall brine concentrator, and the 57-foot tall, 1,030-foot long cooling tower structure consisting of 19 cells (see **PROJECT DESCRIPTION Figure 2**). Other features associated with the generation

site include ancillary structures; parking areas; an 8-foot non-reflective chain link fence, with an additional 2 feet of barbed or razor wire; a one million-gallon brine concentrator feed tank, a 300,000-gallon RO feed storage tank; a 1.7-acre stormwater retention pond; and lighting (which is addressed in a separate section later in this analysis).

SWITCHYARD

A new on-site switchyard would be located immediately south of the steam turbine generator facilities. Components of the new switchyard, including transformers, take-off structures, and other electrical equipment, would have an industrial appearance similar to that of the components in the nearby Tracy Substation. The A-frame takeoff structures would be approximately 51 feet in height.

ELECTRICAL TRANSMISSION INTERCONNECTION

Power generated by the proposed project would be transferred over two new 0.5-mile long, double circuit 230 kV transmission lines that would exit the switchyard in parallel to the south and connect to the MID/TID 230 kV transmission line located along the south side of Kelso Road. **PROJECT DESCRIPTION Figure 2** shows the location of the proposed transmission lines. The MID/TID 230 kV line connects to Western's Tracy Substation on the west side of Mountain House Road, across from the proposed project site. The new angle and dead-end structures would be tubular steel with a neutral gray finish and range in height from 110 feet to 125 feet. The conductors would be non-specular to reduce visibility and the insulators would be non-reflective and non-refractive.

NATURAL GAS PIPELINE

The proposed underground pipeline would be approximately 1.4 miles in length, extending from PG&E's existing gas transmission line southeast of the Bethany gas compressor station (near the intersection of Bruns and Kelso Roads) to the proposed project site along Kelso Road. Three alternatives to the proposed route would extend from various points along the existing PG&E gas line (west to southwest of the project site) to the proposed project site.

Associated with the gas pipeline would be a gas metering station at the interconnection with the PG&E gas pipeline. The metering station would consist of several aboveground pipeline segments (extending no more than six feet above the ground), valves, and a small structure for controls. All major components would be painted neutral earth-tone colors. In the case of the proposed route and one of the alternatives, the metering station would be located at the PG&E gas compressor station. The metering stations associated with the other gas pipeline alternative routes would be located along the portion of the PG&E gas pipeline adjacent to the Delta-Mendota Canal.

WATER SUPPLY PIPELINE

The proposed 2.1-mile, 24-inch underground pipeline (Route 3E) would convey approximately 4,600 acre-feet per year of raw water for cooling tower and process makeup water from the Byron Bethany Irrigation District (BBID) Canal 45 located to the west of the proposed project site and just east of the California Aqueduct. Three

alternatives to the proposed route (Routes 3A, 3B, and 3D) would extend from the same BBID Canal 45 connection point via different routes, and one route would extend from Canal 45 at its intersection with Mountain House Road, south of the project site.

The water supply pipeline would require a water pump station at the starting point at BBID Canal 45. The station would consist of several pumps mounted on a concrete pad. The pumps could extend up to 10 feet in height.

An alternative to the use of raw water is the use of reclaimed water. Two alternative pipeline routes could convey reclaimed water from the future Mountain House Community Services District wastewater treatment plant, located near a branch of the Old River, to the project site. Either alternative would require the installation of a pump station adjacent to the treatment plant and the installation of an underground 24-inch pipeline. Alternative 4A would be approximately 4.3 miles in length and would extend from the pump station west along Bethany Road, northwest along Byron Bethany Road, and west along Kelso Road to the project site. Preferred Alternative 4B would be approximately 4.6 miles in length and would extend from the pump station west along Bethany Road and then northwest along Byron Bethany Road to the project site.

SETTING

REGIONAL LANDSCAPE

The proposed project would be located in the northeastern corner of Alameda County, east of the Coast Range and on the edge of the Sacramento-San Joaquin Delta within the San Joaquin Valley landscape zone. The region is characterized by flat valley lands generally divided into large fields of row crops with some grazing land, periodically punctuated by the vertical forms of tall trees associated with windrows along field edges and farm dwellings. The flat valley floor appears to extend to the horizon on the north, east, and southeast. To the west and southwest, the landscape is framed by the grass- and brush-covered Coast Range and a sub-unit – the Diablo Range (to the south). The Coast Range in this area is characterized by a set of southeast-northwest trending ridges that are generally 800 to 1,200 feet in elevation, but which in places rise up to higher peaks. The most prominent Coastal Range landmarks visible from the project area are Brushy Peak, which is 7 miles to the west of the project site and 1,702 feet in elevation, and Mount Diablo, which is 19 miles northwest of the project site and 3,849 feet in elevation (EAEC 2001a, AFC p. 8.11-1). The region is also noteworthy for the profusion of wind turbines scattered across the Coastal Range in this area, the numerous electric transmission lines converging on Tracy Substation, and the numerous canals associated with the California Water Project and Central Valley Project including the California Aqueduct and the Delta Mendota Canal.
Several recreation facilities are also found in the project area. The Livermore Yacht Club functions as a recreational area oriented toward boating and fishing on the Delta waterways. The Rivers End Marina, located adjacent to the Livermore Yacht Club, provides a boat ramp, boat slips, and on-ground boat storage. At the eastern end of Clifton Court Road, approximately 2.3 miles northeast of the project site, portions of the shoreline of the Clifton Court Forebay and the California Aqueduct are open to the public for bank fishing and in season, waterfowl hunting. The Lazy M Marina, which is

adjacent to this area, provides a boat ramp, berths, on-ground boat storage, a small restaurant, and cabins. At the Bethany Reservoir located two miles southwest of the site, the California Department of Parks and Recreation operates the 600-acre Bethany Reservoir State Recreation Area. Developed facilities include a boat ramp, dock, and picnic and parking areas. In addition, the facility serves as a staging area for a bikeway that has been developed along the segment of the California Aqueduct that extends southward from the reservoir (EAEC 2001a, AFC pp. 8.11-3 & 4).

PROJECT VIEWSHED

The distance zones used within this analysis are defined as *foreground* (0 to 1/2 mile), *middleground* (1/2 to 2 miles), and *background* (beyond 2 miles). **Within these zones of influence are a number of viewing opportunities. Most foreground to middleground views of the proposed project would be limited to adjacent and nearby roadways and residences. The powerplant would be noticeably visible from Byron Bethany Road, Mountain House Road, Kelso Road, and Lindeman Road. Viewers would typically be motorists travelling in directions toward the project site and a few scattered rural residents along the roads referenced above. The principal viewing corridor and the area of greatest concern is along Byron Bethany Road which carries the most travelers in the immediate project vicinity, and which is also an Alameda County-designated scenic route as is Mountain House Road.**

The unabated plumes from the HRSG stacks and cooling tower (based on a 10% frequency of occurrence during seasonal daylight hours from November through April) would rise approximately 508 to 656 feet (for the HRSG) and 876 feet (for the cooling tower) above their respective stacks and extend downwind approximately 1,043 to 1,873 feet for the HRSG and 6,337 feet for the cooling tower. Therefore, the viewshed of the plumes would extend substantially farther out across the valley than the viewshed for the structures and would include more distant roadways generally within the area defined by I-5 on the east, I-580 (a state eligible scenic route) on the south, the Coast Range to the west, and Clifton Court and Howard Roads on the North. Vista views of the plumes would also be available from Brushy Peak and Mount Diablo to the west. However, from the more distant Mount Diablo, visibility would be reduced as a result of the substantial 19-mile viewing distance.

IMMEDIATE POWER PLANT VICINITY

The visual character of the immediate project vicinity reflects several layers of human use. In addition to being an agricultural landscape devoted to large-scale crop production, it is also a landscape in which a large number of infrastructure facilities have been sited, creating a scene that is a mosaic of the rural and technological. Much of the infrastructure is associated with the nearby transfer point between the California Department of Water Resources' (DWR) California Water Project and the U.S. Bureau of Reclamation's (USBR) Central Valley Project. DWR's 2,180-acre Clifton Court Forebay is 1.3 miles north of the project site . From the Forebay, water passes to the south through the California Aqueduct located to the west of the project site. Also to the west of the project site is the Delta-Mendota Canal with high, grass-covered levees. Immediately west of the project site is Tracy Substation, from which a number of electric transmission lines radiate out from across the valley floor, several of which pass in close proximity to the project site.

The immediate vicinity also includes a scattering of residential uses and a school. These uses are visible in the open, panoramic agricultural scene usually with a cluster of trees in the otherwise flat landscape. The residences closest to the project site are

individual farm dwellings, which are typically surrounded by outbuildings and trees. Approximately 0.75-mile northeast of the project site, the Livermore Yacht Club includes a small cluster of approximately 30 residences, which are built immediately adjacent to the Old River and are oriented toward the water. In the corridor along Mountain House Road, approximately 0.75-mile southwest of the project site, is another small cluster of residences. Most of these residences are located along the west side of Mountain House Road to the south of Kelso Road. Mountain House School, a public elementary school serving approximately 60 students, is also located in this area along Mountain House Road, approximately one mile south of the project site.

ELECTRICAL TRANSMISSION INTERCONNECTION

The proposed electrical transmission interconnection is located within the power plant vicinity, described above.

CONSTRUCTION LAYDOWN AREAS

The proposed construction laydown areas are located within the power plant vicinity, described above.

VIEWING AREAS AND KEY OBSERVATION POINTS

Staff evaluated the visual setting and proposed project in detail from several viewing areas represented by six key viewpoints including: (1) Byron Bethany Road at the intersection with Mountain House Road, (2) Mountain House Road, just north of Kelso Road, (3) Mountain House Road at Mountain House School, (4) Kelso Road (westbound) approximately 0.55 mile southeast of the project site, (5) Byron Bethany Road at the intersection with Lindeman Road (the access road to the Livermore Yacht Club), and (6) Kelso Road approximately 0.45 mile east of the project site (viewing the transmission line).

Each of these key observation points is shown on **VISUAL RESOURCES Figure 1**. At each KOP a visual analysis was conducted, the results of which are presented in Appendix VR-1. Existing conditions photographs are presented in Appendix VR-3. A discussion of the visual setting for each KOP is presented in the following paragraphs.

KOP 1 – Byron Bethany Road at Mountain House Road

KOP 1 represents the view to the south from the intersection of Byron Bethany Road and Mountain House Road (see **VISUAL RESOURCES Figure 2A**). This viewpoint is approximately 0.4 mile north of the proposed site's northern boundary and 0.5 mile from the proposed project's closest structures. From this location, the proposed project would be within the "cone of vision" (45 degrees either side of the direction of travel) of southbound motorists on Byron Bethany Road and Mountain House Road. Byron Bethany Road is an Alameda County-designated scenic route (as is Mountain House Road) and is a major arterial with an average daily traffic (ADT) level of 13,820 vehicles per day (EAEC 2001a, AFC p. 8.11-8).

Visual Quality

From this viewpoint, the most prominent features in the existing landscape are the flat, open agricultural fields that occupy the foreground and middleground; the local

roadways that transition from foreground to middleground, the electric transmission structures converging on Tracy Substation, Tracy Substation with its complex of vertical forms and lines, and the distant hills of the Diablo Range. The view from KOP 1 encompasses a foreground to middleground flat, agricultural landscape dominated by electric transmission infrastructure and backdropped by the low, rolling to curvilinear landforms of the Diablo Range to the south. Also prominent in views from KOP 1 are the local roadways and the adjacent wood pole lines. Although the overall landscape character is rural agricultural, landscape character becomes more industrial in appearance in close proximity to Tracy Substation as a result of the profusion of energy transmission structures converging on and associated with the substation. Visual quality is low-to-moderate.

Viewer Concern

Since Mountain House Road and Byron Bethany Road primarily serve local traffic, most motorists on these roads would be sufficiently familiar with local conditions to anticipate a foreground to middleground rural agricultural landscape with a prominent energy transmission infrastructure presence. However, viewers' expectations would also include open panoramic vistas across the flat valley floor to the hills to the south. Although such views are partially obscured by the intermittent presence of transmission structures, the lattice construction of the towers renders them partially "transparent" and prevents the complete blockage of the hills beyond. Any additional blockage of vista views along either roadway would be perceived as an adverse visual change and viewer concern is moderate-to-high.

Viewer Exposure

Site visibility is high in that the view of the site from KOP 1 is open and unobstructed at a foreground viewing distance of approximately 0.5 mile. Although the number of viewers is high, the duration of view is moderate and overall viewer exposure is high.

Overall Visual Sensitivity

For southbound motorists on Byron Bethany Road and Mountain House Road, the low-to-moderate visual quality somewhat tempers the moderate-to-high viewer concern and high viewer exposure. The resulting overall sensitivity of the visual setting experienced from KOP 1 is moderate-to-high.

KOP 2 – Mountain House Road

KOP 2 represents the view to the north from northbound Mountain House Road, just north of the intersection with Kelso Road (see **VISUAL RESOURCES Figure 3A**). This viewpoint is approximately 0.3 mile south of the proposed site's southern boundary and 0.5 mile from the proposed project's closest structures. From this location, the proposed project would be within the "cone of vision" (45 degrees either side of the direction of travel) of northbound motorists on Mountain House Road. Mountain House Road has an estimated ADT of 1,800 vehicles per day (EAEC 2001a, AFC p. 8.11-9). This view is also representative of the views from the residences in the farm complex on the southwest corner of the 174-acre project parcel. However, it should be noted that if the project is implemented, all residential use of these structures will cease.

Visual Quality

From this viewpoint, the most prominent features in the existing landscape are the flat, open agricultural fields that occupy much of the foreground and middleground to the east; the linear form of Mountain House Road transitioning from foreground to middleground with the adjacent wood pole line; the electric transmission structures converging on Tracy Substation (out of the frame of the photograph to the left); and the substation with its complex of vertical structural forms and lines and industrial character. Visual quality of this rural agricultural landscape is low-to-moderate and reflects the influence of the technological and industrial character imparted by Tracy Substation and the presence of numerous transmission lines.

Viewer Concern

Northbound motorists on Mountain House Road anticipate a foreground to middleground rural agricultural landscape with a prominent energy transmission infrastructure presence. However, viewers' expectations include open panoramic vistas north across the flat valley floor to the distant horizon. Although such views are partially obscured by the intermittent presence of transmission structures, the lattice construction of the towers renders them partially "transparent" and prevents the complete blockage of the sky and horizon beyond. Although the highly industrialized character of Tracy Substation immediately adjacent to this viewpoint influences viewer expectations along this portion of Mountain House Road, any additional view blockage of natural features by project structural elements would be perceived as an adverse visual change and overall viewer concern is moderate.

Viewer Exposure

Site visibility is high in that the view of the site from KOP 2 is open and unobstructed at a foreground viewing distance of approximately 0.5 mile. The number of viewers and duration of view are moderate and overall viewer exposure is moderate-to-high.

Overall Visual Sensitivity

For northbound motorists on Mountain House Road, the low-to-moderate visual quality, moderate viewer concern, and moderate-to-high viewer exposure result in an overall moderate visual sensitivity.

KOP 3 – Mountain House Road at Mountain House School

KOP 3 represents the view to the north from the Mountain House School and the adjacent residence (see **VISUAL RESOURCES Figure 4A**). This viewpoint is approximately 0.8 mile south of the proposed site's southern boundary and 0.9 mile from the proposed project's closest structures. From this location, the proposed project would also be within the cone of vision of northbound motorists on Mountain House Road.

Visual Quality

From this viewpoint, the most prominent features in the existing landscape are the flat, open agricultural fields that occupy much of the foreground and middleground to the east; the linear form of Mountain House Road transitioning from foreground to middleground with the adjacent wood pole line; and the electric transmission structures

along Kelso Road that converge on Tracy Substation (out of the frame of the photograph to the left). Visual quality of this rural agricultural landscape is low-to-moderate and reflects a balance between the industrial character of nearby transmission infrastructure and the open panoramic views of a rural agricultural scene generally lacking in distinctive landscape features.

Viewer Concern

Viewers in proximity of the school and adjacent residence, as well as northbound motorists on Mountain House Road anticipate a foreground to middleground rural agricultural landscape with a noticeable middleground presence of electric transmission structures. However, viewers' expectations include open panoramic vistas north and east across the flat valley floor to the distant horizon. Any additional view blockage of natural features by project structural elements would be perceived as an adverse visual change and overall viewer concern is moderate.

Viewer Exposure

The view of the site from KOP 3 is open and unobstructed at a middleground viewing distance of approximately 0.9 mile and while it is within the cone of vision of northbound motorists on Mountain House Road, it is situated at an indirect angle of view for the occupants of the school and residence. Therefore, the resulting site visibility is moderate. The number of viewers is also moderate and the duration of view is moderate-to-extended. Overall viewer exposure is moderate.

Overall Visual Sensitivity

The low-to-moderate visual quality, moderate viewer concern, and moderate viewer exposure result in an overall moderate visual sensitivity.

KOP 4 – Kelso Road

KOP 4 represents the view to the northwest from westbound Kelso Road, approximately 0.55 mile southeast of the project site's southeastern corner, 0.65 mile southeast of the switchyard, and 0.75 mile southeast of the closest generating facility structures (see **VISUAL RESOURCES Figure 5A**). This viewpoint was selected to represent views toward the project site from the vicinity of the two residences located on the north side of Kelso Road and the farm complex containing two additional residences located on the south side of Kelso Road. The proposed project would also be near the edge of the cone of vision of westbound motorists on Kelso Road.

Visual Quality

From this viewpoint, the most prominent features in the existing landscape are the flat, open agricultural fields that occupy much of the foreground and middleground; the rolling foothills of the Coast Range, the linear form of Kelso Road as it transitions from the foreground to middleground; and the electric transmission structures converging on Tracy Substation, which is out of the frame of the photograph (to the left). Visual quality of this rural agricultural landscape is low-to-moderate, reflecting the absence of distinguishing visual characteristics and the influence of the industrial character imparted by the convergence of numerous transmission lines on Tracy Substation.

Viewer Concern

Residents in the vicinity of KOP 4 and westbound motorists on Kelso Road anticipate a foreground to middleground rural agricultural landscape and the presence of electric transmission lines. However, the introduction of additional energy infrastructure with prominent geometric forms and complex industrial character, accompanied by additional view blockage would be perceived as an adverse visual change. Overall viewer concern is moderate.

Viewer Exposure

Site visibility is high in that the view of the site from KOP 4 is open and unobstructed at a middleground viewing distance of approximately 0.75 mile. The number of residential viewers is low as is the traffic volume on Kelso Road with an estimated 600 vehicles per day (EAEC 2001a, AFC p. 8.10-5). The duration of view ranges from moderate for vehicles on Kelso Road to extended for residential viewers. The resulting overall viewer exposure is moderate.

Overall Visual Sensitivity

For residents and motorists on Kelso Road, the low-to-moderate visual quality and moderate viewer concern and exposure result in an overall moderate visual sensitivity.

KOP 5 – Byron Bethany Road at Lindeman Road

KOP 5 represents the view to the west from the intersection of Byron Bethany Road and Lindeman Road (see **VISUAL RESOURCES Figure 6A**). This viewpoint is approximately 0.75 mile from the proposed site's eastern boundary and 0.78 mile from the proposed project's closest structures. From this location, the proposed project would be within the cone of vision of northbound motorists on Byron Bethany Road, which is an Alameda County-designated scenic route and is a major arterial with an average daily traffic (ADT) level of 13,820 vehicles per day (EAEC 2001a, AFC p. 8.11-8). Lindeman Road provides the primary means of access to and egress from Rivers End Marina and the cluster of approximately 30 residences in the Livermore Yacht Club area (EAEC 2001a, AFC p. 8.11-11).

Visual Quality

From this viewpoint, the most prominent features in the existing landscape are the flat open agricultural fields that occupy the foreground and middleground, Byron Bethany Road transitioning from foreground to middleground with its prominent linear form and diagonal lines, the vertical forms of numerous electric transmission structures converging on Tracy Substation, Tracy Substation with its complex of vertical forms and lines, and the rolling to angular forms and curvilinear lines of the Coast Range including Brushy Peak and Mount Diablo, which is a visible regional landmark. Visual quality is moderate and reflects the visual variety of the flat valley floor, rolling hills, and visual interest created by the prominent angular form of Mount Diablo. Although electric transmission infrastructure and wind turbines on the hills are visible in the landscape, they are not dominant landscape features at this middleground to background viewing distance.

Viewer Concern

Motorists on Byron Bethany Road and Lindeman Road anticipate a foreground to middleground rural agricultural landscape with the presence of energy transmission infrastructure. However, viewers' expectations include open, panoramic vistas across the flat valley with minimal obstruction of views to the hills and Mount Diablo to the west. Although such views are partially obscured by the intermittent presence of transmission structures, the lattice construction of most of the towers renders them partially "transparent" and prevents the complete blockage of the hills in the background. Any additional blockage of vista views from either roadway would be perceived as an adverse visual change and viewer concern is moderate-to-high.

Viewer Exposure

Site visibility is high in that the view of the site from KOP 5 is open and unobstructed at a middleground viewing distance of approximately 0.78 mile. However, it should be noted that as a viewpoint representative of the visual experience along Byron Bethany Road, viewing distances will range from background to foreground as northbound motorists converge on the site from the east. The number of viewers is high and the duration of view is extended as the site is within view of westbound traffic for over one mile. Overall viewer exposure is high.

Overall Visual Sensitivity

For northbound motorists on Byron Bethany Road, the moderate visual quality of the existing landscape combined with moderate-to-high viewer concern and high viewer exposure results in a visual setting with an overall moderate-to-high visual sensitivity.

KOP 6 – Kelso Road (Transmission Line)

KOP 6 represents the view to the west from westbound Kelso Road toward the alignment of the proposed transmission interconnection. This viewpoint is approximately 0.45 mile east of Mountain House Road at the western edge of a farmstead located on the north side of Kelso Road. This viewpoint was selected to represent views of both westbound motorists on Kelso Road and the nearby residents (see **VISUAL RESOURCES Figure 7A**). The proposed transmission line crossing of Kelso Road would be in a direct line of sight for westbound motorists.

Visual Quality

Views from this KOP encompass a foreground flat, agricultural landscape with considerable electric transmission infrastructure. Visual quality of this rural agricultural landscape is low-to-moderate, reflecting the general absence of distinguishing visual features and the influence of industrial character imparted by the existing substation and numerous transmission lines.

Viewer Concern

Residents in the vicinity of KOP 6 and westbound motorists on Kelso Road anticipate a foreground to middleground rural agricultural landscape and the presence of electric transmission lines. However, the introduction of additional energy infrastructure with industrial character, accompanied by additional view blockage would be perceived as an adverse visual change. Overall viewer concern is moderate.

Viewer Exposure

Site visibility is high in that the view of the site from KOP 6 is open and unobstructed at a foreground viewing distance of approximately 0.35 mile from the proposed transmission line crossing of Kelso Road. While the number of viewers is low, the duration of view is extended, resulting in a moderate-to-high overall viewer exposure.

Overall Visual Sensitivity

For residents and motorists on Kelso Road, the low-to-moderate visual quality and moderate viewer concern result in a moderate overall visual sensitivity when combined with the moderate-to-high viewer exposure that would occur at this KOP.

IMPACTS

CONSTRUCTION IMPACTS

Construction of the proposed power plant and linear facilities would cause temporary adverse visual impacts due to the presence of equipment, materials, and workforce. Construction would involve the use of cranes, heavy construction equipment, temporary storage and office facilities, and temporary laydown/staging areas. Construction would include site clearing and grading, ditching of construction sites, construction of the actual facilities, and site and rights-of-way cleanup and restoration. The proposed project construction would occur over a 24-month period. Due to the relatively short-term nature of project construction, the adverse visual impacts that would occur during construction would not be significant. However, this conclusion assumes that complete restoration of construction areas and rights-of-way is accomplished. Proper implementation of Condition of Certification **VIS-1** would ensure that the visual impacts associated with project construction remain less than significant.

Also, while the majority of construction activities would occur during daylight hours when supplemental lighting would not be needed, some construction activity may occur during night to make up schedule deficiencies (EAEC 2001a, AFC p. 2-23). In order to ensure that significant construction lighting impacts do not occur, staff has recommended Condition of Certification **VIS-4**, presented later in this analysis.

OPERATION IMPACTS

An analysis of operation impacts was conducted for the view areas represented by the key viewpoints selected for in-depth visual analysis. The results of the operation impact analysis is discussed below by KOP and presented in the Visual Analysis Summary table included as **Visual Resources Appendix VR-1**. The visual impacts of vapor plume formation and night lighting are discussed in separate sections of this analysis. For each KOP, an evaluation of visual contrast, project dominance, and view blockage is presented with a concluding assessment of the overall degree of visual change caused by the proposed project.

Impacts of Power Plant Structures

Table 1 presents the heights for a number of the project's key components. As shown in the table, the most prominent project structures would be the three 175-foot tall HRSG stacks, the 65-foot tall air inlets to the combustion turbine generators (CTGs), the 57-foot tall steam turbine generator, the 100-foot tall auxiliary boiler stack, the 90-foot tall brine concentrator, and the 57-foot tall, 1,030-foot long cooling tower structure consisting of 19 cells.

Table 1
Dimensions of Key Project Components

Component	Height[1] (feet)	Length (feet)	Diameter / Width (feet)
HRSG Structure (to top of highest relief valve)	108		
HRSG Drums (to top of highest)	87		
HRSG Stacks	175		20
HRSG Casings	73	150	60
Gas Combustion Turbine Air Inlet Filters	65	60	40
Steam Turbine Generator Enclosure	57	115	32
Auxiliary Boiler Stack	100		4
Cooling Tower Structure	57	1,030	
Two Brine Concentrators	90		20
Two Brine Crystallizers	100 (approx.)		15 (approx.)
Raw Water Tanks	40		150
Demineralized Water Storage Tanks	40		52
Switchyard Conductor Take-off Structures	56		

1 Source: EAEC 2001a, AFC Table 8.11-2

KOP 1 – Byron Bethany Road at Mountain House Road

VISUAL RESOURCES Figure 2B presents a visual simulation of the proposed project as viewed from KOP 1 at the intersection of Byron Bethany Road and Mountain House Road. The most obvious change to the landscape would be the introduction of prominent geometric forms with horizontal to vertical lines and complex industrial character. The resulting structural mass would be substantially greater than that of the surrounding facilities.

Visual Contrast

The proposed project would introduce the prominent geometric forms and vertical and horizontal lines of the HRSG structures and stacks. The project would also introduce the prominent horizontal, rectilinear form of the 19-cell cooling tower structure. These structural characteristics would not be consistent with the existing forms and lines established by the adjacent electric transmission infrastructure. Also, the scale of these introduced forms and structural masses would be substantially larger than other developed features in the immediate project vicinity. The resulting visual contrast would be high (see the Visual Analysis Summary table presented as **Visual Resources Appendix VR-1**).

Project Dominance

The rural agricultural landscape visible from KOP 1 is dominated by the flat, horizontal form of the valley floor and the prominent vertical forms of electric transmission line structures. The proposed power plant facilities would be spatially prominent in the

center of the view of this highly exposed site and the large scale of the proposed facilities would dominate the other built features. Without landscaping the project would appear co-dominant with the existing landforms. Also, the height of the vertical HRSG stacks would contribute to the structural prominence of the proposed facilities. Overall project dominance would be an intermediate level of co-dominant-to-dominant.

View Blockage

From KOP 1 the vertical HRSG structures and stacks and horizontal 19-cell cooling tower structure (lower quality landscape features) would block from view portions of sky and Coast Range hills (higher quality landscape features). The Coast Range hills are prominently visible to the south. However, this noticeable view blockage would be of short duration as a vehicle's position relative to the project site changes. Also, the more prominent (higher elevation) portion of the Coast Range hills with greater visual draw is further to the west and would not be blocked from view. The resulting view blockage would be moderate-to-high.

Overall Visual Change

From KOP 1, the overall visual change caused by the proposed project would be moderate-to-high due to the high degree of contrast that would occur from the project's co-dominant-to-dominant structures, combined with the project's moderate-to-high degree of view blockage of higher quality landscape features (Coast Range).

Visual Impact Significance

When considered within the context of the overall moderate-to-high visual sensitivity of the existing landscape and viewing characteristics, the moderate-to-high visual change that would be perceived from KOP 1 would cause an adverse and significant visual impact.

KOP 2 –Mountain House Road

VISUAL RESOURCES Figure 3B presents a visual simulation of the proposed project as viewed from KOP 2, on northbound Mountain House Road, just north of Kelso Road. The most obvious change to the landscape would be the introduction of prominent and complex geometric forms with horizontal to vertical lines and industrial character. The resulting structural mass would be substantially greater than that of the existing electric transmission facilities in the immediate project vicinity.

Visual Contrast

The proposed project would introduce the prominent geometric forms and vertical and horizontal lines of the HRSG structures and stacks. The project would also introduce the prominent horizontal, rectilinear form of the 19-cell cooling tower structure. These structural characteristics would not be consistent with the existing forms and lines established by the adjacent electric transmission infrastructure. Also, the scale of these introduced forms and structural masses would be substantially larger than other developed features in the immediate project vicinity. The resulting visual contrast would be high (see the Visual Analysis Summary table presented as **Visual Resources Appendix VR-1**).

Project Dominance

The rural agricultural landscape visible from KOP 2 is dominated by the flat, horizontal form of the valley floor and the prominent vertical forms of electric transmission line structures. The proposed power plant facilities would be spatially prominent in the center of the view of this highly exposed site and the large scale of the proposed facilities would dominate the other built features. The project would appear co-dominant with existing landforms. Also, the height of the vertical HRSG stacks would contribute to the structural prominence of the proposed facilities. Overall project dominance would be co-dominant.

View Blockage

From KOP 2 the proposed project structures (lower quality landscape features) would block from view a portion of sky and a relatively small portion of Coast Range hills (higher quality landscape features). While the Coast Range hills are noticeable background features, the more prominent (higher elevation) portion of the Coast Range hills with greater visual draw is farther to the south of the project's background (to the left of the structures shown in **VISUAL RESOURCES Figure 3B**). The resulting view blockage is therefore, less severe than it would otherwise be if more prominent, higher quality landscape features were blocked from view. Also, the proposed structures would screen from view some of the existing electric transmission infrastructure, which appears relatively low on the horizon. The proposed project's resulting view blockage would be moderate.

Overall Visual Change

From KOP 2, the overall visual change caused by the proposed project would be moderate-to-high due to the high degree of contrast that would result from the project's co-dominant structures, combined with the project's moderate degree of view blockage of higher quality landscape features (Coast Range and sky).

Visual Impact Significance

When considered within the context of the overall moderate visual sensitivity of the existing landscape and viewing characteristics, the moderate-to-high visual change that would be perceived from KOP 2 would cause an adverse and significant visual impact.

KOP 3 – Mountain House Road at Mountain House School

VISUAL RESOURCES Figure 4B presents a visual simulation of the proposed project as viewed from KOP 3, on Mountain House Road, at the Mountain House School. The most obvious change to the landscape would be the introduction of prominent and complex geometric forms with horizontal to vertical lines and considerable industrial character. The resulting structural mass would be noticeably greater than that of the existing electric transmission facilities in the immediate project vicinity.

Visual Contrast

The proposed project would introduce prominent geometric forms and vertical and horizontal lines associated with the HRSG structures and stacks, as well as the complex industrial character of the project's ancillary facilities, pipe racks, and equipment. The project would also introduce the prominent horizontal, rectilinear form of the 19-cell

cooling tower structure and several prominent linear electric transmission towers. These structural characteristics would not be consistent with the existing forms and lines established by the adjacent electric transmission infrastructure. Also, the scale of these introduced forms and structural masses would be substantially larger than other developed features in the immediate project vicinity. The resulting visual contrast would be high at this middleground viewing distance (see **Visual Resources Appendix VR-1**).

Project Dominance

The rural agricultural landscape visible from KOP 3 is dominated by the flat, horizontal form of the valley floor and the prominent vertical forms of electric transmission line structures, the linear form of Mountain House Road, and roadside utility poles. The proposed power plant facilities would be spatially prominent in the center of the view of this highly exposed site and the large scale of the proposed facilities would dominate the other built features. The project would appear co-dominant with existing landforms. Also, the height of the vertical HRSG stacks would contribute to the structural prominence of the proposed facilities. Overall project dominance would be co-dominant.

View Blockage

From KOP 3 the proposed project structures (lower quality landscape features) would block from view portions of sky and valley floor (higher quality landscape features) near the horizon line. Also, the project's foreground to middleground transmission structures and conductors would partially obscure a horizontal swath of sky above the horizon line. However, because those existing landscape features that would be blocked from view are relatively low on the horizon and generally lacking notable scenic qualities, the resulting view blockage would be less severe than it would otherwise be if more prominent, higher quality landscape features were blocked from view. The proposed project's resulting view blockage would be moderate.

Overall Visual Change

From KOP 3, the overall visual change caused by the proposed project would be moderate-to-high due to the high degree of contrast that would result from the project's co-dominant structures, combined with the project's moderate degree of view blockage of higher quality landscape features (sky and valley floor).

Visual Impact Significance

When considered within the context of the overall moderate visual sensitivity of the existing landscape and viewing characteristics, the moderate-to-high visual change that would be perceived from KOP 3 would cause an adverse and significant visual impact.

KOP 4 – Kelso Road

VISUAL RESOURCES Figure 5B presents a visual simulation of the proposed project as viewed from KOP 4, on Kelso Road, approximately 0.55 mile southeast of the project site. The most obvious change to the landscape would be the introduction of prominent and complex geometric forms with horizontal to vertical lines and industrial character.

The resulting structural mass would be substantially greater than that of the existing electric transmission facilities in the immediate project vicinity.

Visual Contrast

The proposed project would introduce prominent geometric forms and vertical and horizontal lines associated with the HRSG facilities and 19-cell cooling tower, as well as the complex industrial character of the project's ancillary facilities, pipe racks, and equipment. These structural characteristics would not be consistent with the existing simple horizontal forms and lines of the valley landform or the linear forms of the adjacent electric transmission infrastructure (transmission towers and conductors). Also, the scale of these introduced forms and structural masses would be substantially larger than other developed features in the immediate project vicinity. The resulting visual contrast would be high (see **Visual Resources Appendix VR-1**).

Project Dominance

The rural agricultural landscape visible from KOP 4 is dominated by the flat, horizontal form of the valley floor. The proposed power plant facilities would be spatially prominent in the center of the view of this highly exposed site and the large scale of the proposed facilities would dominate the other built features. The project would appear co-dominant with the existing landform of the valley floor. Also, the height of the vertical HRSG stacks would contribute to the structural prominence of the proposed facilities. Overall project dominance would be an intermediate level of co-dominant-to-dominant.

View Blockage

From KOP 4 the proposed project structures (lower quality landscape features) would block from view portions of sky and valley floor (higher quality landscape feature) near the horizon. However, because those existing landscape features that would be blocked from view are relatively low on the horizon and generally lacking notable scenic qualities, the resulting view blockage would be less severe than it would otherwise be if more prominent, higher quality landscape features were blocked from view. The proposed project's resulting view blockage would be moderate.

Overall Visual Change

From KOP 4, the overall visual change caused by the proposed project would be moderate-to-high due to the high degree of contrast that would result from the project's co-dominant-to-dominant structures, combined with the project's moderate degree of view blockage of higher quality landscape features (sky and valley floor).

Visual Impact Significance

When considered within the context of the overall moderate visual sensitivity of the existing landscape and viewing characteristics, the moderate-to-high visual change that would be perceived from KOP 4 would cause an adverse and significant visual impact.

KOP 5 –Byron Bethany Road at Lindeman Road

VISUAL RESOURCES Figure 6B presents a visual simulation of the proposed project as viewed from KOP 5 at the intersection of Byron Bethany Road and Lindeman Road. The most obvious change to the landscape would be the introduction of prominent

geometric forms with horizontal to vertical lines and complex industrial character. The resulting structural mass would be substantially greater than that of the surrounding facilities.

Visual Contrast

The proposed project would introduce the prominent geometric forms and vertical and horizontal lines associated with the HRSG structures and stacks and 19-cell cooling tower, as well as the complex industrial character of the project's ancillary facilities, pipe racks, and equipment. These structural characteristics would not be consistent with the forms and lines established by the broad, horizontal landform of the valley floor, rolling to angular landforms of the Coast Range, and adjacent linear electric transmission infrastructure. Also, the scale of these introduced forms and structural masses would be substantially larger than other developed features in the immediate project vicinity. The resulting visual contrast would be high (see Visual Resources Appendix VR-1).

Project Dominance

The rural agricultural landscape visible from KOP 5 is dominated by the rolling to angular forms of the Coast Range hills in the background to the west, and the flat, horizontal form of the valley floor, which is punctuated by the vertical forms of electric transmission line structures. The proposed power plant facilities would be spatially prominent in the center of the view of this highly exposed site and the large scale of the proposed facilities would dominate the other built features. The project would appear co-dominant with the existing landform of the valley floor. Also, the height of the vertical HRSG stacks, silhouetted against the sky, would contribute to the structural prominence of the proposed facilities. Overall project dominance would be an intermediate level of co-dominant-to-dominant.

View Blockage

From KOP 5 the proposed project structures (lower quality landscape features) would block from view a small portion of sky and portions of the Coast Range and Mount Diablo (higher quality landscape features) which are prominently visible in the background to the west of the site. However, this noticeable view blockage of prominent landscape features with significant visual draw would be a transient experience as a viewer's (vehicle on Byron Bethany Road) position changes relative to the project site. The resulting view blockage would be moderate-to-high as opposed to high, which would be the case if the view of Mount Diablo and Brushy Peak were continually blocked from view while traveling down Byron Bethany Road.

Overall Visual Change

From KOP 5, the overall visual change caused by the proposed project would be moderate-to-high due to the high degree of contrast that would occur from the project's co-dominant-to-dominant structures combined with the project's moderate-to-high degree of view blockage of higher quality landscape features (sky, Coast Range hills, and Mount Diablo).

Visual Impact Significance

When considered within the context of the overall moderate-to-high visual sensitivity of the existing landscape and viewing characteristics, the moderate-to-high visual change that would be perceived from KOP 5 would cause an adverse and significant visual impact.

KOP 6 – Kelso Road (Transmission Corridor)

VISUAL RESOURCES Figure 7B presents a visual simulation of the proposed project as viewed from KOP 6, on Kelso Road, approximately 0.45 mile east of Mountain House Road. This KOP was established to evaluate the proposed electric transmission interconnection as it approaches and then spans Kelso Road. The most obvious change to the landscape would be the introduction of additional transmission structures into the foreground landscape.

Visual Contrast

The proposed project's transmission interconnection would introduce linear forms and vertical to horizontal lines, similar to those of the existing transmission lines in the project vicinity. However, the prominent horizontal lines of the transmission line conductors would contrast with the diagonal lines of existing conductors and vertical lines of existing structures. The scale of the introduced forms would be similar to existing developed features in the immediate project vicinity. The resulting visual contrast would be an intermediate level of low-to-moderate at this foreground viewing distance (see **Visual Resources Appendix VR-1**).

Project Dominance

The rural agricultural landscape visible from KOP 6 is dominated by the flat, horizontal form of the valley floor, the vertical forms of electric transmission line structures, the linear form of Kelso Road, and roadside utility poles. The proposed transmission line facilities would be spatially prominent in the center of the view toward the transmission interconnection. The scale of the proposed structures would be co-dominant with the existing landform of the valley floor and similar to the existing transmission infrastructure. As a result, the proposed transmission interconnection facilities would appear co-dominant with both the existing landforms and built features.

View Blockage

From KOP 6 the proposed project structures (lower quality landscape features) would partially obscure the Coast Range and sky in the background (to the west). However, this additional view impairment would represent only a slight increase in the blockage of Coast Range views when compared to the existing transmission lines, utility lines, and Tracy Substation. Therefore, the resulting view blockage caused by the proposed project would be low.

Overall Visual Change

From KOP 6, the overall visual change caused by the proposed project would be low-to-moderate, reflecting the low-to-moderate visual contrast that would result from the project's co-dominant structures, combined with the project's low degree of view blockage of higher quality landscape features (sky and Coast Range).

Visual Impact Significance

When considered within the context of the overall moderate visual sensitivity of the existing landscape and viewing characteristics, the low-to-moderate visual change that would be perceived from KOP 6 would cause an adverse but not significant visual impact.

Linear facilities

The visual impact of the electrical transmission interconnection is discussed above under KOP 6.

The proposed underground 20-inch natural gas supply line would not be visible following installation except for an occasional warning marker and would not result in adverse visual impacts. However, the gas pipeline would include an aboveground gas metering station at the interconnection with the PG&E gas pipeline. While the various components of the metering station (several aboveground pipeline segments, valves, and a small structure for controls) would appear industrial in character, in the context of the existing PG&E gas compressor station, which is the proposed location of the gas metering station, the new structures would be minimally noticeable and would not result in significant visual impacts. The same conclusion would also apply to gas pipeline alternative 2C, which would also include a metering station at the existing PG&E gas compressor station. Alternatives 2D and 2E would result in the establishment of the metering station near the Delta Mendota Canal, southwest of the proposed project site. These sites would have minimal public visual access and would not be prominent in views from any nearby roads including Mountain House Road. The resulting visual impacts from these alternatives would not be significant.

The proposed 2.1-mile, 24-inch underground water supply pipeline (Route 3E) and two alternatives (Routes 3A and 3D) would require a water pump station at the starting point at BBID Canal 45 which would be located to the west of the proposed project site in an area with minimal public visual access (adjacent to the California Aqueduct). The resulting visual impacts would not be significant due to the minimal visibility of the pump station. However, Alternative Route 3B would require the installation of a pump station adjacent to Mountain House road at the crossing of Canal 45. This facility would be highly visible in the foreground of views from Mountain House and would result in a significant visual impact when viewed from Mountain House Road if not properly screened by vegetation. However, effective implementation of staff's additional Mitigation Measure 15 through Condition of Certification **VIS-3** would reduce the resulting adverse visual impact to a level that would not be significant.
In addition to the use of raw water, two alternative pipeline routes could convey reclaimed water from the future Mountain House Community Services District waste water treatment plant which would be located near a branch of the Old River. Each alternative would require the installation of a pump station adjacent to the treatment plant and the installation of an underground 24-inch pipeline. The pipeline would be underground and would not result in adverse visual impacts. Also, within the visual context established by the wastewater treatment plant that the pump station would be adjacent to, the pump station would not result in significant visual impacts.

Lighting

The proposed project would be located in a rural agricultural area, which has relatively minimal existing night lighting except for clusters of lights at various infrastructure facilities in the region (Tracy Substation, Tracy Pumping Plant, the PG&E gas compressor station, and the Skinner fish screening facility). Although the proposed project site is currently devoid of night lighting, Tracy Substation, located immediately west of the project site, is a prominent source of night lighting in the project vicinity. Night lighting from Tracy Substation is visible from project vicinity roadways including Mountain House, Kelso, and Byron Bethany Roads. The other principal source of night lighting in the immediate project vicinity is the lighting associated with vehicle headlights on Byron Bethany Road.

The proposed project would require nighttime lighting for operational safety and security though the project would not be required to have FAA-style red, flashing warning lights on the HRSG stacks. Exterior lights would be hooded and directed onsite (EAEC 2001a, AFC p. 8.11-15). High illumination areas not occupied on a regular basis would be provided with switches or motion detectors to light these areas only when occupied. Also, non-glare fixtures would be used (EAEC 2001a, AFC p. 8.11-22).

However, given the lack of existing lighting at the project site and the close proximity of the site to Byron Bethany Road relative to other sources of light in the area (Tracy Substation), the proposed project lighting has the potential to change the character of the existing landscape at night both during construction and operation of the project. Project night lighting would be most visible from Mountain House Road (KOPs 1 and 2), Byron Bethany Road (KOP 5), and Kelso Road (KOPs 4 and 6) where views of the site are open and unobstructed with no intervening structures or light sources. Even shielded lighting elements could create significant light and glare impacts as a result of indirect lighting of project structures and backscatter. The potential for glare or nighttime distraction is of particular concern given the undivided nature of Byron Bethany Road and the high rates of travel speed typically observed.

Visible Plumes

Staff conducted an independent modeling analysis of project vapor plumes associated with the proposed cooling tower and heat recovery steam generators (HRSGs) exhaust stacks (CEC/Walters 2001). In order to model the cooling tower and HRSG plumes, staff used the following information provided by the applicant: (a) Data Responses #'s 114 to 120 (EAEC 2001n, pp. 21-42; EAEC 2001p, pp. 72-76; and EAEC 2001ff, pp. 4-6), and (b) Revised Data Responses #117 and #119 (EAEC 2001gg, pp. 1-6). As shown in **Table 2** below, a high frequency of plume formation would occur as a result of the proposed project.

With duct firing from 10 am to 8 pm, the unabated HRSG plume would occur 21% of all hours and 42% of seasonal daylight hours (seasonal daylight hours are those daylight hours during the months of November through April when conditions conducive to plume formation are most prevalent). The unabated cooling tower plume would occur approximately 24% of all hours and 33% of all seasonal daylight hours.

It should be noted that the HRSG and cooling tower modeling results reflect the applicant's assertion that duct firing will normally occur during the hours of 10 am and 8 pm. The cooling tower and HRSG plume frequencies would be higher if duct firing were to occur beyond those hours and the HRSG plume frequencies would be higher still when power augmentation is used.

Table 2
Staff Predicted Hours with Visible Plumes
Tracy/Brentwood 1997 to 1999 Meteorological Data

Measurement Period	Available Hours	Unabated HRSG With Duct Firing 10 am to 8 pm		Unabated Cooling Tower	
		Total	Percent	Total	Percent
All Hours	26,280	5,578	21.2%	6,426	24.4%
Daylight Hours	13,374	2,627	19.6%	2,154	16.1%
Seasonal Daylight Hours	6,000	2,541	42.4%	1,965	32.8%
Seasonal Daylight No Rain No Fog Hours	Data Not Available	Data Not Available	Data Not Available	Data Not Available	Data Not Available
Seasonal = November through April					

Table 3 provides the plume dimensions for the 10% frequency plume during all hours and seasonal daylight hours. As shown in **Table 3**, the resulting vapor plumes from both the cooling tower and HRSG stacks would be quite large in terms of length, height, and width. Plumes of this magnitude would dominate the visual setting when viewed from numerous vantagepoints within the relatively flat regional terrain.

Table 3
10th Percentile Visible Plume Dimensions – CSVP Model Results
Tracy/Brentwood 1997 – 1999 Meteorological Data

Measurement Period And Parameter	Unabated HRSG With Duct Firing 10 am to 8 pm	Unabated Cooling Tower
All Hours		
Length (ft)	905	6,426
Height (ft)	508	882
Width (ft)	89	397
Seasonal Daylight Hours		
Length (ft)	794	3,264
Height (ft)	823	3,254
Width (ft)	134	446
HRSG data is for each of three separate HRSG exhaust plumes		

The high frequency and large sizes of visible plumes that would occur at the project site would cause a noticeable and persistent change in the landscape character and degradation of visual quality. The plumes would also cause intermittent view blockages of Brushy Peak and Mount Diablo. The resulting visual impacts would be adverse and significant.

CONSIDERATION OF IMPACTS IN RELATION TO CEQA SIGNIFICANCE CRITERIA

This analysis considered the potential impacts of the proposed project in relation to the four significance criteria for visual resource impacts listed in Appendix G of the CEQA Guidelines, under Aesthetics, specified below.

1. **Would the project have a substantial adverse effect on a scenic vista?**

Scenic vistas in the project region would be available from Brushy Peak (approximately 8 miles to the west) and Mount Diablo (approximately 20 miles to the northwest). However, at these substantial viewing distances, the proposed structures would not be prominent features in the landscape and would not cause significant visual impacts. Also, views from Brushy Peak would also encompass the numerous intervening wind turbines between Brushy Peak and the project site. However, the project's vapor plumes would be prominent features in the view from Brushy Peak due to the high frequency of plume occurrence and substantial size. The resulting visual impact on vista views would be significant.

Panoramic views are also available to nearby residents and motorists on project vicinity roads. The project would introduce prominent industrial structures into these panoramic landscapes and would cause view blockage of higher quality visual features, resulting in a significant visual impact. Also, the project's vapor plumes would be prominent features in the panoramic views from nearby residences and project vicinity roads due to the high frequency of occurrence and substantial size of plumes. The resulting visual impact on local panoramic views would be significant.

2. **Would the project substantially damage scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a state scenic highway?**

Although the proposed structures are located within the viewsheds of two county-designated scenic routes, they are not located within the viewshed of a state scenic highway nor would they damage the types of resources specified in this criterion. Therefore, project structures would not result in significant visual impacts under this criterion. However, the project's vapor plumes would be noticeable from I-580, which is a state eligible scenic route and is located approximately four miles south of the project site. The proposed project's unabated vapor plumes would be prominent and persistent features in views from I-580, resulting in a significant visual impact under this criterion.

3. **Would the project substantially degrade the existing visual character or quality of the site and its surroundings?**

As discussed in a previous section of this analysis, the proposed project would introduce prominent structures of industrial character into the foreground to middleground of views from nearby residences and roadways. The resulting visual change would range from low-to-moderate to high depending on viewpoint location. Viewers on adjacent roads and at nearby residences would experience a high level of visual degradation and a significant visual impact under this criterion. Also, the proposed project's unabated vapor plumes would be prominent and persistent features in the views from local and regional roads and nearby residences, resulting in a significant visual impact under this criterion.

4. **Would the project create a new source of substantial light or glare that would adversely affect daytime or nighttime views in the area?**

The project has the potential to create a new source of substantial light that would adversely affect nighttime views in the area and result in a significant visual impact under this criterion.

CUMULATIVE IMPACTS

Cumulative impacts to visual resources could occur where project facilities or activities (such as construction) occupy the same field of view as other built facilities or impacted landscapes. It is also possible that a cumulative impact could occur if a viewer's perception is that the general visual quality of an area is diminished by the proliferation of visible structures (or construction effects such as disturbed vegetation), even if the new structures are not within the same field of view as the existing structures. The significance of the cumulative impact would depend on the degree to which (1) the viewshed is altered; (2) visual access to scenic resources is impaired; (3) visual quality is diminished; or (4) the project's visual contrast is increased.

Staff has identified one other planned project in the viewshed which, when analyzed with the proposed project, may lead to cumulative impacts. The project is he Mountain House new community which is to be developed over the next 20 to 40 years and would be a mixed-use suburban community bounded by the San Joaquin County Line on the west, the Old River on the North, Mountain House Parkway/Patterson Pass Road on the east and I-205 on the south. The full extent of the Mountain House development is not presently known, but depending on the density of the development and its proximity to both Byron Bethany Road and the Alameda/San Joaquin County Line, which is a middleground viewing distance (approximately 1.0 mile) from the proposed project site, cumulative visual impacts could occur. This conclusion is based on the likelihood that both the proposed project and elements of the Mountain House Project would be visible in the same field of view of motorists on Byron Bethany Road and potentially, Kelso Road. The impact could be characterized as a change in the rural agricultural visual character to that of a suburban mixed-use and highly modified landscape. Though the likelihood of a cumulative visual impact is high, the significance of the impact cannot be determined at this time.

In addition, the proposed project would be added to a landscape that is already heavily impacted by energy infrastructure including the very industrial appearing Tracy Substation located on Mountain House Road across from the proposed project. The proposed project would also contribute additional lighting impacts to a nighttime landscape that is already substantially impacted by the unshielded lights of Tracy Substation, thus, contributing to a significant cumulative visual impact.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows the minority population is less than fifty percent within a six-mile radius of the proposed project (please refer to **Socioeconomics Figure 1** in this Staff Analysis) and Census 1990 information that shows the minority/low income population within the same radius is less than fifty percent. However, there is a pocket of minority persons within a one-mile radius of the project site (north of Byron Bethany Road) that staff has considered for impacts. Based on the visual analysis, staff has concluded that the majority population located north of

Byron Bethany Road in the Livermore Yacht Club community, would not have views of the project and would not experience significant visual impacts.

There are a few dispersed residences north of Byron Bethany Road that would be significantly impacted by the project. However, the significant visual impact that they would experience would be similar to that of other dispersed non-minority residences in close proximity to the project site. Therefore, the minority population located north of Byron Bethany Road would not be disproportionately impacted by the proposed project. Furthermore, with full and effective implementation of the applicant's proposed mitigation measures as augmented by staff's mitigation measures and conditions of certification, the impacts experienced by local residents, including the minority population north of Byron Bethany Road, would be reduced to levels that would not be significant.

FACILITY CLOSURE

There are at least three circumstances in which a facility closure can take place, planned closure, unexpected temporary closure and unexpected permanent closure**.**

Planned closure occurs at the end of a project's life, when the facility is closed in an anticipated, orderly manner, at the end of its useful economic or mechanical life, or due to gradual obsolescence. The closure plan that the project owner is required to prepare will address removal of the power plant structures.

Unexpected 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. No special conditions regarding visual resources are expected to be required to address temporary closure.

Unexpected permanent closure occurs if the project owner closes the facility suddenly and/or unexpectedly, on a permanent basis. This includes unexpected closure where the owner remains accountable for implementing the on-site contingency plan. It can also include unexpected closure where the project owner is unable to implement the contingency plan, and the project is essentially abandoned. The contingency plan that the project owner is required to prepare will address removal of the power plant structures.

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

LOCAL

Table 4 provides a listing of the applicable LORS for the Counties of Alameda, San Joaquin, and Contra Costa. Twenty-seven LORS were found to pertain to the enhancement and/or maintenance of visual quality and the protection of views. Based on staff's preliminary analysis, it appears that the proposed project would be consistent with nineteen of the local policies referenced in Table 4, partially consistent with one

local LORS, and inconsistent with seven local LORS. In all seven cases of inconsistency or partial consistency, either the inconsistencies would not initially produce a significant visual impact, or with full and effective implementation of all mitigation measures and staff's conditions of certification, the impacts causing the inconsistencies would be mitigated to levels that would not be significant. Staff is seeking further clarification from Alameda County on LORS consistency and will incorporate the results of further consultations in the FSA.

Table 4 - Proposed Project's Consistency with Local LORS Applicable to Visual Resources

LORS		Consistency Determination Before Mitigation/ Conditions	Basis for Consistency
Source	**Description of Principles, Objectives, and Policies**		
Alameda County			
Alameda County East County Area Plan	Policy 111 requires that development maximize views of a number of specified "prominent visual features."	NO	The only features listed that are visible from the project area are Mount Diablo and Brushy Peak. For each of these features, there will be a short segment along Byron Bethany Road where the project and these distant landmarks would be in direct alignment. In views toward the west from these segments, the project would be seen in front of the landmark feature, blocking views to the feature. However, the view blockage would be relatively brief as motorists pass these points at high rates of speed. Therefore, the project's inconsistency with this policy would constitute an adverse but not significant visual impact.
Alameda County East County Area Plan	Policy 113 requires the use of landscaping in both rural and urban areas to enhance the scenic quality of the area and to screen undesirable views. Choice of plants should be based on compatibility with surrounding vegetation, drought-tolerance, and suitability to site conditions; and in rural areas, habitat value and fire retardance.	YES	The project would be consistent with this policy in that the project would include landscaping around the periphery of the site (as originally proposed) to screen views of the project facilities. In developing its final landscape plan, the applicant would work with the County to ensure that the plant selections and planting designs meet the County's goals for habitat enhancement, drought tolerance, compatibility with surrounding vegetation, and fire retardance (EAEC 2001a, AFC p. 8.11-25).

Table 4 - Proposed Project's Consistency with Local LORS Applicable to Visual Resources

LORS		Consistency Determination Before Mitigation/ Conditions	Basis for Consistency
Source	**Description of Principles, Objectives, and Policies**		
Alameda County East County Area Plan	Policy 117 requires that utility lines be placed underground whenever feasible. When located above ground, utility lines and supporting structures shall be sited to minimize their visual impact.	PARTIALLY	The 230 kV transmission interconnection would be built overhead rather than underground which is typical for the higher voltage transmission facilities such as that associated with the proposed project. However, in general, it is feasible to construct a 230 kV transmission line underground. Therefore, absent a feasibility study for the project site that demonstrates undergrounding the transmission line would not be feasible, the proposed project would be inconsistent with this aspect of Policy 117. Since, the proposed aboveground interconnection would be of short length (0.5 mile) and would be located in an area where transmission infrastructure is a prominent feature in the landscape, the location of the line would minimize the resulting visual impact, which would be adverse but not significant. The proposed project would be consistent with this aspect of Policy 117. Overall, the project impacts causing this partial inconsistency would not be significant.
	Policy 197 requires that the County manage development and conservation of land in East County scenic highway corridors to maintain and enhance scenic values.	NO	There will be two brief segments along Byron Bethany Road where the project would appear to pass in front of Mount Diablo and Brushy Peak as viewed by westbound motorists. Both of these features are notable regional landmarks that are visible from this county-designated scenic highway. However, this view blockage would be relatively brief as motorists pass these points at high rates of speed. Therefore, the project's structural inconsistency with this policy would constitute an adverse but not significant visual impact. Also, if the proposed landscaping / screening plan as augmented by staff's Condition of Certification VIS-3 is effectively implemented in a timely manner, the resulting visual impact would be mitigated to a level that is not significant. Similarly, the proposed project's vapor plumes would also detract from the scenic values experienced along the Byron Bethany Road, resulting in an inconsistency with Policy 197. However, with effective and timely implementation of staff's Condition of Certification VIS-7, project plumes would be mitigated to a level that would not be significant.

Table 4 - Proposed Project's Consistency with Local LORS Applicable to Visual Resources

LORS		Consistency Determination Before Mitigation/ Conditions	Basis for Consistency
Source	**Description of Principles, Objectives, and Policies**		
Alameda County East County Area Plan	Policy 264 states that new developments are to locate utility lines underground, whenever feasible.	NO	The 230 kV transmission interconnection is proposed to be built overhead rather than underground, which is typical for the higher voltage transmission facilities such as that associated with the proposed project. However, in general, it is feasible to construct a 230 kV transmission line underground, particularly for relatively short distances (such as the proposed 0.5-mile interconnection). Therefore, absent a feasibility study for the project site that demonstrates undergrounding the transmission line would not be feasible, the proposed project would be inconsistent with this aspect of Policy 264. Since the proposed aboveground interconnection would be of short length and would be located in an area where transmission infrastructure is a prominent feature in the landscape, the location of the line would minimize the resulting visual impact, which would be adverse but not significant. Therefore, the project's inconsistency with Policy 264 would not constitute a significant visual impact.
Alameda County General Plan Scenic Route Element Principles	Principle: Provide a continuous, convenient system of scenic routes. Principle: Establish efficient and attractive connecting links. Principle: Provide for unimpeded pleasure driving. Principle: Coordinate scenic routes and recreation areas. Principle: Guide and control preservation and development of scenic routes through legislative standards.	YES	The proposed project does not specifically impede the implementation of any of the referenced principles.

Table 4 - Proposed Project's Consistency with Local LORS Applicable to Visual Resources

LORS		Consistency Determination Before Mitigation/ Conditions	Basis for Consistency
Source	**Description of Principles, Objectives, and Policies**		
Alameda County General Plan Scenic Route Element Policies	Policy: Provide for normal uses of land and protect against unsightly features.	NO	The proposed project site has historically been used for agriculture. The proposed project would discontinue the historical use and introduce prominent structures of substantial mass and industrial character. The project would also introduce substantial vapor plumes into the viewshed. These project aspects would result in adverse and significant visual impacts, which would be inconsistent with this policy. However, if the applicant is able to demonstrate that staff's Conditions of Certification VIS-1 through VIS-7 can be fully and effectively implemented along with the project's and staff's mitigation measures, the project's visual impacts would be mitigated to levels that would not be significant. With effective and timely mitigation, the project could be brought into consistency with this policy. Without effective and timely mitigation, the project's inconsistency with this policy would constitute a significant visual impact
	Policy: Locate transmission towers and lines outside of scenic route corridors.	NO	The proposed project (including the transmission interconnection) would be located within the 1,000-foot wide Mountain House scenic corridor so it would not be consistent with this policy. However there is considerable existing utility and energy infrastructure within the adjacent scenic corridors, which establishes a technological and industrial character within the landscape. The visual impact resulting from the presence of the proposed transmission line interconnection would not be significant.

Table 4 - Proposed Project's Consistency with Local LORS Applicable to Visual Resources

LORS		Consistency Determination Before Mitigation/ Conditions	Basis for Consistency
Source	**Description of Principles, Objectives, and Policies**		
	Policy: Establish architectural and site design review.	YES	The applicant has committed to working with the County of Alameda to ensure that various project design elements (landscaping, project heights, colors, and towers) meet County Goals (EAEC 2001a, AFC p. 8.11-25).
	Policy: Use landscaping to increase scenic qualities of scenic route corridors.	NO	The proposed project's landscaping and screening plan, as augmented by staff's Condition of Certification VIS-3, would ensure that the proposed project's visual impacts do not significantly impact scenic qualities experienced from the adjacent scenic routes. However, the proposed landscaping would not increase scenic quality compared to existing conditions and the residual visual impact would still be adverse. The proposed project's inconsistency with this policy would not constitute a significant visual impact.
Alameda County General Plan Scenic Route Element Policies	Policy: Landscape all properties and streets.	YES	The proposed project includes landscaping and vegetative screening.
	Policy: Encourage owners of large holdings to protect and enhance areas of scenic value.	NO	The proposed project site does not contain features of scenic value though as a large open parcel, it enables unobstructed views from adjacent roadways to the Coast Range hills to the west and south. There would be two brief segments along Byron Bethany Road where the project would appear to pass in front of Mount Diablo and Brushy Peak as viewed by westbound motorists. Both of these features are notable regional landmarks of scenic value that are visible from this county-designated scenic highway. However, this view blockage would be relatively brief because motorists pass these points at high rates of speed. Therefore, the project's inconsistency with this policy would constitute an adverse but not significant visual impact.
San Joaquin County			
San Joaquin County General Plan: Community Organization and Development Pattern	Objective: *To create a visually attractive county.* • Policy 11: Development should complement and blend in with its setting.	YES	*Policy 11:* The proposed reclaimed water line would be underground and would not affect the existing landscape. The pump station associated with the reclaimed water line would be located adjacent to the future Mountain House Community Services District wastewater treatment plant and would appear consistent with that facility.

Table 4 - Proposed Project's Consistency with Local LORS Applicable to Visual Resources

LORS		Consistency Determination Before Mitigation/ Conditions	Basis for Consistency
Source	**Description of Principles, Objectives, and Policies**		
	• Policy 12: Aesthetics should be considered when reviewing development proposals.	YES	*Policy 12:* The proposed project's potential impact on local and regional visual resources was considered in both the project proponent's application presented to the Commission and in staff's evaluation of the proposed project.
San Joaquin County General Plan: Public Facilities	Objective: *To protect diverse resources upon which recreation is based, such as waterways, marshlands, wildlife habitats, unique land and* ***scenic features****, and historical cultural sites.* • Policy 23: Scenic corridors along recreation travelways and scenic routes shall be protected from unsightly development.	YES	The proposed reclaimed water line would be underground and would not adversely affect views from adjacent roads. The pump station associated with the reclaimed water line would be located adjacent to the future Mountain House Community Services District wastewater treatment plant and would appear consistent with that facility. Also, visual impacts resulting from project construction would be temporary and not significant.
San Joaquin County General Plan: Open Space	Objective: *To preserve open space land for the continuation of commercial agricultural and productive uses, the enjoyment of* ***scenic beauty*** *and recreation, the protection and use of natural resources, and for protection from natural hazards.* • Policy 11: Outstanding scenic vistas shall be preserved and public access provided to them whenever possible.	YES	*Policy 11:* Due to the underground nature of the proposed reclaimed water pipeline, there would be no adverse impact on any outstanding scenic vista. Also, the pump station associated with the reclaimed water line would be located adjacent to the future Mountain House Community Services District wastewater treatment plant and would not affect scenic vistas or access to scenic vistas.
	• Policy 13: Development proposals along scenic routes shall not detract from the visual and recreational experience.	YES	*Policy 13:* The temporary visual impact during construction of the underground pipeline would not significantly detract from the visual experience along adjacent roads and travelways. Longer-term, the pump station would be located at the future Mountain House Community Services District wastewater treatment plant and would not detract from visual and recreational experiences. The buried pipeline would not have a substantial aboveground presence and would not detract from the visual experience along adjacent roads.

Table 4 - Proposed Project's Consistency with Local LORS Applicable to Visual Resources

LORS		Consistency Determination Before Mitigation/ Conditions	Basis for Consistency
Source	**Description of Principles, Objectives, and Policies**		
San Joaquin County General Plan: Air Quality	Objective: *To protect public health, agricultural crops, **scenic resources**, and the built and natural environments from air pollution.* • Policy 1: San Joaquin County shall meet and maintain all State and national standards for air quality.	YES	The pump station and underground pipeline would not adversely affect existing State and national air quality standards and thus, would not adversely affect county scenic resources.
General Plan: Water Resources and Quality	Objective: *To recognize the surface waters of San Joaquin County as resources of State and national significance for which environmental and **scenic values** must be protected.* • No specific policy statements	YES	The pump station to be located at the future wastewater treatment plant and underground pipeline would not impact the scenic values of any surface waters.
Contra Costa County			
Contra Costa County General Plan, Transportation & Circulation Element, Scenic Routes	Policy 5-34: Scenic corridors shall be maintained with the intent of protecting attractive natural qualities adjacent to various roads throughout the county.	YES	The proposed project would include the construction of a reclaimed water pipeline and a water supply pipeline. The reclaimed water line would include a segment adjacent to Byron Highway in Contra Costa County, which is a county-designated scenic route. Water Supply Alternative 3A would be located adjacent to Byron Highway. Both pipelines would be underground facilities and would have no long-term visual impacts on the scenic route or scenic views from the highway. As a best management practice (BMP), the project would also include filter/silt barriers in close proximity to the highway. However, these facilities would not adversely affect scenic views from the highway.
	Policy 5-36: Scenic views observable from scenic routes shall be conserved, enhanced, and protected to the extent possible.	YES	See Policy 5-34 above.
	Policy 5-42: Provide special protection for natural topographic features, aesthetic views, vistas, hills and prominent ridgelines at "gateway" sections of scenic routes.	YES	See Policy 5-34 above.

Table 4 - Proposed Project's Consistency with Local LORS Applicable to Visual Resources

LORS		Consistency Determination Before Mitigation/ Conditions	Basis for Consistency
Source	Description of Principles, Objectives, and Policies		
	Policy 5-43: Aesthetic design flexibility of development projects within a scenic corridor shall be encouraged.	YES	See Policy 5-34 above.

RESPONSE TO COMMENTS

PUBLIC COMMENTS

G&DK-5: *Besides the plant itself being a visual eyesore, there is no landscaping on earth that would conceal the monstrosity of this plant. This is one more reason that this is not an appropriate placement of this plant. It would be visible from any direction for miles. How is it possible to place this project along designated scenic roads?*

Response: The impact portion of the Visual Resources section of the PSA concludes that significant adverse visual impacts would result from the proposed project. However, with full and effective implementation of the applicant's proposed mitigation measures, staff's additional mitigation measure, and staff's proposed Conditions of Certification **VIS-1** through **VIS-10**, these impacts would be reduced to a level that would not be significant. Of critical importance is the implementation of effective vegetative screening of the project facilities as illustrated in **Visual Resources Figures 2C, 3C, 4C, 5C, 6C, and 7C**. Of equal importance is achievement of project screening within the 5-year time frame specified in Visual Resources Condition of Certification VIS-3. With full and effective implementation of the referenced mitigation measures and conditions of certification, and within the existing landscape context of substantial energy infrastructure, the residual impact on the scenic corridor would be adverse but not significant.

G&DK-7: *How brightly lit is a plant of this magnitude?*

Response: The proposed project has the potential to be very brightly lighted at night. However, standard CEC conditions of certification require the applicant to control lighting in such a way that night lighting does not cause a significant visual impact.

G&DK-19: *No tree or landscaping can hide the enormous size of the plant. Our visual quality will be permanently diminished and our view of Clifton Court Forebay will be gone.*
Response: Please see Response to Comment G&DK-5 above.

AGENCY COMMENTS

On October 4, 2001, staff received a letter from Alameda County that included comments from the Alameda County Community Development Agency regarding visual impact mitigation. The County requested that the Energy Commission impose conditions of certification that would require the applicant to obtain County approval of a visual resources "program" prior to issuance of building and grading permits. The County provided suggested specifications for the various elements of this visual resources program, such as trees and shrubs, paint colors, and lighting.

Response: Staff recommended conditions of certification address color and texture treatments for project structures (VIS-2), landscaping and structural screening (VIS-3), and lighting control (VIS-4).

MITIGATION

APPLICANT'S PROPOSED MITIGATION MEASURES

The applicant has proposed fourteen (14) mitigation measures to be incorporated into the project design to minimize visual impacts associated with the operation of the facility:

1. Creation of a 50-foot setback area between the edge of Mountain House Road and the project fence to provide spatial separation between the project and the road and to provide ample space for installation of landscaping. The landscape treatment along Mountain House Road will likely consist of formal plantings of a variety of shrub species to create a hedge along the edge of the road, backed up by plantings of informal groupings of tall evergreen trees to provide screening of the plant's taller elements. However, it should be noted that the landscaping and screening described here may change with the impending revisions to the applicant's landscape plan.
2. Placement of the water tanks, administration building, and other smaller structures on the western edge of the site to create a transition in scale between the corridor along Mountain House Road and the plant's taller features.
3. Placement of landscaping consisting of informal groupings of fast-growing evergreen trees along the northern, eastern, and southern edges of the site to screen the lower portions of the project's facilities and to visually integrate the facility into the landscape.
4. Color treatment of fences to blend with the surrounding environment.
5. Minimal signage and construction of project signs using non-glare materials and unobtrusive colors. The design of any signs required by safety regulations will need to conform to the criteria established by those regulations.
6. Minimization of lighting to only those areas required for safety, security, or operations, and shielding of lighting from public view to the extent possible. Timers and sensors will be used to minimize the time that lights are on in areas where lighting is not normally needed for safety, security, or operation.

7. Direction and shielding of lighting to reduce light scatter and glare. Highly directional light fixtures will be used.
8. At present, the applicant is proposing to use a palette of neutral gray tones for the project structures. If Alameda County and the CEC feel a need to evaluate color issues further, additional color studies can be conducted to refine the color scheme to maximize the visual integration of project facilities into their landscape backdrop.
9. Design and installation of temporary cyclone fencing around the laydown area adjacent to the plant to reduce the visibility of construction period activities.
10. The transmission line structures used will be tubular steel with a neutral gray finish.
11. Non-specular conductors will be used.
12. Insulators will be non-reflective and non-refractive.
13. After construction, ground surfaces will be restored to their original condition, and any vegetation that had been removed during the construction process will be replaced.
14. Equipment in the gas metering and raw water pump stations will be painted earth-tone colors selected to maximize their visual integration into their backdrops.

ADDITIONAL MITIGATION PROPOSED BY STAFF

Energy Commission staff generally agrees with the applicant's proposals. However, staff's position is that some of these proposals need to be more precisely developed and in some cases expanded in conditions of certification. The following paragraphs discuss additional staff-proposed measures to mitigate project impacts.

Mitigation of Impacts of Proposed Structures

As presently proposed, the project's structures would result in significant visual impacts when viewed from adjacent roads and nearby residences (as illustrated in views from KOPs 1 through 5). Staff has proposed Mitigation Measure 15 to enhance the effectiveness of the applicant's proposed landscaping plan for project screening.

The project owner shall provide landscaping that is effective in screening the proposed project (including the proposed power plant and all aboveground components of the linear facilities) from Byron Bethany Road, Mountain House Road, Kelso Road, and nearby residences. Trees and other vegetation consisting of informal groupings of fast-growing evergreen trees must be strategically placed and of sufficient density and height to fully screen the majority of the complex, industrial-appearing structural forms within five (5) years of completion of project construction as illustrated in **VISUAL RESOURCES Figures 2C, 3C, 4C, 5C, 6C, and 7C**. Also, the perimeter fenceline must be brought inside the treeline in order to obscure the fence (see also Condition of Certification **VIS-3**).

As shown in **VISUAL RESOURCES Figures 2C, 3C, 4C, 5C, 6C, and 7C,** at maturity, the proposed vegetative screening would substantially obscure from view most of the project components. The prominent vegetation would appear similar to a windrow along an agricultural field, which is a common appearance in agricultural areas. If Mitigation Measure 15 is feasible and the applicant is able to achieve its full and effective

implementation, along with the 14 applicant-proposed mitigation measures, and staff-proposed Conditions of Certification **VIS-1** through **VIS-6** and **VIS-10**, visual impacts resulting from project structures would be reduced to levels that would not be significant.

It is important to note that Mitigation Measure 15 would require that full screening be achieved in 5 years rather than the 20 years proposed by the applicant.

It should also be noted that biology staff of the CEC, CDFG, and USFWS are concerned about potential biological impacts of landscape screening . To address this issue, the applicant is preparing a revised landscaping plan If implementation of the revised landscape plan would result in less than full and timely implementation of staff's proposed Mitigation Measure 15, or if Mitigation Measure 15 proves not to be feasible, significant visual impacts from the proposed project structures would occur.

Mitigation of Project Lighting Impacts

As previously discussed, the proposed project lighting has the potential to change the character of the existing landscape at night both during construction and operation of the project and could result in significant visual impacts to adjacent roads and nearby residences. Therefore, staff proposes Mitigation Measure 16 to mitigate project night lighting impacts.

The project owner shall design and install all lighting such that light bulbs and reflectors are not visible from public viewing areas and illumination of the vicinity and the nighttime sky is minimized during both project construction and operation (see also Condition of Certification **VIS-4**).

Full and effective implementation of Mitigation Measure 16 and Condition of Certification **VIS-4** would minimize lighting and keep lighting impacts to less than significant levels.

Mitigation of Impacts of Visible Plumes

The high frequency of plume occurrence and large sizes of the plumes that would form would cause significant visual impacts when viewed within both the immediate project vicinity and greater project region. For this reason, staff has concluded that plume abatement should be implemented for this project. With effective implementation of the plume abatement procedures described below in Mitigation Measures 17 and 18, plume formation would be sufficiently infrequent (less than 10% of seasonal daylight, no-fog, no-rain hours) such that the resulting visual impact would not be significant.

The project owner shall abate the HRSG vapor plume frequencies through the use of an economizer bypass, or equivalent means, to reduce predicted plume frequency to less than 10% of seasonal (i.e. November through April) daylight no fog/no rain hours. An automated control system will be used to ensure that plumes are abated to the maximum extent possible when raising the exhaust temperature to the stipulated design point (see also Condition of Certification **VIS-7**).

The project owner shall abate the cooling tower visible vapor plume frequencies through the use of a plume abated wet/dry cooling tower, or equivalent means, to reduce predicted plume frequency to less than 10% of seasonal (i.e. November through April)

daylight no fog/no rain hours. An automated control system shall be used to ensure that plumes are abated to the maximum extent possible for the stipulated design point (see also Condition of Certification **VIS-8**).

Staff analyzed potential plume abatement for the cooling tower and HRSG using the following assumptions:

- Cooling tower abated to 38°F and 80% relative humidity as is currently proposed by Calpine for Russell City. Cooling tower operating data provided for Russell City has been used in this modeling analysis.

- HRSG with economizer bypass that will allow the stack temperature to be raised to a minimum of 270°F. Again, this is the same as the HRSG plume mitigation currently proposed by Calpine for Russell City.

Staff understands that the specific HRSG abatement design assumptions do not reflect the EAEC's high-powered density design; however, the Applicant did not respond to staff's request to provide specific HRSG abatement information (CEC 2001i, p. 5; EAEC 2001z, pp. 1-3), so staff has used the Russell City abatement design as a starting point in the HRSG abatement approach for this project.

While the specific plume abatement measures evaluated by staff for the PSA, particularly those for the HRSG, may not be specifically applicable to the EAEC design, it is important that the project achieve a plume frequency goal of less than 10% of seasonal daylight no fog/no rain hours.

The plume frequency results for the modeled plume abated HRSG and cooling tower are presented in Table 5 below. As shown in Table 5, the assumed plume abated designs would substantially reduce the frequency of plume occurrence. The abated HRSG plume with duct firing and power augmentation would have an 18% frequency of occurrence for seasonal daylight hours compared to 42% for the unabated plume. The abated HRSG plumes with duct firing only and without duct firing or power augmentation would have 8.2% and 1.67% frequencies of occurrence respectively. The frequency of occurrence of the abated cooling tower plume would be reduced to approximately 10%, from 33% for the unabated condition.

It should be noted that 805 of the 1,102 seasonal daylight hours (77%) that are predicted to have plumes during mitigated worst case operation (abated HRSG with duct firing and power augmentation) have ambient relative humidities at or above 95%. Therefore, it is assumed that many of these hours would be during fog or rain hours that are not considered hours with the potential to cause substantial visual contrast from visual water vapor plumes. Additionally, it is reasonable to expect that maximum duct firing and power augmentation would not generally occur during the cold morning hours when plumes are predicted to occur most frequently. Therefore, staff expects that the actual operating plume frequency with the assumed plume abated method would be reduced to well below 10% of seasonal daylight hours and 10% of seasonal daylight no-fog, no-rain hours from the 18.37% for seasonal daylight hours shown in Table 5.

VISUAL RESOURCES: Table 5
Staff Predicted Hours with Visible Plumes – Plume Abated Designs
Tracy/Brentwood 1997 to 1999 Meteorological Data

Measurement Period	Available Hours	Abated HRSG With Duct Firing and Power Augmentation		Abated Cooling Tower	
		Total	Percent	Total	Percent
All Hours	26,280	4,147	15.78%	2,027	7.71%
Daylight Hours	13,374	1,124	8.40%	582	4.35%
Seasonal Daylight Hours	6,000	1,102	18.37%	582	9.70%
		Abated HRSG With Duct Firing Only			
		Total	**Percent**		
All Hours	26,280	1,609	6.12%		
Daylight Hours	13,374	492	3.68%		
Seasonal Daylight Hours	6,000	492	8.20%		
		Abated HRSG Without Duct Firing or Power Augmentation			
		Total	**Percent**		
All Hours	26,280	315	1.20%		
Daylight Hours	13,374	100	0.75%		
Seasonal Daylight Hours	6,000	4100	1.67%		

Mitigation of Impacts in Relation to CEQA Significance Criteria

The proposed project has the potential to cause significant visual impacts with respect to each of the four CEQA significance criteria. Project structures would cause significant visual impacts to scenic vistas and panoramic views from local roads and nearby residences (Criterion 1). Project structures would also degrade the existing character and quality of the site and its surroundings (Criterion 3). Full and timely implementation of staff's previously discussed Mitigation Measure 15 (through Condition of Certification **VIS-3**) would reduce the visual impacts of project structures under Criteria 1 and 3 to levels that would not be significant. However, as previously stated, biology staff of the CEC, CDFG, and USFWS are concerned about potential biological impacts of proposed landscaping To address this issue, the applicant recently submitted a revised landscaping plan, which staff has not yet had time to evaluate. If the revised landscape plan would not result in full and timely implementation of staff's proposed Mitigation Measure 15, or if Mitigation Measure 15 proves not to be feasible, visual impacts from the proposed project structures would be significant under Criteria 1 and 3.

The proposed project's vapor plumes would cause significant visual impacts to scenic vistas and panoramic views from local roads and nearby residences (Criterion 1). Project plumes would also degrade the scenic quality experienced from state eligible scenic highway I-580 (Criterion 2), and would degrade the existing character and quality of the site and its surroundings (Criterion 3). Full and effective implementation of staff's previously discussed Mitigation Measures 17 and 18 (and Conditions of Certification **VIS-7** and **VIS-8** respectively) would reduce the visual impacts under Criteria 1 through 3 to levels that would not be significant.
The project's night lighting has the potential to create a new source of substantial light that would adversely affect nighttime views in the area and result in a significant visual

impact under this criterion. However, the exterior lighting control measures proposed by the applicant and expanded by staff in Mitigation Measure 16 (previously discussed) and Condition of Certification **VIS-4** would ensure that lighting impacts would be less than significant with regard to Criterion 4.

Mitigation of Cumulative Impacts

As previously described, even if the lighting impacts for the proposed project are mitigated as recommended above in Mitigation Measure 16, residual impacts due to the proposed project would occur, contributing to a significant cumulative visual impact. Staff recommends that these impacts be offset by reducing lighting impacts at the adjacent Tracy Substation as described below in Mitigation Measure 19 (see also Condition of Certification **VIS-9**).

The project owner shall have the lighting at Tracy Substation modified such that light bulbs and reflectors are not visible from public viewing areas and illumination of the vicinity and the nighttime sky is minimized. Specific requirements shall include but not be limited to: (a) hoods on all exterior light fixtures to direct light downward and/or toward the area to be illuminated, and (b) the use of switches and/or motion detectors to illuminate only those areas that are occupied.

Environmental Justice

As previously discussed, staff has identified a pocket of minority persons within a one-mile radius of the project site (north of Byron Bethany Road). Staff has concluded that the few dispersed residences north of Byron Bethany Road would experience significant though not disproportionate visual impacts similar to those of other dispersed non-minority residences in close proximity to the project site. Therefore, the minority population located north of Byron Bethany Road would not be disproportionately impacted by the proposed project. With full and effective implementation of the applicant's proposed mitigation measures as augmented by staff's mitigation measures and conditions of certification, the impacts experienced by local residents (including the minority population north of Byron Bethany Road) would be reduced to levels that would not be significant.

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

Staff concludes that without the applicant's proposed mitigation measures and screening plan, and staff's proposed mitigation measures and conditions of certification (below), the proposed project would cause adverse and significant visual impacts. As noted throughout this section, staff has yet to analyze the applicant's revised landscaping plan submitted in November. Staff will evaluate the new landscaping plan and present the results in the Final Staff Assessment. If staff finds that the revised landscape plan would not result in full and timely implementation of staff's proposed landscaping mitigation, or if the mitigation is determined to not be feasible, significant visual impacts from the proposed project structures would remain.
Staff also concludes that in the seven cases of potential inconsistency or partial consistency with applicable laws, ordinances, regulations, and standards, either the

inconsistencies would initially not produce a significant visual impact, or with full, effective, and timely implementation of all mitigation measures and staff's conditions of certification, the impacts causing the inconsistencies would be mitigated to levels that would not be significant.

RECOMMENDATIONS

The Energy Commission should adopt the following conditions of certification if it approves the project.

PROPOSED CONDITIONS OF CERTIFICATION

VIS-1 The project owner shall ensure that visual impacts of project construction are adequately mitigated. To accomplish this, the project owner shall require the following as a condition of contract with its contractors to construct the proposed project:

Protocol: If visible from nearby residences, Byron Bethany Road, Mountain House Road, or Kelso Road, the project site as well as staging and material and equipment storage areas shall be visually screened. All evidence of construction activities, including ground disturbance due to staging and storage areas, shall be removed and remediated upon completion of construction to its pre-construction condition. Any vegetation removed in the course of construction will be replaced on a 1-to-1 in-kind basis. Such replacement planting shall be monitored for a period of three years to ensure survival. During this period, all dead plant material shall be replaced.

The project owner shall submit a plan to the CPM for review and approval and to Alameda, Contra Costa, and San Joaquin counties for review and comment for restoring the surface conditions of any rights of way disturbed during construction of underground pipelines, and staging and storage areas. The plan shall include grading to the original grade and contouring and revegetation.

The project owner shall not implement the restoration plan until receiving written approval from the CPM.

Verification: At least ninety (90) days prior to beginning implementation of the surface restoration, the project owner shall submit the restoration plan to the CPM for review and approval and to Alameda, Contra Costa, and San Joaquin counties for review and comment.

If the CPM notifies the project owner that any revisions of the restoration plan are needed before the CPM will approve the plan, within thirty (30) days of receiving that notification, the project owner shall submit to the CPM a revised plan.

The project owner shall notify the CPM within seven (7) days after completing the surface restoration that it is ready for inspection.

VIS-2 Prior to first turbine roll, the project owner shall treat project structures, buildings, gas metering and pump stations, and fences in appropriate colors or hues that minimize visual intrusion and contrast by blending with the surrounding landscape, and shall treat those items in a non-reflective, appropriately textured finish. A specific treatment plan shall be developed for CEC approval to ensure that the proposed colors do not unduly contrast with the surrounding landscape colors. The plan shall be submitted sufficiently early to ensure that any precolored buildings, structures, and linear facilities will have colors approved and included in bid specifications for such buildings or structures. Prior to submittal of the plan to the Energy Commission, the project owner shall submit the plan to Alameda, Contra Costa, and San Joaquin Counties for review and comment.

Protocol: The treatment plan shall include:

a) specifications, and 11" x 17" color simulations, of the treatment proposed for use on project structures, including structures treated during manufacture;

b) a list of each major project structure, building, tank, and fence specifying the color(s) proposed for each item;

c) samples of each proposed treatment and color on the materials to which they are to be applied;

d) documentation that a non-reflective finish will be used on all project elements visible to the public;

e) a detailed schedule for completion of the treatment; and

f) a procedure to ensure proper treatment maintenance for the life of the project.

After approval of the plan by the CPM, the project owner shall implement the plan according to the schedule and shall ensure that the treatment is properly maintained for the life of the project.

For any structures that are treated during manufacture, the project owner shall not specify the treatment of such structures to the vendors until the project owner receives notification of approval of the treatment plan by the CPM.

The project owner shall not perform the final treatment on any structures until the project owner receives notification of approval of the treatment plan from the CPM.

Verification: At least ninety (90) days prior to ordering the first structures that are color treated during manufacture, the project owner shall submit its proposed plan to

the CPM for review and approval and to Alameda, Contra Costa, and San Joaquin counties for review and comment.

If the CPM notifies the project owner that any revisions of the plan are needed before the CPM will approve the plan, within thirty (30) days of receiving that notification, the project owner shall submit to the CPM a revised plan.

Not less than thirty (30) days prior to the start of commercial operation, the project owner shall notify the CPM that all structures treated during manufacture and all structures treated in the field are ready for inspection.

The project owner shall provide a status report regarding treatment maintenance in the Annual Compliance Report.

VIS-3 The project owner shall provide landscaping that is effective in screening the proposed project (including the water supply alternative 3B pump station) from views from Byron Bethany Road, Mountain House Road, Kelso Road, and nearby residences. Trees and other vegetation consisting of informal groupings of fast-growing evergreen trees must be strategically placed and of sufficient density and height to fully screen the majority of structural forms within five (5) years after first turbine roll, as illustrated in the attached visual simulations of the project at 20 years (presented as **VISUAL RESOURCES Figures 2C, 3C, 4C, 5C, 6C, and 7C**). The perimeter fenceline must be brought inside the treeline in order to obscure the fence.

Protocol: The project owner shall submit a landscaping plan to the CPM for review and approval and to Alameda, Contra Costa, and San Joaquin counties for review and comment. The Plan shall include:

a) 11”x17” color simulations of the proposed landscaping at 5 years as viewed from KOPs 1, 2, 4, and 5; and

b) a detailed list of plants to be used and times to maturity given their size and age at planting;.

The project owner shall not implement the plan until the project owner receives approval of the submittal from the CPM. However, the planting must be completed by start of project operation.

Verification: Prior to first turbine roll and at least ninety (90) days prior to installing the landscaping, the project owner shall submit the landscaping plan to the CPM for review and approval and to Alameda, Contra Costa, and San Joaquin counties for review and comment.

If the CPM notifies the project owner that revisions of the submittal are needed before the CPM will approve the submittal, within thirty (30) days of receiving that notification, the project owner shall prepare and submit to the CPM a revised submittal.

The project owner shall notify the CPM within seven (7) days after completing installation of the landscaping, that the landscaping is ready for inspection.

VIS-4 Prior to first turbine roll, the project owner shall design and install all lighting such that light bulbs and reflectors are not visible from public viewing areas and illumination of the vicinity and the nighttime sky is minimized during both project construction and operation. The project owner shall develop and submit a lighting plan for the project to the CPM for review and approval.

Protocol: The lighting plan shall require that:

a) lighting shall be designed so that during both construction and operation, highly directional, exterior light fixtures are hooded, with lights directed downward or toward the area to be illuminated and so that backscatter to the nighttime sky is minimized. The design of this outdoor lighting shall be such that the luminescence or light source is shielded to prevent light trespass outside the project boundary;

b) high illumination areas not occupied on a continuous basis such as maintenance platforms shall be provided with switches or motion detectors to light the area only when occupied; and

c) a lighting complaint resolution form (following the general format of that in **Visual Resources Appendix VR-2**) shall be used by plant operators, to record all lighting complaints received and to document the resolution of those complaints. All records of lighting complaints shall be kept in the on-site compliance file.

Lighting shall not be installed before the lighting plan is approved.

Verification: At least ninety (90) days before ordering the exterior lighting, the project owner shall provide the lighting plan to the CPM for review and approval and to Alameda, Contra Costa, and San Joaquin counties for review and comment.

If the CPM notifies the project owner that any revisions of the plan are needed before the CPM will approve the plan, within thirty (30) days of receiving that notification the project owner shall submit to the CPM a revised plan.

The project owner shall notify the CPM within seven (7) days of completing exterior lighting installation that the lighting is ready for inspection.

VIS-5 The project owner shall comply with the signage requirements of Alameda, Contra Costa, and San Joaquin Counties. In addition, the project owner shall install minimal signage, which shall be constructed of non-glare materials and unobtrusive colors. The design of any signs required by safety regulations shall conform to the criteria established by those regulations. The project owner shall submit a signage plan for the project to the CPM for review and approval and to Alameda, Contra Costa, and San Joaquin counties for review and comment. The project owner shall not implement the plan until the project owner receives approval of the submittal from the CPM.

Verification: Prior to first turbine roll and at least ninety (90) days prior to installing signage, the project owner shall submit the plan to the CPM for review and

approval and to Alameda, Contra Costa, and San Joaquin counties for review and comment.

If the CPM notifies the project owner that revisions of the plan are needed before the CPM will approve the submittal, within thirty (30) days of receiving that notification, the project owner shall prepare and submit to the CPM a revised submittal.

The project owner shall notify the CPM within seven (7) days after completing installation of signage that they are ready for inspection.

VIS-6 The project owner shall comply with the Alameda County requirements regarding submittal of project plans to the County for design review.

Protocol: The project owner shall submit project plans to the CPM for review and approval and to Alameda County for review and comment.

If the CPM notifies the project owner that revisions of the plans are needed before the CPM will approve the submittal, the project owner shall submit to the CPM revised plans.

The project owner shall not implement the plans until the project owner receives approval of the submittal from the CPM.

Verification: At the time that the project owner submits a particular project plan to the CPM for review and approval, it shall also be submitted to Alameda County for review and comment.

If the CPM notifies the project owner that revisions of a particular plan are needed before the CPM will approve the plan, within thirty (30) days of receiving that notification, the project owner shall submit to the CPM revised plans.

The project owner shall notify the CPM within seven (7) days after completing installation of each project component subjected to local design review.

VIS-7 The project owner shall abate the HRSG visible vapor plumes.

Protocol: The project owner shall abate the frequency of the HRSG vapor plumes as follows:

a) An economizer bypass, or equally effective means, shall be used to reduce predicted frequency of the HRSG exhaust visible vapor plumes to less than 10% of seasonal (i.e. November through April) daylight no fog/no rain hours.

b) An automated control system shall be used to ensure that plumes are abated to the maximum extent possible when raising the exhaust temperature to the stipulated design point.

Verification: At least sixty (60) days prior to erection of the HRSGs, the project owner shall submit to the CPM for review and approval, the specifications of the plume abatement system for the HRSGs and the specifications for the automated control

system and related systems and sensors that will be used to ensure appropriate plume abatement operation for the HRSG plume abatement system.

If the CPM notifies the project owner that any revisions of the specifications are needed prior to CPM approval, within thirty (30) days of receiving that notification, the project owner shall submit to the CPM revised specifications.

The project owner shall monitor the HRSG visible plume frequency during the first year of operation from November 1st to April 30th and provide evidence of compliance (including physical evidence and frequency data), to the CPM within 30 days of the end of the monitoring period. This monitoring requirement shall be in force until there is a body of evidence demonstrating that the automated control system is maintaining compliance with the condition.

VIS-8 The project owner shall abate the cooling tower visible vapor plumes.

Protocol: The project owner shall abate the frequency of the cooling tower visible vapor plumes as follows:

a) A plume abated wet/dry cooling tower, or equally effective means, shall be used to reduce predicted cooling tower visible vapor plume frequency to less than 10% of seasonal (i.e. November through April) daylight no fog/no rain hours.

b) An automated control system shall be used to ensure that plumes are abated to the maximum extent possible for the stipulated design point.

Verification: At least sixty (60) days prior to ordering the cooling tower, the project owner shall submit to the CPM for review and approval the specifications of the plume abatement system for the cooling tower and the specifications for the automated control system and related systems and sensors that will be used to ensure appropriate plume abatement operation for the cooling tower plume abatement system.

If the CPM notifies the project owner that any revisions of the specifications are needed prior to CPM approval, within thirty (30) days of receiving that notification, the project owner shall submit to the CPM revised specifications.

The project owner shall monitor the cooling tower visible plume frequency during the first year of operation from November 1st to April 30th and provide evidence of compliance (including physical evidence and frequency data), to the CPM within 30 days of the end of the monitoring period. This monitoring requirement shall be in force until there is a body of evidence demonstrating that the automated control system is maintaining compliance with the condition.

VIS-9 Prior to first turbine roll, to offset the contribution of the proposed project to cumulative lighting impacts, the project owner shall have the lighting at Tracy Substation modified such that light bulbs and reflectors are not visible from public viewing areas and illumination of the vicinity and the nighttime sky is minimized. To meet these requirements, the project owner shall develop and submit a lighting modification plan for the project to the CPM for review and approval.

Protocol: The lighting plan shall require the following:

a) Exterior light fixtures shall be hooded, with lights directed downward or toward the area to be illuminated and backscatter to the nighttime sky is minimized. The luminescence or light source shall be shielded to prevent light trespass outside the project boundary;

b) High illumination areas not occupied on a continuous basis such as maintenance platforms or the main entrance shall be provided with switches or motion detectors to light the area only when occupied;

c) A lighting complaint resolution form (following the general format of that in Appendix VR-2) shall be used by plant operations, to record all lighting complaints received and document the resolution of those complaints. All records of lighting complaints shall be kept in the on-site compliance file.

If the CPM notifies the project owner that revisions of the plan are needed before the CPM will approve the plan, the project owner shall prepare and submit to the CPM a revised plan.

Lighting modifications shall not be made before the plan is approved. The project owner shall notify the CPM when the lighting modifications have been made and are ready for inspection.

Verification: At least 60 days prior to first electricity generation on the EAEC project, the project owner shall provide the lighting modification plan to the CPM for review and approval.

If the CPM notifies the project owner that any revisions of the plan are needed before the CPM will approve the plan, within 30 days of receiving that notification the project owner shall submit to the CPM a revised plan.

The project owner shall notify the CPM within seven days after completing exterior lighting modifications that the lighting is ready for inspection.

VIS-10 The project owner shall implement project design measures that minimize visual impacts associated with project operation.

Protocol: The project owner shall minimize project operational impacts by implementing the following:

a) The project owner shall create a 50-foot setback area between the edge of Mountain House Road and the project fence to provide spatial separation between the project and the road and to provide ample space for installation of landscaping. The landscape treatment along Mountain House Road shall consist of formal plantings of a variety of shrub species to create a hedge along the edge of the road, backed up by plantings of informal groupings of tall evergreen trees to provide screening of the plant's taller elements.

b) The project owner shall place the water tanks, administration building, and other smaller structures on the western edge of the site to create a transition in scale between the corridor along Mountain House Road and the plant's taller features.

c) The project owner shall install tubular steel transmission line structures with a neutral gray finish.

d) The project owner shall install non-specular conductors.

Verification: At least sixty (60) days prior to first turbine roll, the project owner shall submit to the CPM for review and approval, the specifications for (a) the setback and landscape treatment along Mountain House Road, (b) the tubular steel transmission line structures, and (c) the transmission conductors.

If the CPM notifies the project owner that any revisions of the specifications are needed prior to CPM approval, within thirty (30) days of receiving that notification, the project owner shall submit to the CPM revised specifications.

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APPENDIX VR – 1

EAST ALTAMONT ENERGY PROJECT VISUAL RESOURCES STAFF ASSESSMENT - SUMMARY OF ANALYSIS

(DOES NOT INCLUDE PLUME ANALYSIS)

VIEWPOINT		EXISTING VISUAL SETTING								VISUAL CHANGE					IMPACT SIGNIFICANCE	
				Viewer Exposure												
Key Observation Point (KOP)	Description	Visual Quality	Viewer Concern	Visibility	Distance Zone	Number of Viewers	Duration of View	Overall Viewer Exposure	Overall Visual Sensitivity	Description of Visual Change	Visual Contrast	Project Dominance	View Blockage	Overall Visual Change	Mitigation / Conditions	Impact Significance with Mitigation
KOP 1 **BYRON BETHANY ROAD AT MOUNTAIN HOUSE ROAD** **Figure 2**	View to the south from the intersection of Byron Bethany Road and Mountain House Road, north of the project site.	**Low to Moderate** Foreground to middleground flat agricultural landscape dominated by electric transmission infrastructure and backdropped by the Diablo Range to the south.	**Moderate to High** Motorists on Mountain House Road anticipate a foreground to middleground landscape dominated by energy infrastructure, but with a visible background of distant rolling hills. Any additional blockage of views of surrounding hills would be perceived as an adverse visual change.	**High**	**Foreground**	**High**	**Moderate**	**High**	**Moderate to High**	Addition of prominent geometric forms with horizontal to vertical lines and complex industrial character. Structural mass would be greater than surrounding facilities. Facilities would be visible and co-dominant at this foreground viewing distance.	**High**	**Co-Dominant to Dominant**	**Moderate to High**	**Moderate to High**	**Applicant's Measures & Staff's Conditions: VIS-2 VIS-3 VIS-4**	**Adverse but Not Significant** **(Significant without Mitigation / Conditions)**
KOP 2 **MOUNTAIN HOUSE ROAD** **Figure 3**	View to the north from northbound Mountain House Road, just north of Kelso Road.	**Low to Moderate** Foreground to middleground flat agricultural landscape with a prominent presence of electric transmission infrastructure that does not obscure the distant horizon.	**Moderate** Motorists on Mountain House Road anticipate a foreground to middleground agricultural landscape with prominent energy infrastructure. However, the addition of prominent geometric forms with significant mass that blocks views of the horizon would be would be perceived as an adverse visual change.	**High**	**Foreground**	**Moderate**	**Moderate**	**Moderate to High**	**Moderate**	Addition of prominent geometric forms with horizontal to vertical lines and complex industrial character. Structural mass would be greater than surrounding facilities. Facilities would be visible and co-dominant at this foreground viewing distance.	**High**	**Co-Dominant**	**Moderate**	**Moderate to High**	**Applicant's Measures & Staff's Conditions: VIS-2 VIS-3 VIS-4**	**Adverse but Not Significant** **(Significant without Mitigation / Conditions)**
KOP 3 **MOUNTAIN HOUSE ROAD AT MOUNTAIN HOUSE SCHOOL** **Figure 4**	View to the north from northbound Mountain House Road at Mountain House School.	**Low to Moderate** Foreground to middleground flat agricultural landscape with a prominent presence of electric transmission infrastructure that does not obscure the distant horizon.	**Moderate** Motorists on Mountain House Road anticipate a foreground to middleground agricultural landscape with prominent energy infrastructure. However, the addition of prominent geometric forms with significant mass that blocks views of the horizon would be would be perceived as an adverse visual change.	**Moderate**	**Middleground**	**Moderate**	**Moderate to Extended**	**Moderate**	**Moderate**	Addition of prominent geometric forms with horizontal to vertical lines and complex industrial character. Structural mass would be greater than surrounding facilities. Facilities would be visible and co-dominant at this middleground viewing distance.	**High**	**Co-Dominant**	**Moderate**	**Moderate to High**	**Applicant's Measures & Staff's Conditions: VIS-2 VIS-3 VIS-4**	**Adverse but Not Significant** **(Significant without Mitigation / Conditions)**
KOP 4 **KELSO ROAD (Westbound)** **Figure 5**	View to the northwest from westbound Kelso Road, approximately 0.55 mile southeast of the project site.	**Low to Moderate** Foreground to middleground flat agricultural landscape with numerous electric transmission lines in the middleground of views backdropped by rolling hills and wind turbines.	**Moderate** Westbound motorists on Kelso Road anticipate a foreground to middleground agricultural landscape and the presence of energy infrastructure. However, the addition of prominent geometric forms with complex industrial character would be would be perceived as an adverse visual change.	**High**	**Middleground**	**Low**	**Moderate to Extended**	**Moderate**	**Moderate**	Addition of prominent geometric forms with horizontal to vertical lines and complex industrial character. Structural mass would be greater than surrounding facilities. Facilities would be visible and co-dominant at this middleground viewing distance.	**High**	**Co-Dominant to Dominant**	**Moderate**	**Moderate to High**	**Applicant's Measures & Staff's Conditions: VIS-2 VIS-3 VIS-4**	**Adverse but Not Significant** **(Significant without Mitigation / Conditions)**
KOP 5 **BYRON BETHANY ROAD AT LINDEMAN ROAD** **Figure 6**	View to the west from the intersection of Byron Bethany and Lindeman Roads.	**Moderate** Foreground to middleground flat agricultural landscape with numerous electric transmission lines but backdropped by rolling to angular hills, Brushy Peak, and Mount Diablo which is a visible regional landmark.	**Moderate to High** Motorists on Byron Bethany Road (a County-designated scenic route) anticipate a foreground to middleground agricultural landscape and the presence of energy infrastructure, as well as unobstructed views of the hills beyond and Mount Diablo. Any increase in view blockage or diminishment of visual quality would be perceived as an adverse visual change.	**High**	**Middleground**	**High**	**Extended**	**High**	**Moderate to High**	Addition of prominent geometric forms with horizontal to vertical lines and complex industrial character. Structural mass would be greater than surrounding facilities and would result in blockage of views toward Brushy Peak and Mount Diablo.	**High**	**Co-Dominant to Dominant**	**Moderate to High**	**Moderate to High**	**Applicant's Measures & Staff's Conditions: VIS-2 VIS-3 VIS-4**	**Adverse but Not Significant** **(Significant without Mitigation / Conditions)**
KOP 6 **KELSO ROAD (Transmission Corridor)** **Figure 7**	View to the west from Kelso Road, approximately 0.45 mile east of Mountain House Road.	**Low to Moderate** Foreground to middleground flat agricultural landscape with numerous electric transmission lines in the foreground to middleground of views backdropped by rolling hills and wind turbines.	**Moderate** Westbound motorists on Kelso Road anticipate a foreground to middleground agricultural landscape and the presence of energy infrastructure. However, the introduction of additional energy infrastructure with industrial character into the existing landscape would be would be perceived as an adverse visual change.	**High**	**Foreground**	**Low**	**Extended**	**Moderate to High**	**Moderate**	Addition of prominent linear forms with horizontal to vertical lines. Structural character would be similar to and consistent with the adjacent transmission facilities.	**Low to Moderate**	**Co-Dominant**	**Low**	**Low to Moderate**	**Applicant's Measures & Staff's Conditions: VIS-2**	**Adverse but Not Significant**

APPENDIX VR – 2

LIGHTING COMPLAINT RESOLUTION FORM

East Altamont Energy Center Alameda County, California
Complainant's name and address: Phone number:
Date complaint received: Time complaint received:
Nature of lighting complaint:
Definition of problem after investigation by plant personnel: Date complainant first contacted:
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: Plant Manager's Signature:

(Attach additional pages and supporting documentation, as required.)

APPENDIX VR – 3: VISUAL RESOURCES FIGURES

VISUAL RESOURCES FIGURES 1 THROUGH 7C

WASTE MANAGEMENT

Obed Odoemelam, Ph.D.

INTRODUCTION

Different types of wastes will be generated during the construction and operation of the proposed East Altamont Energy Center (EAEC) and will have to be managed appropriately to minimize the potential for adverse human and environmental impacts. These wastes are designated as hazardous or non-hazardous according to the toxic nature of their respective constituents. This analysis assesses the adequacy of the management plan proposed by the applicant, Calpine D.B.A. East Altamont Energy Center, LLC (or Calpine) for the handling, storage and disposal of these wastes in the amounts estimated for the project. The handling of project's wastewater, for which a National Pollutant Discharge Elimination System (NPDES) permit is required, is discussed in the **Soil and Water Resources** section.

This Energy Commission staff analysis is intended to ensure that all the wastes that are generated during project construction and operation are handled and disposed of according to the applicable laws, ordinances, regulations, and standards (LORS). These LORS are discussed below.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

FEDERAL

Resource Conservation and Recovery Act, RCRA, (42 U.S.C. § 6922)

RCRA establishes requirements for the management of hazardous wastes from the time of generation to the point of ultimate treatment or disposal. Section 6922 requires the generators of hazardous wastes to comply with requirements regarding:

1. Record keeping practices which identify the quantities and disposal of hazardous wastes generated;
2. Labeling practices and use of appropriate containers;
3. Use of a recording or manifest system for transportation; and
4. Submission of periodic reports to the EPA or an authorized state agency.

Title 40, Code of Federal Regulations, section 260

These sections specify the regulations promulgated by the EPA to implement the requirements of RCRA as described above. To facilitate such implementation, the defining characteristics of each hazardous waste are specified in terms of toxicity, ignitability, corrosivity, and reactivity.

STATE

California Health and Safety Code §25100 et seq. (Hazardous Waste Control Act of 1972, as amended).

This act creates the framework under which hazardous wastes must be managed in California. It mandates the State Department of Health Services (now the Department of Toxic Substances Control or DTSC, under the California Environmental Protection Agency, or Cal EPA) to develop and publish a list of hazardous and extremely hazardous wastes, and to develop and adopt specific criteria and guidelines for classifying such wastes. The act also requires all hazardous waste generators to file specific notification statements with Cal EPA and creates a manifest system to be used when transporting such wastes.

Title 14, California Code of Regulations, §17200 et seq. (Minimum Standards for Solid Waste Handling and Disposal)

These regulations specify the minimum standards applicable to the handling and disposal of solid wastes. They also specify the guidelines necessary to ensure that all solid waste management facilities comply with the solid waste management plans of the administering county agency.

Title 22, California Code of Regulations, §66262.10 et seq. (Generator Standards)

These sections establish specific requirements for generators of hazardous wastes with respect to handling and disposal. Under these requirements, all waste generators are required to determine whether or not their wastes are hazardous according to state-specified criteria. As with the federal program, every hazardous waste generator is required to obtain an EPA identification number, prepare all relevant manifests before transporting the waste off-site, and use only permitted treatment, storage, and disposal facilities. Additionally, all hazardous wastes are required to be handled only by registered hazardous waste transporters. Requirements for record keeping, reporting, packaging, and labeling are also established for each generator.

LOCAL

There are no local LORS that would apply to the proposed project.

SETTING

PROJECT AND SITE DESCRIPTION

According to information from the applicant (EAEC 2001a, pages 1-1, 2-1, 8.1-1, 8.4-2, and 8.13-1), the proposed project is a natural gas-fired 1,100 MW facility to be located on approximately 55 acres within a 174- acre parcel of land in northeastern Alameda County near the Contra Costa and San Joaquin County borders. The site is bounded to the north by Byron Bethany Road, to the south by Kelso Road, and to the west by Mountain House Road. It is currently being used for cattle grazing and crop farming, having been used in the past as a dairy farm. The surrounding area is currently used for agriculture and large infrastructure projects, the most important of which include the

Western Area Power Authority's (Western's) Tracy Substation, two pumping stations for the Delta-Mendota Canal and the California Aqueduct, Pacific Gas and Electric's (PG&E's) gas compressor station, numerous wind farms, four 500 kV transmission lines four 230 kV lines and several lower-voltage lines.

To assess the likelihood of soil contamination from past agricultural operations at the site, the applicant commissioned a Phase I Environmental Site Assessment (ESA) survey to identify any locations of specific chemical contamination. The survey was conducted according to procedures specified by the American Society for Testing and Materials (EAEC 2001a, page 8.13-1 and Appendix 8.13). This survey revealed the following main areas of potential contamination as detailed in the information from the applicant:

- The residence and barn at the southwest corner that were used for farm chemical storage;
- A former chicken coop that was used for pesticide storage, handling and preparation;
- Former equipment storage and maintenance areas and related aboveground waste oil storage areas that could have been contaminated by chemical lubricants, and petroleum products; and
- The site of an underground petroleum storage tank removed approximately 10 years ago.

The Department of Toxic Substances Control (DTSC) requested in an October 16, 2001 memorandum to Commission staff that the applicant's intended Site Mitigation Implementation Plan (SMIP) be required to include specific procedures for (a) characterizing any such contamination with respect to constituents and concentrations, and (b) removing the constituent chemicals before site preparation and facility construction. Staff recommends a specific condition of certification (**WASTE-1**) to address this request.

IMPACTS

PROJECT SPECIFIC IMPACTS

Construction related

As noted by the applicant (EAEC 2001a, pages 8.13-2 through 8.13-6), site preparation and construction for the proposed project and related facilities will generate both hazardous and non-hazardous wastes. The non-hazardous component of the construction-related wastes will include waste paper, wood, glass, scrap metal, and plastics, from packing materials, waste lumber, excess concrete, insulation materials, and non-hazardous chemical containers. The applicant estimates that up to 195 tons of such non-hazardous wastes will be generated (EAEC 2001, page 8.13-3). These wastes will be segregated, where practical, for recycling. Those that cannot be recycled

will be placed in covered containers and removed on a regular basis by a certified waste handling contractor for disposal at a Class III facility.
The relatively small quantities of hazardous materials to be generated during this construction phase will mainly consist of used oil, waste paint, spent solvents, welding materials, batteries, and cleaning chemicals. These wastes will be recycled or disposed of at licensed hazardous waste treatment or disposal facilities (EAEC 2001a, page 8.13-4). As noted by the applicant (EAEC 2001a, page 2001a, page 8.13-4), the construction contractor will be considered the generator of the hazardous waste produced during construction and will be responsible for compliance with applicable federal and state regulations regarding licensing, personnel training, accumulation limits, reporting requirements, and record keeping.

Operations related

Under normal operating conditions, the facility will generate both hazardous and non-hazardous wastes as noted by the applicant (EAEC 2001a pages 8.13 through 8.13-6). The non-hazardous component will include routine maintenance-related trash, office wastes, empty containers, broken or used parts, and used packaging materials and air filters. Some of the wastes will be recycled to minimize the quantity to be disposed of in a landfill. The non-recyclables will be disposed of at a non-hazardous waste disposal facility. The volume of non-hazardous wastes from the proposed and similar gas-fired facilities is typically small and readily accommodated within area disposal facilities. For the proposed facility for example, the estimated 70 cubic yards to be generated per year, would easily be accommodated within the area's listed Class III landfills or waste disposal facilities that could be utilized (EAEC 2001, page 8.13-7).

The operations-related hazardous wastes will include spent air pollution control catalysts, used oil and air filters, used cleaning solvents, cooling tower sludge, and oily rags. As noted by the applicant (EAEC 2001a, page 8.13-4), some of these wastes will be recycled. These will include the spent air pollution control catalysts, used oil from equipment maintenance, and oil-contaminated materials such as rags or other cleanup materials. The non-recyclables will be disposed of in a Class I disposal facility.

POTENTIAL IMPACTS ON EXISTING WASTE DISPOSAL FACILITIES

The applicant has provided a listing of the four area non-hazardous waste disposal facilities available for use (EAEC 2001a, page 8.13-7). This listing includes information on location, total permitted capacity, remaining capacity, and anticipated year of closure. This information shows that the volume of the waste from project construction and operation would be insignificant relative to available disposal capacity.

As discussed by the applicant (EAEC 2001a, pages 8.13-8 and 8.13-9), there are three major Class I landfills in California available for the disposal of hazardous wastes from the proposed and similar projects. These are Safety-Kleen's Buttonwillow Landfill in Kern County, Safety Kleen's Westmoreland Landfill in Imperial County, and Chemical Waste Management Landfill in Kings County. There is a total of more than twenty million cubic yards of disposal space within these landfills, reflecting a total operational life of up to 90 years. The operational lives of these facilities are expected to be lengthened by two factors: (a) the success of the state's waste reduction program in reducing the volume of wastes to be disposed of and (b) the phenomenon of out-of-

state disposal of wastes deemed hazardous under California law, but not under federal law. Given this information, staff concludes that adequate disposal space would be available to serve the project throughout its operational life.

CUMULATIVE IMPACTS

While the hazardous and non-hazardous wastes from construction and operation of the proposed EAEC will add to the total wastes generated in Alameda County and in California, staff does not consider the volume involved as significantly affecting the remaining operational lives of the landfills to be used. No modifications are recommended with respect to the applicant's proposed handling and disposal plans.

FACILITY CLOSURE

During any type of facility closure (whether temporary or permanent), the primary waste management-related issue of concern would be the potential for significant health impacts from worker or public exposure to hazardous materials on site. In the case of unexpected temporary closure, requirements under existing LORS (such as limiting hazardous waste accumulation time to 90 days and requiring proper containment) would be adequate to minimize exposures. By contrast, specific contingency plans are required with respect to temporary closures of more than 90-days to ensure removal of hazardous wastes and draining of all chemicals from storage tanks and other equipment.

A specific on-site contingency plan is also necessary in case of unexpected permanent closure, to ensure (a) the removal of hazardous materials and hazardous wastes, (b) the draining of all chemicals from storage tanks and other equipment, and (c) the safe shutdown of all equipment. For all such closures, a specific facility closure plan is required from the applicant at least twelve months before the start of closure-related activities

COMPLIANCE WITH APPLICABLE LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

Staff concludes from the applicant's submittal that their plan for managing the wastes from the project's construction, operation, and closure would be in accordance with existing LORS designed to minimize the potential for human health and environmental effects. The applicant will dispose of all project-related hazardous and non-hazardous only at facilities they have identified as appropriate for such purposes. An EPA identification number will also be obtained because of the applicant's potential status as a hazardous waste generator. Any on-site storage, handling or disposal of hazardous materials will be as required under California Code of Regulations, Title 22, Section 67100 et seq.

MITIGATION

The adequacy of the applicant's waste management plan is facilitated by their planned implementation of specific mitigation measures (EAEC 2001a, pages 8.13-9 through 8.13-12). The most significant of these measures include the following:

- Storing hazardous wastes on site for less than 90 days and ensuring that such wastes are stored only in hazardous waste storage areas surrounded by containment structures;
- Ensuring that hazardous wastes are handled and disposed of only by licensed hazardous waste handlers; and
- Training facility workers with respect to waste handling, containment and minimization procedures.

Staff recommends specific conditions of certification to ensure implementation of these and the other facilitative measures.

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

Staff has determined that the applicant's waste management plan for the proposed EAEC would allow for compliance with LORS designed to minimize the potential for human health and environmental effects.

RECOMMENDATIONS

To ensure implementation of all necessary mitigation measures, staff recommends adoption of the conditions of certification listed below.

CONDITIONS OF CERTIFICATION

WASTE 1. The project owner shall submit to the Energy Commission's Compliance Project Manager (CPM) a Site Mitigation Implementation Plan (SMIP) detailing the procedures for assessing the need for specific contaminant mitigation in the areas noted by the applicant as possible locations of specific contamination from past on-site agricultural operations. This SMIP shall specifically include the measures necessary to (a) identify the contaminants involved and (b) complete such mitigation at least 30 days before the start of ground disturbance.

Verification: The required Site Mitigation Implementation Plan shall be prepared and implemented to allow the applicant to inform the CPM of the absence of specific on-site contaminants, at least 30 days before the start of ground disturbance.

WASTE-2 The project owner shall obtain a hazardous waste generator identification number from USEPA prior to generating any hazardous waste.

Verification: The project owner shall keep its copy of the identification number on file at the project site and notify the CPM through its initial monthly compliance report.

WASTE-3 Upon becoming aware of any impending waste management-related enforcement action, the project owner shall notify the CPM of any such action whether it is to be taken against the project owner, the waste transporter under contract, or the disposal or treatment facility to be used.

Verification: The project owner shall notify the CPM in writing within 10 days of becoming aware of an impending enforcement action.

WASTE-4 Prior to the start of both site mobilization and commercial operation, the project owner shall prepare and submit to the CPM, for review and approval, a waste management plan with respect to all wastes generated during construction and operation of the facility. The plan shall include the following at a minimum:

- A description of all expected types of wastes including the estimates of the amounts expected;
- The applicable waste management methods including the treatment methods, treatment facilities, classification procedures, transportation methods, disposal requirements, facility location, and recycling and waste minimization/reduction measures.

Verification: No less than 60 days prior to the start of site mobilization, the project owner shall submit the construction waste management plan to the CPM for review. The operations-related waste management plan shall be submitted no less than 60 days prior to the start of commercial operation. The project owner shall submit any required revisions within 30 days of notification by the CPM (or on a mutually agreed upon date). In the Annual Compliance Reports, the project owner shall document the actual waste management methods used in the course of the year.

WASTE-*5* The project owner shall have a Registered Professional Engineer or Geologist, with experience in remedial investigation and feasibility studies, available for consultation during ground disturbance, grading or construction. The Registered Professional Engineer or Geologist shall be given full authority to oversee any earth moving activities that have the potential to disturb contaminated soil.

Verification: At least 30 days prior to the start of ground disturbance, the project owner shall submit the qualifications and experience of the Registered Professional Engineer or Geologist to the CPM for approval.

WASTE-6 If potentially contaminated soil is unearthed during ground disturbance at either the proposed site or linear facilities as evidenced by discoloration, odor, detection by handheld instruments, or other signs, the Registered Professional Engineer or Geologist shall inspect the site, determine the need for sampling to confirm the nature and extent of contamination, and file a written report to the project owner and CPM stating the recommended course of action. Depending on the nature and extent of contamination, the Registered Professional Engineer or Geologist shall have the authority to temporarily suspend ground disturbance at that location for the protection of workers or the public. If, in the opinion of the

Registered Professional Engineer or Geologist, significant remediation may be required, the project owner shall (within 24 hours) contact representatives of the San Francisco Regional Water Quality Control Board, the Alameda County Department of Environmental Health, the Berkeley Regional Office of the California Department of Toxic Substances Control, and CPM for guidance and possible oversight.

Verification: The project owner shall submit any reports filed by the Registered Professional Engineer or Geologist to the CPM within 5 days of their receipt.

REFERENCES

California Environmental Protection Agency and Regional Water Quality Control Boards, 1999. Wastes Allowed for Discharge at Disposal Facilities. April 24.

EAEC (East Altamont Energy Center) 2001a. Application for Certification, Volume 1 & Appendices, East Altamont Energy Center (01-AFC-4), Dated March 20, 2001 and docketed March 20, 2001 at the California Energy Commission.

WORKER SAFETY AND FIRE PROTECTION

Alvin J. Greenberg, Ph.D. and Rick Tyler

INTRODUCTION

Worker safety and fire protection is legislated by laws, ordinances, regulations, and standards (LORS), and enforced through regulations codified at the Federal, State, and local levels. Worker safety is of utmost priority at the project location and is documented through worker safety practices and training. Industrial workers at the facility operate process equipment and handle hazardous materials daily and may face hazards that can result in accidents and serious injury. Protection measures are employed to either eliminate these hazards or minimize the risk through special training, protective equipment or procedural controls.

The purpose of this analysis is to assess whether the worker safety and fire protection measures proposed by Calpine, D.B.A East Altamont Energy Center, LLC (applicant) for the East Altamont Energy Center (EAEC) are adequate measures to:

- comply with applicable safety LORS;
- protect the workers during construction and operation of the facility;
- protect against fire; and
- provide adequate emergency response procedures.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

FEDERAL

In December 1970 Congress enacted Public Law 91-596, the Federal Occupational Safety and Health Act of 1970 (OSA Act). This Act mandates safety requirements in the workplace and is found in Title 29 of the United States Code, § section 651 (29 U.S.C. §§ 651 through 678). Implementing regulations are codified at Title 29 of the Code of Federal Regulations, under General Industry Standards §§ 1910.1 - 1910.1500 and clearly 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. Most of the general industry safety and health standards now in force under this OSH Act represent a compilation of materials from existing federal standards and national consensus standards. These include standards from the voluntary membership organizations of the American National Standards Institute (ANSI) and the National Fire Protection Association (NFPA) which publishes the National Fire Codes.

The purpose of the Occupational Safety and Health Act is to “assure so far as possible every working man and woman in the nation safe and healthful working conditions and to preserve our human resources,” (29 U.S.C. § 651). The Federal Department of Labor promulgates and enforces safety and health standards that are applicable to all businesses affecting interstate commerce. The Department of Labor established the

Occupational Safety and Health Administration (OSHA) in 1971 to discharge the responsibilities assigned by the OSH Act.

Applicable Federal requirements include:

- Occupational Safety and Health Act of 1970 29 U.S.C. § 651 et seq.;
- Occupational Safety and Health Administration Safety and Health Regulations 29 C.F.R. §1910.1 - 1910.1500;
- 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 C.F.R. §§ 1910.1 – 1910.1500 and §§ 1952.170 – 1952.175.

STATE

California passed the Occupational Safety and Health Act of 1973 ("Cal/OSHA") as codified in the California Labor Code § 6300 et seq. Regulations promulgated as a result of the Act are codified at Title 8 of the California Code of Regulations, beginning with sections 337-560 and continuing with sections1514 through 8568. The California Labor Code requires that the Cal/OSHA Standards Board adopt standards at least as effective as the federal standards (Labor Code § 142.3(a)). Thus all Cal/OSHA health and safety standards meet or exceed the Federal requirements. California obtained federal approval of its State health and safety regulations, in lieu of the federal requirements which are codified at 29 CFR §1910.1 - 1910.1500. The Federal Secretary of Labor, however, continually oversees California's program and will enforce any federal standard for which the State has not adopted a Cal/OSHA counterpart.

Employers are responsible for informing their employees about workplace hazards, potential exposure and the work environment (Labor Code § 6408). Cal/OSHA's principal tool in ensuring that workers and the public are informed is the Hazard Communication standard first adopted in 1981 Cal. Code Regs., tit. 8, §5194. This regulation was promulgated in response to California's Hazardous Substances Information and Training Act of 1980. It was later revised to mirror the Federal Hazard Communication Standard (29 C.F.R. §1910.1200) which established on the federal level an employee's "right to know" about chemical hazards in the workplace, but added the provision of applicability to public sector employers. A major component of this regulation is the required provision of Material Safety Data Sheets (MSDSs) to workers. MSDSs provide information on the identity, toxicity, and precautions to take when using or handling hazardous materials in the workplace.

Finally, California Code of Regulations, title 8 section 3203 requires that employers establish and maintain a written Injury and Illness Prevent Program to identify workplace hazards and communicate them to its employees through a formal employee-training program.

Applicable State requirements include:

- Cal. Code Regs., tit. 8, §339 - List of hazardous chemicals relating to the Hazardous Substance Information and Training Act;
- Cal. Code Regs., tit. 8, §337, et seq. Cal/OSHA regulations;

- Cal. Code Regs., tit. 24, § 3 et seq. - incorporates the current addition of the Uniform Building Code;
- Health and Safety Code § 25500 et seq. - Risk Management Plan requirements for threshold quantity of listed acutely hazardous materials at the facility;
- Health and Safety Code §§ 25500 - 25541 - Hazardous Material Business Plan detailing emergency response plans for hazardous materials emergency at the facility.

LOCAL

The California Building Standards Code published at Title 24 of the California Code of Regulations section 3 et seq is comprised of eleven parts containing the building design and construction requirements relating to fire and life safety and structural safety. The Building Standards Code includes the electrical, mechanical, energy, and fire codes applicable to the project. Local planning/building & safety departments enforce the California Uniform Building Code.

National Fire Protection Association (NFPA) standards are published in the California Fire Code. The fire code contains general provisions for fire safety, including but not restricted to: 1) required road and building access; 2) water supplies; 3) installation of fire protection and life safety systems; 4) fire-resistive construction; 5) general fire safety precautions; 6) storage of combustible materials; 7) exits and emergency escapes; and 8) fire alarm systems. The California Fire Code reflects the body of regulations published at Cal. Code Regs., 24 (Health and Safety Code §18901 et seq.) pertaining to the California Fire Code.

Similarly, the Uniform Fire Code (UFC) Standards, a companion publication to the California Fire Code, contains standards of the American Society for Testing and Materials and the NFPA. It is the United State's premier model fire code. It is updated annually as a supplement and published every third year by the International Fire Code Institute to include all approved code changes in a new edition. The latest revision of the Uniform Fire Code adopted into the Alameda County Fire Code is the 1997 version (Chapter 6.04 of Title 6 of the Alameda County General Ordinance Code). The Alameda County Fire Department administers the UFC.

Applicable local (or locally enforced) requirements include:

- 1998 Edition of California Fire Code and all applicable NFPA standards (Title 24, California Code of Regulations, sections 901-907);
- California Building Code Title 24, California Code of Regulations, section 3 et seq.
- Uniform Fire Code, 1997

SETTING

The proposed project is located in unincorporated Alameda County, about 1 mile west of the San Joaquin County line and one mile southeast of the Contra Costa County line.

The EAEC will be located on about 40 acres of the 174-acre parcel of land under the Applicant's control.

Fire support services to the site will be under the jurisdiction of the Alameda County Fire Department, with mutual aid provided by the Tracy Fire Department (San Joaquin County). The closest Alameda County Fire Station to the site is Station No. 8, located at 1617 College Avenue in Livermore. Staff contacted the Alameda County Fire department and determined that the response time to the project site is estimated to be 15 minutes (ACFD 2001a). Fire Station No. 8 has 2 engines and 3 squads and services a response area of 280 square miles of open rangeland and freeway (ACFD 2001b). In the event of a fire emergency at the EAEC, Alameda County Central Dispatch would send Station 8 and contact the Tracy Fire Department to respond as well, under the automatic aid agreement between the two counties. The Tracy Fire Department would respond with an estimated response time of about 6 minutes (ACFD 2001a).

Alameda County Fire Department Station 4, located at 20336 San Miguel Avenue in Castro Valley, is the hazmat first responder. Response time for Station 4 is estimated to be 35 minutes. Firefighters from Station 8 and the Tracy Fire Department would secure the site until they arrived. Station 4 has 24-hour hazmat capabilities, a hazmat engine and at least six personnel on duty (ACFD 2001a).

In response to the construction of the EAEC, the County is planning to relocate Station 8, which is currently located in downtown Livermore, closer to the EAEC site, at a location near Interstate 580 and Greenhill Road. Estimated response time from that location would be 10 minutes to the EAEC. According to Fire Marshall Ferdinand, the relocation of Station 8 would enhance the firefighting capabilities of the Alameda County Fire Department in the rural area where the EAEC is proposed. Adverse effects on the staff of the ACFD are not expected due to this move (ACFD 2001a,c).

IMPACTS

PROJECT SPECIFIC IMPACTS

Industrial environments are potentially dangerous, during both construction and operation of facilities. Workers at the proposed project will be exposed to loud noises, moving equipment, trenches, and confined space entry and egress problems. The workers may experience falls, trips, burns, lacerations, and numerous other injuries. They have the potential to be exposed to falling equipment or structures, chemical spills, hazardous waste, fires, explosions, and electrical sparks and electrocution. It is important for the EAEC to have well-defined policies and procedures, training, and hazard recognition and control at their facility to minimize such hazards and protect workers. If the facility complies with all LORS, workers will be adequately protected from health and safety hazards.

During construction and operation of the proposed EAEC there is the potential for both small fires and major structural fires. Electrical sparks, combustion of fuel oil, natural gas or flammable liquids, explosions, and over-heated equipment, may cause small fires. Major structural fires may develop from uncontrolled fires or be caused by large

explosions of natural gas or other flammable gasses or liquids. Compliance with all LORS will be adequate to assure protection from all fire hazards.

CUMULATIVE IMPACTS

Staff reviewed the potential for the construction and operation of the EAEC, combined with existing industrial facilities, to result in impacts on the fire and emergency service capabilities of the Alameda County Fire Department and found that cumulative impacts were insignificant. No request for additional equipment, staffing, or funding has been made by local authorities. Other power plant projects proposed for this same general area may change this opinion in the near future and should be resolved by the time the FSA is issued.

APPLICANT'S PROPOSED MITIGATION

A Safety and Health Program will be prepared by the applicant to minimize worker hazards during construction and operation. Staff uses the phrase "Safety and Health Program" to refer to the measures that will be taken to ensure compliance with the applicable LORS during the construction and operational phases of the project.

CONSTRUCTION SAFETY AND HEALTH PROGRAM

The EAEC Workers will be exposed to hazards typical of construction and operation of a gas-fired combined cycle facility.
Construction Safety Orders are published at California Code of Regulations, title 8, section 1502 et seq. These requirements are promulgated by Cal/OSHA and are applicable to the construction phase of the project. The Construction Safety and Health Program will include the following:

- Construction Injury and Illness Prevention Program (Cal Code Regs., tit. 8, § 1509);
- Construction Fire Protection and Prevention Plan (Cal Code Regs., tit. 8, § 1920); and
- Personal Protective Equipment Program (Cal Code Regs., tit. 8, §§ 1514 - 1522).

Additional programs under General Industry Safety Orders (Cal Code Regs., tit. 8, §§ 3200 - 6184), Electrical Safety Orders (Cal Code Regs., tit. 8, §§2299 - 2974) and Unfired Pressure Vessel Safety Orders (Cal Code Regs., tit. 8, §§ 450 - 544) will include:

- Electrical Safety Program;
- Unfired Pressure Vessel Safety Orders;
- Equipment Safety Program;
- Forklift Operation Program;
- Excavation/Trenching Program;
- Fall Prevention Program;
- Scaffolding/Ladder Safety Program;

- Articulating Boom Platforms Program;
- Crane and Material Handling Program;
- Housekeeping and Material Handling and Storage Program;
- Hot Work Safety Program;
- Respiratory Protection Program;
- Employee Exposure Monitoring Program;
- Confined Space Entry Program;
- Hand and Portable Power Tool Safety Program;
- Hearing Conservation Program;
- Back Injury Prevention Program;
- Hazard Communication Program;
- Air Monitoring Program;
- Heat and Cold Stress Monitoring and Control Program; and
- Pressure Vessel and Pipeline Safety Program.

The AFC includes adequate outlines of each of the above programs. Prior to construction of the EAEC, detailed programs and plans will be provided pursuant to condition of certification **WORKER SAFETY-1**.

OPERATIONS AND MAINTENANCE SAFETY AND HEALTH PROGRAM

Upon completion of construction and prior to start of operation at the EAEC, the Operations and Maintenance Safety and Health Program will be prepared. This operational safety program will include the following programs and plans:

- Injury and Illness Prevention Program (Cal Code Regs., tit. 8,§ 3203);
- Emergency Action Plan (Cal Code Regs., tit. 8,§ 3220);
- Hazardous Materials Management Program;
- Operations and Maintenance Safety Program;
- Fire Protection and Prevention Program (Cal Code Regs., tit. 8, § 3221); and
- Personal Protective Equipment Program (Cal Code Regs., tit. 8, §§ 3401-3411).

In addition, the requirements under General Industry Safety Orders (Cal Code Regs., tit. 8, §§ 3200 - 6184), Electrical Safety Orders (Cal Code Regs., tit. 8, §§2299 - 2974) and Unfired Pressure Vessel Safety Orders (Cal Code Regs., tit. 8, §§ 450 - 544) will be applicable to the project. Written safety programs, which the applicant will develop, for the EAEC will ensure compliance with the above-mentioned requirements.

The AFC includes adequate outlines of the Construction and Operation Health and Safety Programs as well as the Emergency Action Program/Plan, the Construction and Operation Injury and Illness Prevention Programs and the Fire Protection and

Prevention Programs (EAEC 2001a, AFC Sections 8.7.3.1 and 8.7.3.2). Prior to operation of the East Altamont Energy Center project, all detailed programs and plans will be provided pursuant to condition of certification **WORKER SAFETY-2**.

SAFETY AND HEALTH PROGRAM ELEMENTS

The Applicant provided the proposed outlines for both a Construction Safety and Health Program and an Operation 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 Applicant will submit an expanded Construction and Operations Illness and Injury Prevention Program to Cal/OSHA for review and comment 30 days prior to both construction and operation of the project.

The IIPP will include the following components as presented in the AFC:

- Identity of person(s) with authority and responsibility for implementing the program;
- System ensuring employees comply with safe and healthy work practices;
- System facilitating employer-employee communications;
- Procedures identifying and evaluating workplace hazards, including inspections to identify hazards and unsafe conditions;
- Methods for correcting unhealthy/unsafe conditions in a timely manner;
- Methods of documenting inspections and training and for maintaining records; and
- A training program for:
- introducing the program;
- new, transferred, or promoted employees;
- new processes and equipment;
- supervisors; and
- contractors.

Emergency Action Plan

California regulations require an Emergency Action Plan (Cal Code Regs., tit. 8, § 3220). The AFC contains a satisfactory outline for an emergency action plan (EAEC 2001a, AFC Sections 8.7.3.1 and 8.7.3.2).

The outline lists the following features:

- Purpose and Scope of Emergency Action Plan;
- Personnel Responsibilities during Emergencies;
- Specific Response Procedures;
- Evacuation Plan;

- Emergency Equipment Locations;
- Fire Extinguisher Locations;
- Site Security;
- Accident Reporting and Investigation;
- Lockout/Tagout;
- Hazard Communication;
- Spill Containment and Reporting;
- First Aid and Medical Response;
- Respiratory Protection;
- Personal Protective Equipment;
- Sanitation; and
- Work Site Inspections.

Fire Prevention Plan

California Code of Regulations requires an Operations Fire Prevention Plan (Cal Code Regs., tit. 8, § 3221). The AFC describes a proposed fire prevention plan which is acceptable to staff. The plan will include the following topics:

- Responsibilities of employees and management;
- Procedures for fire control;
- Fixed and Portable fire-fighting equipment;
- Housekeeping;
- Employee alarm/communication practices;
- Servicing and refueling areas;
- Training; and
- Flammable and combustible liquid storage.

Staff proposes that the Applicant submit a final Fire Protection and Prevention Plan to the California Energy Commission Compliance Project Manager (CPM) and the Alameda County Fire Department for review and approval to satisfy proposed condition of certification **WORKER SAFETY-1** and **2**.

Personal Protective Equipment Program

California regulations require Personal Protective Equipment (PPE) and first aid supplies whenever hazards are encountered which, due to process, environment, chemicals or mechanical irritants can cause injury or impair bodily function as a result of absorption, inhalation or physical contact (Cal Code Regs., tit. 8, § 3380-3400). The East Altamont Energy Center project operational environment will require the availability of PPE.

Information provided in the AFC indicates that all employees required to use PPE will be checked for proper fit and to see if they are medically capable of wearing the equipment. All safety equipment will meet NIOSH or ANSI standards and will carry markings, numbers, or certificates of approval. Respirators will meet NIOSH and California Department of Health and Human Services Standards. Each employee will be provided with the following information pertaining to the protective clothing and equipment:

- Proper use, maintenance, and storage;
- When the protective clothing and equipment are to be used;
- Benefits and limitations; and
- When and how the protective clothing and equipment are to be replaced.

The PPE Program ensures that employers comply with the applicable requirements for PPE and provide employees with the information and training necessary to implement the program.

Operations and Maintenance Written Safety Program

In addition to the specific plans listed above, there are additional LORS applicable to the project, which are called "safe work practices". Both the Construction and the Operations Safety Programs will address safe work practices under a variety of programs. The components of these programs include the following:

- Fall Protection Program;
- Hot Work Safety Program;
- Confined Space Entry;
- Hearing Conservation Program;
- Hazard Communication Program;
- Process Safety Management (PSM) Program; and
- Contractor Safety Program.

Operations and Maintenance Safety Training Programs

Employees will be trained in the safe work practices described in the above-referenced safety programs.

FIRE PROTECTION

Staff reviewed the information regarding available fire protection services and equipment (EAEC 2001a, AFC Sections 2.3.2.1 Fire Protection Systems and 8.7 Worker Health and Safety) to determine if the project would adequately protect workers and if it would affect the fire protection services in the area. Staff agrees with the Applicant that the project should rely on both onsite fire protection systems and local fire protection services. The onsite fire protection system provides the first line of defense for small fires. In response to a staff data request (EAEC 2001v, page 22), project

operations staff will be thoroughly trained to respond to small fire, activate fire suppression systems, or notify the off-site fire department. In the event of a major fire, fire support services including trained firefighters and equipment for a sustained response would be required by the Alameda County Fire Department.

The Applicant intends to meet the minimum fire protection and suppression requirements as mandated by the Alameda County Fire Code, NFPA Standards, and the UFC. Elements include both fixed and portable fire extinguishing systems. Raw water for use as fire water will be supplied by the Byron Bethany Irrigation District (BBID). A dedicated fire water storage supply of a minimum of 240,000 gallons will be stored in the raw water storage tanks. An on-site electric jockey pump and electric motor driven main fire pump will be provided to increase the water pressure in the plant fire mains to the level required to serve all fire fighting systems. Additionally, a diesel engine-driven fire pump will be provided to pressurize the fire loop if the power supply to the main fire pump fails.

A fire protection system will be provided for the combustion turbine, generator and accessory equipment. Fire detection sensors will also be installed.

A deluge spray system will provide fire suppression for the generator transformers and auxiliary power transformers. Fire hydrants and hose stations will be used to supplement the plant fire protection system.

In addition to the fixed fire protection system, fire extinguishers will be located throughout the plant Administrative/Maintenance Building, water treatment facility, and other structures as required by the local fire department.

The applicant will be required to provide the final Fire Protection and Prevention Program to staff and to the Alameda County Fire Department, prior to construction and operation of the project, to confirm the adequacy of the proposed fire protection measures.

FACILITY CLOSURE

The project owner/operator is responsible for maintaining an operational fire protection system during closure activities. The project must also stay in compliance with all applicable health and safety LORS during that time. A facility closure plan will be developed prior to closure to incorporate these requirements.

RESPONSE TO PUBLIC AND AGENCY COMMENTS

AGENCY COMMENTS

Alameda County Fire Department

COMMENT: *The Alameda County Fire Department wanted to ensure that certain portions of the Alameda County Fire Code, NFPA Standards, and the UFC were followed.*

RESPONSE: The Applicant must comply with all LORS. Proposed Condition of Certification WORKER SAFETY-1 and 2 require that the project owner submit certain fire prevention plans to the Alameda County Fire Department for review and comment prior to the commencement of construction or operations.

Public Comments

Roy Berg
Mr. Berg notes that a truly effective accident prevention program can only be maintained by constant on-site management vigil and employee participation.

RESPONSE: Staff agrees with Mr. Berg and believes that the CPM along with Cal/OSHA will ensure such vigilance and participation.

CONCLUSION AND RECOMMENDATIONS

If the Applicant for the proposed East Altamont Energy Center project provides a Project Construction Injury and Illness Prevention Program and a Project Operations Safety and Health Program as required by conditions of certification **WORKER SAFETY-1** and **2**, staff believes that the project will incorporate sufficient measures to ensure adequate levels of industrial safety, and comply with applicable LORS. Staff also concludes that the proposed plant will not have significant impacts on local fire protection services. The proposed facility is located within an area that is currently served by the local fire department. The fire risks of the proposed facility do not pose significant added demands on local fire protection services.

If the Commission certifies the project, staff recommends that the Commission adopt the following proposed conditions of certification. The proposed conditions of certification provide assurance that the Construction Injury and Illness Prevention Program and the Operations Safety and Health Program proposed by the applicant will be reviewed by the appropriate agencies before implementation. The conditions also require verification that the proposed plans adequately assure worker safety and fire protection and comply with applicable LORS.

PROPOSED CONDITIONS OF CERTIFICATION

WORKER SAFETY-1 The project owner shall submit to the CPM a copy of the Project Construction Injury and Illness Prevention Program, containing the following:

- A Construction Safety Program;
- A Construction Personal Protective Equipment Program;
- A Construction Exposure Monitoring Program;
- A Construction Emergency Action Plan; and
- A Construction Fire Protection and Prevention Plan.

The Safety Program, the Personal Protective Equipment Program, and the Exposure Monitoring Program shall be submitted to the CPM for review and comment concerning compliance of the program with all applicable Safety Orders. The Construction Fire Protection and Prevention Plan and Emergency Action Plan shall be submitted to the Alameda County Fire Department for review and comment prior to submittal to the CPM.

Verification: At least 30 days prior to site mobilization, the project owner shall submit to the CPM for review and approval a copy of the Project Construction Injury and Illness Prevention Program. The project owner shall provide a letter from the Alameda County Fire Department stating that they have reviewed and commented on the Construction Fire Protection and Prevention Plan 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;
- Operations and Maintenance Safety Program;
- Fire Protection and Prevention Program (Cal Code Regs., tit. 8,§ 3221); and;
- Personal Protective Equipment Program (Cal Code Regs., tit. 8,§§ 3401-3411).

The Operation Injury and Illness Prevention Plan, Emergency Action Plan, and Personal Protective Equipment Program shall be submitted by the project owner to the Cal/OSHA Consultation Service, for review and comment concerning compliance of the program with all applicable Safety Orders. The Operation Fire Protection Plan and the Emergency Action Plan shall also be submitted by the project owner to the City of Alameda County Fire Department for review and acceptance.

Verification: At least 30 days prior to the start of operation, the project owner shall submit to the CPM a copy of the final version of the Project Operations and Maintenance Safety & Health Program. It shall incorporate Cal/OSHA Consultation Service's comments, stating that they have reviewed and accepted the specified elements of the proposed Operations and Maintenance Safety and Health Plan.

REFERENCES

Alameda County Fire Department (ACFD). 2001a. Personal communication with Fire Marshall Jim Ferdinand. July 30, 2001.

Alameda County Fire Department (ACFD). 2001b. ACFD website at http://www.co.alameda.ca.us/fire/geninfo.shtml#Locations

Alameda County Fire Department (ACFD). 2001c. Personal communication with Fire Marshall Jim Ferdinand. November 2001.

1998 California Fire Code. Published by the International Fire Code Institute comprised of the International Conference of Building Officials, the Western Fire Chiefs Association, and the California Building Standards Commission. Whittier, Ca.

EAEC (East Altamont Energy Center) 2001a. Application for Certification, Volume 1 & Appendices, East Altamont Energy Center (01-AFC-4). Dated March 20, 2001 and docketed March 29, 2001.

EAEC (East Altamont Energy Center) 2001v. Data Response Set 3. Dated and docketed October 9, 2001.

1997 Uniform Fire Code, Vol. 1. Published by the International Fire Code Institute comprised of the International Conference of Building Officials and the Western Fire Chiefs Association, Whittier, Ca.

ENGINEERING ASSESSMENT

FACILITY DESIGN

Brian Payne

INTRODUCTION

Facility Design encompasses the civil, structural, mechanical and electrical engineering design of the project. The purpose of the Facility Design analysis is to:

- Verify that the laws, ordinances, regulations and standards (LORS) applicable to the engineering design and construction of the project have been identified;
- Verify that the project and ancillary facilities have been described in sufficient detail, including proposed design criteria and analysis methods, to provide reasonable assurance that the project can be designed and constructed in accordance with all applicable engineering LORS, and in a manner that assures public health and safety;
- Determine whether special design features should be considered during final design to deal with conditions unique to the site which could influence public health and safety; and
- Describe the design review and construction inspection process and establish Conditions of Certification that will be used to monitor and ensure compliance with the intent of the engineering LORS and any special design requirements.

FINDINGS REQUIRED

The Warren Alquist Act requires the commission to "prepare a written decision. …which includes…(a) Specific provisions relating to the manner in which the proposed facility is to be designed, sited, and operated in order to protect environmental quality and assure public health and safety [and] (d)(1) Findings regarding the conformity of the proposed site and related facilities…with public safety standards…and with other relevant local, regional, state and federal standards, ordinances, or laws…" (Pub. Resources Code, §25523).

SUBJECTS DISCUSSED

Subjects discussed in this analysis include:

- Identification of the engineering LORS applicable to facility design;
- Evaluation of the applicant's proposed design criteria, including the identification of those criteria that are essential to ensuring public health and safety;
- Proposed modifications and additions to the Application for Certification (AFC) that are necessary to comply with applicable engineering LORS; and
- Conditions of Certification proposed by staff to ensure that the project will be designed and constructed to assure public health and safety and comply with all applicable engineering LORS.

SETTING

The applicant, East Altamont Energy Center, L.L.C. (EAEC), a wholly owned subsidiary of Calpine Corporation, proposes to construct and operate a new 1,100 megawatt (MW) nominal, natural gas fired, combined cycle power plant. This plant is proposed for construction in the northeastern edge of Alameda County, approximately eight miles northwest of the city of Tracy, twelve miles east of the city of Livermore, and five miles south of the city of Byron. The site is located approximately one-quarter mile east of Western's Tracy substation and one and one-half miles east of Pacific Gas and Electric Company's (PG&E's) natural gas transmission pipeline. This facility is proposed to include three natural gas fired combustion turbines with electrical generators, three multistage heat recovery steam generators, and one steam turbine generator. A new switchyard and one-half mile interconnecting transmission lines will also be constructed. Other linear facilities will include a new 1.4 mile, 20" nominal diameter, natural gas interconnecting pipeline; a 4.6 mile recycled water supply line; and a 2.1 mile, 24" nominal diameter, water supply pipeline (EAEC 2001a). For more information on the site and related project description, please see **Project Description**.

The site lies in seismic zone 4, the zone of greatest seismic shaking in the United States. Additional engineering design details are contained in the Application for Certification (AFC) Sections 2.3, 8.15, and 10, and the AFC Appendices 10A through 10F (EAEC 2001a).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

The applicable LORS for each engineering discipline (civil, structural, mechanical, electrical, and controls) are described in AFC Section 10.4, the following AFC Appendices (EAEC 2001a), and Data Adequacy Response Set 1, Section 2.5 (EAEC 2001e).

- Appendix 10A – Civil Engineering Design Criteria
- Appendix 10B – Structural Engineering Design Criteria
- Appendix 10C – Mechanical Engineering Design Criteria
- Appendix 10D – Electrical Engineering Design Criteria
- Appendix 10E – Control Systems Engineering Design Criteria
- Appendix 10F – Chemical Engineering Design Criteria

Some of these LORS include: California Building Code (CBC), American National Standards Institute (ANSI), American Society of Mechanical Engineers (ASME), American Society for Testing and Materials (ASTM), and the American Boiler Manufacturers Association (ABMA).

ANALYSIS

The basis of this analysis is the applicant's proposed analysis and construction methods and the list of engineering LORS and design criteria set forth in the AFC.

SITE PREPARATION AND DEVELOPMENT

Staff has evaluated the proposed design criteria for grading, flood protection, erosion control, site drainage, and site access. Staff has assessed the criteria for designing and constructing linear support facilities such as a natural gas pipeline, fresh water supply pipeline, a recycled water supply line, and an electric transmission line. The applicant proposes to use accepted industry standards (see EAEC 2001a, Appendices 10A through 10F for a representative list of applicable industry standards), design practices, and construction methods in preparing and developing the site. Staff concludes that the project, including its linear facilities, will likely comply with all applicable site preparation LORS, and proposes Conditions of Certification (see below and the **Geology and Paleontology** section of this document) to ensure compliance.

MAJOR STRUCTURES, SYSTEMS AND EQUIPMENT

Major structures, systems and equipment are defined as those structures and associated components or equipment that are necessary for power production and are costly to repair or replace, that require a long lead time to repair or replace, or that are used for the storage, containment, or handling of hazardous or toxic materials. Major structures and equipment will be identified through compliance with proposed Condition of Certification **GEN-2** (below).

The AFC contains lists of the civil, structural, mechanical and electrical design criteria that demonstrate the likelihood of compliance with applicable engineering LORS, and that staff believes are essential to ensuring that the project is designed in a manner that protects public health and safety.

The project shall be designed and constructed to the 1998 edition of the California Building Code (CBC), and other applicable codes and standards in effect at the time design and construction of the project actually commence. In the event the initial designs are submitted to the Chief Building Official (CBO) for review and approval when the successor to the 1998 CBC is in effect, the 1998 CBC provisions, identified herein, shall be replaced with the applicable successor 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 using the appropriate lateral force procedure, staff has included Proposed Condition of Certification **STRUC-1** (below), which in part requires review and approval by the CBO of the project owner’s proposed lateral force procedures prior to the start of construction.

NATURAL GAS PIPELINE

A new 1.4 mile natural gas pipeline will be constructed to provide fuel to the proposed facility. This pipeline may be owned by PG&E. The line will be operated and maintained

by PG&E or EAEC in accordance with U.S. Department of Transportation (DOT), Title 49, Code of Federal Regulations (CFR) Chapter 1, Part 192 "Transportation of Natural and other Gas by Pipeline: Minimum Federal Safety Standards," and the California Public Utilities Commission, General Order 112-E (CPUC GO 112-E). Compliance with these requirements will help mitigate the impacts of pipeline rupture by ensuring proper operation and maintenance of the line. Therefore, no mitigation beyond a pipeline operated and maintained to applicable regulations is necessary.

COMPLIANCE MONITORING

Under Section 104.2 of the CBC, the building official is authorized and directed to enforce all the provisions of the CBC. For all energy facilities certified by the Energy Commission, the Energy Commission is the building official and has the responsibility to enforce the code. In addition, the Energy Commission has the power to render interpretations of the CBC and to adopt and enforce rules and supplemental regulations to clarify the application of the CBC's provisions.

The Energy Commission's design review and construction inspection process is developed to conform to CBC requirements and ensure that all facility design Conditions of Certification are met. As provided by Section 104.2.2 of the CBC, the Energy Commission appoints experts to carry out the design review and construction inspections and act as delegate CBO on behalf of the Energy Commission. These delegates typically include the local building official and/or independent consultants hired to cover technical expertise not provided by the local official. The applicant, through permit fees as provided by CBC Sections 107.2 and 107.3, pays the costs of the reviews and inspections. While building permits in addition to the Energy Commission certification are not required for this project, in lieu the applicant consistent with CBC Section 107 pays permit fees, to cover the costs of reviews and inspections.

Engineering and compliance staff will invite the local building authority, Alameda County, or a third party engineering consultant, to act as CBO for the project. When an entity has been identified to perform the duties of CBO, Energy Commission staff will complete a Memorandum of Understanding (MOU) with that entity that outlines its roles and responsibilities and those of its subcontractors and delegates.

Staff has developed proposed Conditions of Certification to ensure public health and safety and compliance with engineering design LORS. Some of these conditions address the roles, responsibilities and qualifications of the applicant's engineers responsible for the design and construction of the project (proposed Conditions of Certification **GEN-1** through **GEN-8**). Engineers responsible for the design of the civil, structural, mechanical, and electrical portions of the project are required to be registered in California, and to sign and stamp each submittal of design plans, calculations, and specifications submitted to the CBO. These conditions require that no element of construction subject to CBO review and approval shall proceed without prior approval from the CBO. They also require that qualified special inspectors be assigned to perform or oversee special inspections required by the applicable LORS.

While the Energy Commission and delegate CBO have the authority to allow some flexibility in scheduling construction activities, these conditions are written to require that

no element of construction of permanent facilities subject to CBO review and approval, which would be difficult to reverse or correct, may proceed without prior approval of plans by the CBO. For those elements of construction that are not difficult to reverse and are allowed to proceed without approval of the plans, the applicant shall bear the responsibility to fully modify those elements of construction to comply with all design changes that result from the CBO's plan review and approval process.

FACILITY CLOSURE

The removal of a facility from service, or decommissioning, as a result of the project reaching the end of its useful life, may range from "mothballing" to removal of all equipment and appurtenant facilities and restoration of the site. Future conditions that may affect the decommissioning decision are largely unknown at this time.

In order to assure that decommissioning of the facility will be completed in a manner that is environmentally sound, safe, and will protect public health and safety, the applicant shall submit a decommissioning plan to the Energy Commission for review and approval prior to the commencement of decommissioning. The plan shall include a discussion of the following items:

- proposed decommissioning activities for the project and all appurtenant facilities constructed as part of the project;
- all applicable LORS, local/regional plans, and the conformance of the proposed decommissioning activities to the 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.

The above requirements should serve as adequate protection, even in the unlikely event of project abandonment. Staff has proposed general conditions (see **General Conditions**) to ensure that these measures are included in the Facility Closure plan.

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

1. The laws, ordinances, regulations, and standards (LORS) identified in the AFC and supporting documents are those applicable to the project.

2. Staff has evaluated the proposed engineering LORS, design criteria and design methods, and concludes that the design, construction and eventual closure of the project will comply with applicable engineering LORS.

3. The Conditions of Certification proposed will ensure that the proposed facilities are designed and constructed in accordance with applicable engineering LORS. This will occur through the use of design review, plan checking and field inspections,

which are to be performed by the CBO or other Energy Commission delegate. Staff will audit the CBO to ensure satisfactory performance.

4. Whereas future conditions that may 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 General Conditions portion of this document prior to the commencement of decommissioning, the decommissioning procedure is likely to occur in compliance with all applicable engineering LORS.

RECOMMENDATIONS

Energy Commission staff recommends that:

1. The Conditions of Certification proposed herein be adopted to ensure that the project is designed and constructed to assure public health and safety, and to ensure compliance with all applicable engineering LORS;

2. The project be designed and built to the 1998 CBC (or successor standard, if such is in effect when the initial project engineering designs are submitted for review); and

3. The CBO shall review the final designs, conduct plan checking and perform field inspections during construction, and Energy Commission staff shall audit and monitor the CBO to ensure satisfactory performance.

CONDITIONS OF CERTIFICATION

GEN-1 The project owner shall design, construct and inspect the project in accordance with the 1998 California Building Code (CBC) and all other applicable engineering LORS in effect at the time initial design plans are submitted to the CBO for review and approval. (The CBC in effect is that edition that has been adopted by the California Building Standards Commission and published at least 180 days previously.) All transmission facilities (lines, switchyards, switching stations, and substations) are handled in Conditions of Certification in the **Transmission System Engineering** section of this document.

Protocol: In the event that the initial engineering designs are submitted to the CBO when a successor to the 1998 CBC is in effect, the 1998 CBC provisions identified herein 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.

Verification: Within 30 days after receipt of the Certificate of Occupancy, the project owner shall submit to the California Energy Commission Compliance Project Manager (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. The project owner shall provide the CPM a copy of the Certificate of Occupancy within 30 days of receipt from the CBO [1998 CBC, Section 109 – Certificate of Occupancy].

GEN-2 Prior to submittal of the initial engineering designs for CBO review, the project owner shall furnish to the CPM and to the CBO a schedule of facility design submittals, a Master Drawing List, and a Master Specifications List. The schedule shall contain a list of proposed submittal packages of designs, calculations, and specifications for major structures and equipment. To facilitate audits by Energy Commission staff, the project owner shall provide specific packages to the CPM when requested.

Verification: 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 rough grading, the project owner shall submit to the CBO and to the CPM the schedule, the Master Drawing List, and the 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 and equipment listed in **Table 1** below. Major structures and equipment shall be added to or deleted from the Table only with CPM approval. The project owner shall provide schedule updates in the Monthly Compliance Report.

Table 1: Major Structures and Equipment List

Equipment/System	Quantity (Plant)
Combustion Turbine (CT) Foundation and Connections	3
CT Mechanical Accessories (e.g. lube oil cooler, No_x control system, compressor wash system, fire detections system, fuel heating system, etc.) Foundation(s) and Connections	3
CT Structure Shell and Façade Foundation and Connections	3
CT Inlet and Filter Structure, Foundation and Connections	3
Combustion Turbine Generator (CTG) Foundation and Connections	3
Heat Recovery Steam Generator (HRSG) Structure, Foundation and Connections	3
HRSG Exhaust Stack, Foundation and Connections	3
HRSG Transition Duct Burner and Forced Draft Structure, Foundations and Connections	3
Selective Catalytic Reduction Unit Foundation and Connections	3
Steam Turbine Generator (STG) Foundation and Connections	1
STG Lube Oil Skid Foundation and Connections	1
STG Hydraulic Control System Foundation and Connections	1
Mechanical Draft Evaporative Cooling Tower, Support Structures, Foundations and Connections	1 Lot
Pipe and Cable Way Structures, Foundations and Connections	1 Lot
Electrical MCC, Building Structure, Foundation and Connections	1

Equipment/System	Quantity (Plant)
18KV Auxiliary Step-Down Transformer Foundation and Connections	2
230KV Step-Up Transformer, Fire Protection System Foundation and Connections	4
Load Center Transformers (4,160 to 480 Volt) Foundation(s) and Connections	1 Lot
125 VDC Power Supply System	1 Lot
Switchgear and Switchyard Equipment Foundation and Connections	1 Lot
Power Distribution Center Foundation and Connections	1 Lot
Generator – Natural Gas Fired 1,000 KW Emergency, Foundation and Connections	1
Natural Gas Filter/Scrubber/Separator Foundation and Connections	1 Lot
Natural Gas Separator/Heater Foundation and Connections	1 Lot
Natural Gas Metering and Regulating Station Foundations and Connections	1 Lot
All Building Structures, Foundations and Connections (e.g. Control Room, Administration Building, Warehouse, Bulk Storage Building, Equipment Shelter, etc.)	1 Lot
Tank – Ammonia Storage, Foundation and Connections	1
Tank – Raw/Fire Water, 5,000,000 Gallon, Foundation and Connections	2
Tank – Oily Water Separator, Foundation and Connections	1 Lot
Tank – Combustion Turbine Water, Foundation and Connections	1
Tank – Demineralized Water, 500,000 Gallon, Foundation and Connections	2
Tank – Boiler Blowdown, Foundation and Connections	1 Lot
Tanks – Water Treatment Facilities (e.g. Sulfuric Acid, Scale Inhibitor, Sodium Hypochlorite, Bromine, Non-Oxidizing Biocide, Oxygen Scavenger, Amine, Phosphate, etc.) Foundation and Connections (as required by CBC)	1 Lot
Pump – Fire Water Pump Skid (electric jockey pump, electric main pump, and diesel back-up pump) Foundation and Connections	1 Lot
Pump – HSRG Feedwater Foundation and Connections	6
Pump – Boiler Water Feed Pump Foundation and Connections	1 Lot
Pump – Demineralized Water Transfer Pump Foundation and Connections	1 Lot
Pump – Condensate Pump Foundation and Connections	3
Pump – Circulating Water Foundation and Connections	2
Pumps – Water Treatment and Cooling Systems (e.g. Auxiliary Cooling Water, Aqueous Ammonia Transfer, Aqueous Ammonia Unloading, Closed Loop Cooling Water, Oily Water Sump, Raw Water, Sulfuric Acid, Scale Inhibitor, Sodium Hypochlorite, Bromine, Non-Oxidizing Biocide, Oxygen	1 Lot

Equipment/System	Quantity (Plant)
Scavenger, Amine, Phosphate, etc.) Foundation and Connections (as required by CBC)	
Boiler – Auxiliary, Stack, Foundation and Connections	1
Auxiliary Boiler SCR System Foundation and Connections	1 Lot
Ammonia Injection Skid Foundation and Connections	1 Lot
Air Compressors Foundation(s) and Connections	1 Lot
Water Treatment Facilities Building, Foundation and Connections	1 Lot
Pipeline – Water Supply	1
Pipeline – Recycled Water Supply	1
Pipeline – Natural Gas	1
Potable Water Systems	1 Lot
Fire Suppression Systems	1 Lot
Drainage Systems (including sanitary, storm drain, and waste)	1 Lot
Waste Water Evaporation Ponds (5 Acres Each)	2
Building Energy Conservation Systems	1 Lot
Temperature Control and Ventilation Systems (including water and sewer connections)	1 Lot
High Pressure Piping	1 Lot
HVAC and Refrigeration Systems	1 Lot

GEN-3 The project owner shall make payments to the CBO for design review, plan check and construction inspection 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 1998 CBC [Chapter 1, Section 107 and Table 1-A, Building Permit Fees; Appendix Chapter 33, Section 3310 and Table A-33-A, Grading Plan Review Fees; and Table A-33-B, Grading Permit Fees], 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 as otherwise agreed 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 the applicable fees have been paid.

GEN-4 Prior to the start of rough grading, the project owner shall assign a California registered architect, structural engineer or civil engineer, as a resident engineer (RE), to be in general responsible charge of the project [Building Standards Administrative Code (Cal. Code Regs., tit. 24, § 4-209, Designation of Responsibilities).] All transmission facilities (lines, switchyards, switching stations, and substations) are handled in 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 each part is clearly defined as a distinct unit. Separate assignment of general responsible charge may be made for each designated part.

Protocol: The RE shall:

1. Monitor construction progress of work requiring CBO design review and inspection to ensure compliance with LORS;

2. Ensure that construction of all the facilities subject to CBO design review and inspection conforms in every material respect to the applicable LORS, these Conditions of Certification, approved plans, and specifications;

3. Prepare documents to initiate changes in the approved drawings and specifications when directed by the project owner or as required by conditions on the project;

4. Be responsible for providing the project inspectors and testing agency (ies) with complete and up-to-date set(s) 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 as not conforming to the approved plans and specifications.

The RE shall have the authority to halt construction and to require changes or remedial work, if the work does not conform to applicable 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.

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 rough grading, the project owner shall submit to the CBO for review and approval, the name, qualifications 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) are 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.

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) 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; D) a mechanical engineer; and E) an electrical engineer. [California Business and Professions Code section 6704 et seq., and sections 6730 and 6736 requires 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 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 (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.

Protocol: 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 [1998 CBC, Section 104.2, Powers and Duties of Building Official].

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.

Protocol: A: The civil engineer shall:

1. Design, or be responsible for design, 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

2. 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 in the construction procedures.

Protocol: B: The geotechnical engineer or civil engineer, experienced and knowledgeable in the practice of soils engineering, shall:

1. Review all the engineering geology reports, and prepare final soils grading report;

2. Prepare the soils engineering reports required by the 1998 CBC, Appendix Chapter 33, Section 3309.5 – Soils Engineering Report, and Section 3309.6 – Engineering Geology Report;

3. Be present, as required, during site grading and earthwork to provide consultation and monitor compliance with the requirements set forth in the 1998 CBC, Appendix Chapter 33, section 3317, Grading Inspections;

4. Recommend field changes to the civil engineer and RE;

5. Review the geotechnical report, field exploration report, laboratory tests, and engineering analyses detailing the nature and extent of the site soils that may be susceptible to liquefaction, rapid settlement or collapse when saturated under load; and

6. Prepare reports on foundation investigation to comply with the 1998 CBC, Chapter 18 section 1804, Foundation Investigations.

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 [1998 CBC, section 104.2.4, Stop orders].

Protocol: C: 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 LORS;

4. Evaluate and recommend necessary changes in design; and

5. Prepare and sign all major building plans, specifications and calculations.

Protocol: D: 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 with all of the mechanical engineering design requirements set forth in the Energy Commission's Decision.

Protocol: E: 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.

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 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.

GEN-6 Prior to the start of an activity requiring special inspection, 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 1998 CBC, Chapter 17, Section 1701, Special Inspections, Section, 1701.5 Type of Work (requiring special inspection), and Section 106.3.5, Inspection and observation program. All transmission facilities (lines, switchyards, switching stations, and substations) are handled in Conditions of Certification in the **Transmission System Engineering** section of this document.

Protocol: 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. Observe 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 and specifications and the applicable provisions of the applicable edition of the CBC.

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).

Verification: At least 15 days 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 The project owner shall keep the CBO informed regarding the status of engineering and construction. If any discrepancy in design and/or construction is discovered in any work that has undergone CBO design review and approval, the project owner shall document the discrepancy and recommend the corrective action required. 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, the 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. When the work and the "as-built" and "as graded" plans conform to the approved final plans, the project owner shall notify the CPM regarding the CBO's final approval. The marked up "as-built" drawings for the construction of structural and architectural work shall be submitted to the CBO. Changes approved by the CBO shall be identified on the "as-built" drawings [1998 CBC, Section 108, Inspections]. The project owner shall retain one set of approved engineering plans, specifications and calculations at the project site or at another accessible location during the operating life of the project [1998 CBC, Section 106.4.2, Retention of plans].

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 final approved engineering plans, specifications and calculations as described above, the project owner shall submit to the CPM a letter stating that the above documents have been stored and indicate the storage location of such documents.

CIVIL-1 Prior to the start of site grading, 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. Related calculations and specifications, signed and stamped by the responsible civil engineer; and

4. Soils report as required by the 1998 CBC [Appendix Chapter 33, Section 3309.5, Soils Engineering Report and Section 3309.6, Engineering Geology Report].

Verification: At least 15 days prior to the start of site grading (or a lesser number of days mutually agreed to by the project owner and the CBO), 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 earthworks and construction in the affected areas when the responsible geotechnical engineer or 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 [1998 CBC, Section 104.2.4, Stop orders].

Verification: The project owner shall notify the CPM, within five days, when earthwork and construction is stopped as a result of unforeseen adverse geologic/soil conditions. Within five days 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 1998 CBC, Chapter 1, Section 108, Inspections; Chapter 17, Section 1701.6, Continuous and Periodic Special Inspection; and Appendix Chapter 33, Section 3317, Grading Inspection. All plant site grading operations for which a grading permit is required shall be subject to inspection by the CBO.

Protocol: 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 detailing all discrepancies and non-compliance items, and the proposed corrective action, and send copies to the CBO and the CPM.

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. 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 facilities, the project owner shall obtain the CBO's approval of the final "as-graded" grading plans, and final "as-built" plans for the erosion and sedimentation control facilities [1998 CBC, Section 109, Certificate of Occupancy].

Verification: Within 30 days of the completion of the erosion and sediment control mitigation and drainage facilities, the project owner shall submit to the CBO 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. The project owner shall submit a copy of this report to the CPM in the next Monthly Compliance Report.

STRUC-1 Prior to the start of any increment of construction of any major structure or component listed in **Table 1** of Condition of Certification **GEN-2**, above, the project owner shall submit to the CBO for design review and approval the proposed lateral force procedures for project structures and the applicable designs, plans and drawings for project structures. Proposed lateral force procedures, designs, plans and drawings shall be those for the following items (from **Table 1**, above):

1. Major project structures;

2. Major foundations, equipment supports and anchorage;

3. Large field fabricated tanks;

4. Turbine/generator pedestal; and

5. Switchyard structures.

Construction of any structure or component shall not commence until the CBO has approved the lateral force procedures to be employed in designing that structure or component.

Protocol: 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 (i.e., 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 [1998 CBC, Section 108.4, Approval Required];
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 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 on-site fabrication and installation of each structure, equipment support, or foundation [1998 CBC, Section 106.4.2, Retention of plans and Section 106.3.2, Submittal documents]; and

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 [1998 CBC, Section 106.3.4, Architect or Engineer of Record].

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 any increment of construction of any structure or component listed in **Table 1** of Condition of Certification **GEN-2**, the project owner shall submit to the CBO, with a copy to the CPM, the responsible design engineer's signed statement that the final design plans, specifications and calculations conform with all of the requirements set forth in the Energy Commission's Decision.

If the CBO discovers non-conformance with the stated requirements, the project owner shall resubmit the corrected plans to the CBO within 20 days of receipt of the nonconforming submittal with a copy of the transmittal letter to the CPM.
The project owner shall submit to the CPM a copy of a statement from the CBO that the proposed structural plans, specifications, and calculations have been approved and are in conformance with the requirements set forth in the applicable 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 1998 CBC, Chapter 17, Section 1701, Special Inspections, Section 1701.5, Type of Work (requiring special inspection), Section 1702, Structural Observation and Section 1703, Nondestructive Testing.

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 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 1998 CBC, Chapter 1, Section 106.3.2, Submittal documents, and Section 106.3.3, Information on plans and specifications, including the revised drawings, specifications, calculations, and a complete description of, and supporting rationale for, the proposed changes, and shall give 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 Chapter 3, Table 3-E of the 1998 CBC shall, at a minimum, be designed to comply with Occupancy Category 2 of the 1998 CBC.

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 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 Prior to the start of any increment of major piping or plumbing construction, 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 **Table 1**, Condition of Certification **GEN-2**, above. Physical layout drawings and drawings not related to code compliance and life safety need not be submitted. 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 said construction [1998 CBC, Section 106.3.2, Submittal Documents, Section

108.3, Inspection Requests, Section 108.4, Approval Required; 1998 California Plumbing Code, Section 103.5.4, Inspection Request, Section 301.1.1, Approval].

Protocol: The responsible mechanical engineer shall stamp and sign all plans, drawings and calculations for the major piping and plumbing systems subject to the CBO design review and approval, and submit a signed statement to the CBO when the said proposed piping and plumbing systems have been designed, fabricated and installed in accordance with all of the applicable laws, ordinances, regulations and industry standards [Section 106.3.4, Architect or Engineer of Record], which may include, but not be 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);
- 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
- Specific City/County code(s).

The CBO may deputize inspectors to carry out the functions of the code enforcement agency [1998 CBC, Section 104.2.2, Deputies].

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 any increment of major piping or plumbing construction listed in **Table 1**, Condition of Certification **GEN-2** above, 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 the 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 the 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 said installation [1998 CBC, Section 108.3 – Inspection Requests].

Protocol: 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 a lesser number of days mutually agreed to by the project owner and the CBO) 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 Prior to the start of construction of any heating, ventilating, air conditioning (HVAC) or refrigeration system, the project owner shall submit to the CBO for design review and approval the design plans, specifications, calculations and quality control procedures for that system. Packaged HVAC systems, where used, shall be identified with the appropriate manufacturer's data sheets.

Protocol: 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 said 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 [1998 CBC, Section 108.7, Other Inspections; Section 106.3.4, Architect or Engineer of Record].

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 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 electrical equipment and systems 480 volts and higher, listed below, with the exception of underground duct work and any physical layout drawings and drawings not related to code compliance and life safety, the project owner shall submit, for CBO design review and approval, the proposed final design, specifications and calculations [CBC 1998, Section 106.3.2, Submittal documents]. 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 [1998 CBC, Section 108.4, Approval Required, and Section 108.3, Inspection Requests]. All transmission facilities (lines, switchyards, switching stations, and substations) are handled in Conditions of Certification in the **Transmission System Engineering** section of this document.

Protocol: A. Final plant design plans to include:

1. one-line diagrams for the 13.8 kV, 4.16 kV and 480 V systems; and
2. system grounding drawings.

Protocol: B. Final plant calculations to establish:

2. Short-circuit ratings of plant equipment;
3. ampacity of feeder cables;
4. Voltage drop in feeder cables;
5. System grounding requirements;
6. Coordination study calculations for fuses, circuit breakers and protective relay settings for the 13.8 kV, 4.16 kV and 480 V systems;
7. System grounding requirements; and
8. Lighting energy calculations.

Protocol: C. The following activities shall be reported to the CPM in the Monthly Compliance Report:

- receipt or delay of major electrical equipment;
- testing or energization of major electrical equipment; and
- 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 a lesser number of days mutually agreed to by the project owner and the CBO) 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

EAEC (East Altamont Energy Center) 2001a. Application for Certification, Volume 1 & Appendices, East Altamont Energy Center (01-AFC-4). Dated March 20, 2001 and docketed March 29, 2001.

EAEC (East Altamont Energy Center) 2001e. Data Adequacy Response Set 1. Dated and docketed May 1, 2001.

GEOLOGY AND PALEONTOLOGY

Dr. Dal Hunter

INTRODUCTION

The geology and paleontology section discusses the project's potential impacts regarding geological hazards, geological and paleontological resources, and surface water hydrology. The purpose of this analysis is to verify that the applicable laws, ordinances, regulations, and standards (LORS) have been identified and that the project can be designed and constructed in accordance with all applicable LORS, and in a manner that protects environmental quality and assures public health and safety. Energy Commission staff's objective is to ensure that there will be no significant adverse impacts to significant geological and paleontological resources, and surface water hydrology during project construction, operation and closure. The section concludes with staff's proposed monitoring and mitigation measures with respect to geological hazards, geological, and paleontological resources and surface water hydrology, with the inclusion of Conditions of Certification.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

The applicable LORS are listed in the AFC, in sections 8.14, 8.15 and 8.16 (EAEC, 2001a). A brief description of the LORS for surface water hydrology is presented in the **Water Resources** section of the staff assessment. A brief description of the LORS for paleontological resources, and geological hazards and resources follows.

FEDERAL

The proposed East Altamont Energy Center (EAEC) is not located on Federal property but will be interconnected to a federally owned substation. There are no federal LORS for geological hazards and resources or grading for the proposed project. The Federal Antiquities Act of 1906 (PL 59-209; 16 United States Code 431 *et seq*.; 34 Stat. 25), in part, protects paleontological resources from vandalism and unauthorized collection on federal land. The National Environmental Policy Act of 1968, as amended, requires analysis of potential environmental impacts to important historic, cultural and natural aspects of our national heritage (United States Code, Section 4321 4327; 40 Code of Federal Regulations, Section 1502.25).

STATE AND LOCAL

The California Building Code (CBC) 1998 edition is based upon the *Uniform Building Code* (*UBC*), 1997 edition, which was published by the International Conference of Building Officials. The *CBC* is a series of standards that are used in investigation, design (Chapters 16 and 18) and construction (including grading and erosion control; Appendix Chapter 33). The *CBC* supplements the grading and construction requirements of the *UBC*.

The California Environmental Quality Act (CEQA) Guidelines Appendix G provides a checklist of questions that a lead agency should normally address if relevant to a project's environmental impacts.

- Section (V) (c) asks if the project will directly or indirectly destroy a unique paleontological resource or site or unique geological feature.
- Sections (VI) (a), (b), (c), (d), and (e) pose questions that are focused on whether or not the project would expose persons or structures to geological hazards.
- Sections (X) (a) and (b) pose questions about the project's effect on mineral resources.

The Measures for Assessment and Mitigation of Adverse Impacts to Non-renewable Paleontologic Resources: Standard Procedures (Society of Vertebrate Paleontologists 1994) is a set of procedures and standards for assessing and mitigating impacts to vertebrate paleontological resources. They were adopted in October 1994 by The Society of Vertebrate Paleontologists (SVP), a national organization.

ENVIRONMENTAL SETTING

The East Altamont Energy Center (EAEC) will be located on the western edge of the San Joaquin Valley within the Great Valley geomorphic province at 37.803 degrees north latitude by 121.574 degrees west longitude. The project site is in the extreme northeast corner of Alameda County, along the southwestern edge of the Sacramento-San Joaquin River Delta. The 55-acre site is flanked to the north by Byron Bethany Road and to the south by Kelso Road. The Western Area Power Administration (Western) Tracy Substation lies across Mountain House Road to the southwest while undeveloped agricultural land occurs to the east.

The project will involve the design, construction and operation of an 820 megawatt (M_W) natural-gas-fired combined-cycle generating plant, augmented by 267 M_W of duct firing. A 230-kilovolt (kV) switchyard and approximately 0.5 mile of new 230-kV transmission line will be necessary. The switchyard, which will be owned by Western, will function as an extension of the Tracy substation. Natural gas for the facility will be delivered via approximately 1.4 miles of new 20-inch pipeline that will connect to Pacific Gas and Electric's (PG&E) existing gas transmission line west of the site. Raw water for cooling tower and process makeup water will be supplied by Byron Bethany Irrigation District (BBID) via a 2.1-mile pipeline.

The project is not crossed by any known active faults. The depth to ground water can vary from 0 to 10 feet below existing grade. Groundwater movement is very slow due to lack of irrigation pumping, permeability, and the high water table in the Delta (Hill and Associates, 1964). Site near-surface geology consists of alluvial fan deposits of Holocene age underlain by semi-consolidated deposits of Pliocene-Pleistocene age. The unconsolidated alluvium consists of highly variable gravel, sand, silt and clay units deposited in fans extending from the nearby Coast Range Mountains. The underlying semi-consolidated deposits consist of weakly cemented conglomerate, sandstone and siltstone.

The project site lies at an elevation of approximately 40 feet above mean sea level. Existing grade at the power plant site slopes approximately one percent to the north. The existing site drainage is sheet flow in nature. A more complete discussion of on-site drainage is included in the **Water Resources** section of this staff assessment

ANALYSIS AND IMPACTS

GEOLOGICAL HAZARDS

Faulting and Seismicity

The project is located within seismic zone 4 as delineated on Figure 16-2 of the 1998 edition of the *CBC.* Energy Commission staff reviewed the Fault Activity Map of California and Adjacent Areas with Locations and Ages of Recent Volcanic Eruptions, dated 1994 (CDMG 1994). No active faults have been identified within the power plant footprint. A number of active faults lie within a 25-mile radius of the site. All of these faults are classified as Type B seismic sources, as defined in the 1997 *UBC* and the *CBC* (1998). These codes define 3 seismic source types: A, B, and C. Type A faults, such as the San Andreas Fault System, are those with an average annual slip rate greater than 5 mm per year and the potential to generate a moment magnitude (M_w) earthquake of at least 7.0. Type C faults are those with a slip rate of 2 mm or less per year and a maximum moment earthquake of less than 6.5. Type B faults, the largest grouping, are all active faults not defined as Type A or C.

The closest active faults to the project are the Midway Fault Zone (3.5 miles southwest of the EAEC) and the Vernalis fault (5.0 miles east of the EAEC). The Midway Fault Zone is considered the northwest extension of the San-Joaquin Fault Zone and both are considered segments of the Great Valley Thrust Fault Zone (GVTFZ). The GVTFZ extends from Red Bluff in northern California to northwest of Bakersfield in the southern San Joaquin Valley. The Midway Fault Zone has the potential to generate a maximum credible earthquake (MCE) of (M_w) 6.75. The Vernalis fault is a northwest-trending fault that has had displacement within Holocene time and a calculated MCE of M_w 7.5. Other faults near the project site include the Midland fault, the Greenville fault and the Calaveras fault. The Midland fault is located 6 miles north of the project site though recurrence interval and MCE are unknown. The Greenville fault is 9 miles southwest of the EAEC site and right-lateral displacement has occurred within Holocene time. The displacement rate on the Greenville fault is calculated at 2.0 millimeters per year and the MCE is M_w 6.9. The Calaveras fault is located 21 miles west of the EAEC site and has a calculated right-lateral displacement rate of 6 mm/yr. The MCE for the Calaveras fault is M_w 6.9.

The applicant estimates that the peak horizontal ground acceleration for the design earthquake (with a 10 percent probability in 50 year return interval) is 0.46g [“g” is standard terminology] (EAEC, 2001a, page 8.15-5). This is based on a 6.75 M_w earthquake along the Midway-San Joaquin fault. A peak horizontal ground acceleration of this intensity could cause instability and liquefaction of EAEC foundation soils, depending on the soil conditions actually present. Seismic concerns will be addressed as a result of proposed Condition of Certification **GEN-1**. Proper design in accordance with this condition should adequately mitigate seismic hazards to the current standards of practice.

Liquefaction, Hydrocompaction, Subsidence, and Expansive Soils

Liquefaction is a condition in which a cohesionless or even slightly plastic soil may lose shear strength due to a sudden increase in pore water pressure. Four of the parameters used to assess the potential for liquefaction are the density, depth to groundwater, texture, and the peak horizontal ground acceleration estimated for the site. The depth to ground

water at the project is approximately 0 to 10 feet below existing grade. The applicant has estimated that the peak horizontal ground acceleration for the design earthquake (with a 10% chance in 50 year return interval) is 0.46g, which may be high enough, when combined with the shallow ground water and locally loose sands, to trigger liquefaction at the project site. The Applicant has acknowledged that the site is located in an area with generally high liquefaction potential. The project site is located directly adjacent to an area mapped as liquefaction hazard zone (Contra Costa County, 1996). Energy Commission staff recommends that the Applicant conduct a detailed liquefaction analysis of the project site and linear facilities prior to the completion of the final design for the project.

Hydrocompaction is the process of the loss of soil volume upon the application of water. The potential for significant compaction due to hydrocompaction is considered remote since the ground water table at the site is shallow.

Subsidence of surficial and near surface soil units may be induced at the site by either strong ground shaking due to a large nearby earthquake, by consolidation of loose or soft soils due to heavy loading of the soils by large structures, or by the extraction of fluids from the subsurface. The Applicant has stated that no known subsidence problems exist in the project area, though the presence of loose or soft soils at the site has not yet been determined. Energy Commission staff recommends that the Applicant conduct a detailed geotechnical analysis of the project site and linear facilities prior to the completion of the final design for the project.

Soils that contain a high percentage of expansive clay minerals are prone to expansion, if subjected to an increase in water content. Expansive soils are usually measured with an index test such as the expansive index potential. In order for a soil to be a candidate for testing, the soil must have a high clay content and the clay must have a high shrink-swell potential and a high plasticity index. No test results for the shrink-swell potential, expansive index potential, or the consolidation or bearing capacity of the soils have been submitted to the Energy Commission. The Applicant has indicated in the AFC that expansive clay soils may be present under both the linear facilities and the EAEC site. Prior to the final design of the foundation for the SCR, the Applicant should have a foundation investigation report conducted and reviewed by the CBO at the time that the construction plans for the SCR are to be reviewed by the CBO. Conditions of Certification **GEN-1, GEN-5** and **CIVIL-1** should mitigate the above hazards to a less than significant level.

landslides

The EAEC site is essentially flat and is located over one mile from the nearest mountain. Since no significant excavation is planned during site construction, the potential for impact from landslides at the site is considered nonexistent.

GEOLOGICAL AND PALEONTOLOGICAL RESOURCES

The project location is designated as Mineral Resources Zone-3, an area of undetermined mineral resources potential (CDMG Special Report 143). No mineral resources are known to have been identified at the present site and there are no significant sand or gravel mines in the area.

Energy Commission staff has reviewed the paleontological resources technical report (East Altamont, 2001a, AFC Appendix L and section 8.16). The site can be divided into

two lithologically similar units. Both have yielded significant finds of vertebrate fossils in other areas of Alameda County, but neither is known to have shown fossils at the proposed EAEC site. The older unit, the Tulare Formation, is thought to be Late Pleistocene to Pleistocene in age and is slightly tilted, which aids in differentiating the Tulare Formation from the younger, overlying and flat-lying Quaternary Alluvial deposits. The Quaternary Alluvial deposits occur near the ground surface and will be disturbed by construction activities, both at the plant site and along the linear support facilities. Most of the area has been cultivated for many years, so that the upper foot or so has already been severely disturbed. Deeper excavations will encounter undisturbed zones of the Quaternary Alluvium and, possibly, the underlying Tulare Formation. Energy Commission staff has proposed Conditions of Certification, below, that will enable the applicant to mitigate impacts upon paleontological resources to a less than significant level should they be encountered during construction, operation, and closure of the project.

SURFACE WATER HYDROLOGY

The rainy season at the EAEC site is typical of the central Sacramento Valley, extending from November through March. Summer months are typically dry with occasional thunderstorms and minor rain sometimes occurring during the spring and fall. The average annual precipitation for the site is about 12 inches, based on records from the nearby Tracy area.

The project lies outside the 100-year flood zone, as designated by the Federal Emergency Management Agency (FEMA, 2000). The EAEC site is located near the confluent of two major rivers, as well as diversion facilities for both the Central Valley Project and the California State Water Project.

Storm water runoff across the project site currently runs to the north by sheet flow to be collected in an east/west drainage ditch. This ditch discharges into a drain along the east side of the property that flows to the north, ultimately discharging into the intake channel of the Delta-Mendota Canal. The area is currently cultivated with soils that reportedly have poor drainage. The applicant has calculated the total runoff from the 23.7-acre site as approximately 1 million gallons for the 100-year storm in 24 hours, and 746,000 gallons for the 10-year storm, again for a 24-hour period. Table 8-14-7 indicates that the post-construction runoff is nearly double that of the pre-construction storm water runoff for the 23.7-acre site, with a maximum of 1.8 million gallons for the 100-year storm. Following construction, storm water will drain to a storm water detention pond via a system of drains, channels, and pipes. The applicant indicates that the peak post-construction storm water discharge will be less than peak pre-construction discharge because of regulation by the detention pond. For the remainder of the 55-acre site, development will decrease total runoff since some of the runoff will be captured in the wastewater recycle pond, cooling tower, and the evaporation ponds. The applicant has proposed the use of Best Management Practices (BMPs) for erosion and sediment control in order to avoid polluting surface waters during construction. Setbacks incorporated in the design, BMPs, and on-site drainage structures will be designed to protect local surface water from water quality impacts. Condition of Certification **CIVIL-1,** along with specific conditions presented under **Water Resources**, are expected to mitigate surface water impacts to less than significant levels.

SITE SPECIFIC IMPACTS

No known geological resources will be impacted by the construction and operation of the project. The (confidential) Paleontological Resources technical Report (EAEC, 2001a; Appendix 8.16) assigns ratings of "Highly Sensitive" to both of the geologic units that may underlie the cultivated surface soils at this site. No vertebrate fossils are known to have been found at the project site. Since there is to be considerable grading, Energy Commission staff believes there is a moderate probability of encountering paleontological resources. The recommended Conditions of Certification **PAL-1 through PAL-7** are expected to mitigate potential geologic/paleontologic impacts to less than significant levels.

CUMULATIVE IMPACTS

The EAEC lies in an area of no known or likely geologic resources such as minerals, aggregates, oil or natural gas. In the event that paleontological resources are revealed during grading, a mitigation plan will be in place to assure proper protection and recovery. Increased surface water from construction of impermeable surfaces can be handled by a properly designed surface water drainage system.

As a consequence of the above factors, it is staff's opinion that the potential for a significant adverse cumulative impact on paleontological resources, geological resources, or surface water hydrology is unlikely, if the project is constructed according to the recommended Conditions of Certification.

FACILITY CLOSURE

A definition and general approach to closure is presented in the **General Conditions** section of this document. Facility closure activities are not anticipated to impact geological or paleontological resources. This is due to the fact that no paleontological or geological resources are known to exist at the power plant location. In addition, decommissioning and closure of the power plant should not negatively affect geological or paleontological resources since the majority of the ground disturbed in plant decommissioning and closure would have been disturbed in the construction and operation of the plant. Surface water hydrology impacts will depend upon the closure activities proposed.

RESPONSE TO PUBLIC AND AGENCY COMMENTS

Energy Commission staff have received no comments regarding geology, paleontology or surface water from City, County, State, or Federal agencies at this time. One comment from the public, designated as **G&DK**-10" are asked "How close to the center of the earthquake fault is this area?" Earthquake faults are discussed above under **Faulting and Seismicity**. The nearest fault to the site is the Midway Fault, 3.5 miles to the southwest.

MITIGATION

As mitigation for potential impacts to geological hazards, surface water hydrology and paleontological resources staff proposes the Conditions of Certification presented below.

CONCLUSIONS AND RECOMMENDATIONS

The project should have no adverse impact on geological and paleontological resources and surface water hydrology. Staff proposes to assure compliance with applicable LORS for geological hazards and surface water hydrology, staff proposes the Conditions of Certification listed below.

PROPOSED CONDITIONS OF CERTIFICATION

General Conditions of Certification with respect to Geology are covered under Conditions of Certification **GEN-1**, **GEN-5**, and **CIVIL-1** in the **FACILITY DESIGN** section. Conditions of Certification related to paleontological resources are presented below:

PAL-1 Prior to ground disturbance, the project owner shall ensure that the designated paleontological resource specialist approved by the CPM is available for field activities and prepared to implement the Conditions of Certification.

The designated paleontological resources specialist shall be responsible for implementing all the paleontological Conditions of Certification and for using qualified personnel to assist in this work.

Protocol: The project owner shall provide the CPM with the name and statement of qualifications for the designated paleontological resource specialist.

The statement of qualifications for the designated paleontological resource specialist shall demonstrate that the specialist meets the following minimum qualifications: a degree in paleontology or geology or paleontological resource management; and at least three years of paleontological resource mitigation and field experience in California, including at least one year's experience leading paleontological resource mitigation and field activities.

The statement of qualifications shall include a list of specific projects the specialist has previously worked on; the role and responsibilities of the specialist for each project listed; and the names and phone numbers of contacts familiar with the specialist's work on these referenced projects.

If the CPM determines that the qualifications of the proposed paleontological resource specialist do no satisfy the above requirements, the project owner shall submit another individuals name and qualifications for consideration.

If the approved, designated paleontological resource specialist is replaced prior to completion of project mitigation, the project owner shall obtain CPM approval of the new designated paleontological resource specialist by submitting the name and qualifications of the proposed replacement to the CPM, at least ten (10) days prior to the termination or release of the preceding designated paleontological resource specialist.

Should emergency replacement of the designated specialist become necessary, the project owner shall immediately notify the CPM to discuss the qualifications of its proposed replacement specialist.

Verification: At least ninety (90) days prior to site mobilization, the project owner shall submit the name, resume, and the availability of its designated paleontological resource specialist, to the CPM for review and approval. The CPM shall provide approval or disapproval of the proposed paleontological resource specialist.

At least ten (10) days prior to the termination or release of a designated paleontological resource specialist, the project owner shall obtain CPM approval of the replacement specialist by submitting to the CPM the name and resume of the proposed new designated paleontological resource specialist. Should emergency replacement of the designated specialist become necessary, the project owner shall immediately notify the CPM to discuss the qualifications of its proposed replacement specialist.

PAL-2 Prior to site mobilization, the designated paleontological resource specialist shall prepare a Paleontological Resources Monitoring and Mitigation Plan to identify general and specific measures to minimize potential impacts to sensitive paleontological resources, and submit this plan to the CPM for review and approval. After CPM approval, the project owner's designated paleontological resource specialist shall be available to implement the Monitoring and Mitigation Plan, as needed, throughout the project construction.

Protocol: The Paleontological Resources Monitoring and Mitigation Plan to be developed in accordance with the guidelines of the Society of the Vertebrate Paleontologists (SVP, 1994) shall include, but not be limited to, the following elements and measures:
A discussion of the sequence of project-related tasks, such as any pre-construction surveys, fieldwork, flagging or staking; construction monitoring; mapping and data recovery; fossil preparation and recovery; identification and inventory; preparation of final reports; and transmittal of materials for curation;

Identification of the person(s) expected to assist with each of the tasks identified within this condition for certification, and a discussion of the mitigation team leadership and organizational structure, and the inter-relationship of tasks and responsibilities;

Where monitoring of project construction activities is deemed necessary, the extent of the areas where monitoring is to occur and a schedule for the monitoring;

An explanation that the designated paleontological resource specialist shall have the authority to halt or redirect construction in the immediate vicinity of a vertebrate fossil find until the significance of the find can be determined;

A discussion of equipment and supplies necessary for recovery of fossil materials and any specialized equipment needed to prepare, remove, load, transport, and analyze large-sized fossils or extensive fossil deposits;

Inventory, preparation, and delivery for curation into a retrievable storage collection in a public repository or museum, which meets the Society of Vertebrate Paleontologists standards and requirements for the curation of paleontological resources; and

Identification of the institution that has agreed to receive any data and fossil materials recovered during project-related monitoring and mitigation work, discussion of any 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.

Verification: At least sixty (60) days prior to site mobilization on the project, the project owner shall provide the CPM with a copy of the Paleontological Resources Monitoring and Mitigation Plan prepared by the designated paleontological resource specialist for review and approval. If the plan is not approved, the project owner, the designated paleontological resource specialist, and the CPM shall meet to discuss comments and necessary changes.

PAL-3 Prior to ground disturbance, and throughout the project construction period, as needed for all new employees, the project owner and the designated paleontological resource specialist shall prepare and conduct CPM-approved training for all project managers, construction supervisors, and workers who operate ground disturbing equipment. The project owner and construction manager shall provide the workers with the CPM-approved set of procedures for reporting any sensitive paleontological resources or deposits that may be discovered during project-related ground disturbance.

Protocol: The paleontological training program shall discuss the potential to encounter paleontological resources in the field, the sensitivity and importance of these resources, and the legal obligations to preserve and protect such resources.

The training shall also include the set of reporting procedures that workers are to follow if paleontological resources are encountered during project activities. The training program shall be presented by the designated paleontological resource specialist and may be combined with other training programs prepared for cultural and biological resources, hazardous materials, or any other areas of interest or concern.

Verification: At least thirty (30) days prior to site mobilization, the project owner shall submit to the CPM for review, comment, and written approval, the proposed employee training program and the set of reporting procedures the workers are to follow if paleontological resources are encountered during project construction.

If the employee training program and set of procedures are not approved, the project owner, the designated paleontological resource specialist, and the CPM shall meet to discuss comments and necessary changes, before the beginning of construction.

Documentation for training of additional new employees shall be provided in subsequent Monthly Compliance Reports, as appropriate.

PAL-4 The designated paleontological resource specialist shall be present at all times he or she deems appropriate to monitor construction-related grading, excavation,

trenching, and/or augering in areas where potentially fossil-bearing sediments have been identified. If the designated paleontological resource specialist determines that full-time monitoring is not necessary in certain portions of the project area or along portions of the linear facility routes, the designated specialist shall notify the project owner.

Verification: The project owner shall include in the Monthly Compliance Reports a summary of paleontological activities conducted by the designated paleontological resource specialist.

PAL-5 The project owner, through the designated paleontological resource specialist, shall ensure the recovery, preparation for analysis, analysis, identification and inventory, the preparation for curation, and the delivery for curation of all significant paleontological resource materials encountered and collected during the monitoring, data recovery, mapping, and mitigation activities related to the project.

Verification: The project owner shall maintain in its compliance files copies of signed contracts or agreements with the designated paleontological resource specialist and other qualified research specialists who will ensure the necessary data and fossil recovery, mapping, preparation for analysis, analysis, identification and inventory, and preparation for delivery of all significant paleontological resource materials collected during data recovery and mitigation for the project. The project owner shall maintain these files for a period of three years after completion and approval of the CPM-approved Paleontological Resources Report and shall keep these files available for periodic audit by the CPM.

PAL-6 The project owner shall ensure preparation of a Paleontological Resources Report by the designated paleontological resource specialist. The Paleontological Resources Report shall be completed following completion of the analysis of the recovered fossil materials and related information. The project owner shall submit the paleontological report to the CPM for approval.

Protocol: The report shall include (but not be limited to) a description and inventory list of recovered fossil materials; a map showing the location of paleontological resources encountered; determinations of sensitivity and significance; and a statement by the paleontological resource specialist that project impacts to paleontological resources have been mitigated.

Verification: Within 90 days following completion of the analysis of the recovered fossil materials, the project owner shall submit a copy of the Paleontological Resources Report to the CPM for review and approval under a cover letter stating that it is a confidential document.

PAL-7 The project owner shall include in the facility closure plan a description regarding the potential for closure of the facility to impact paleontological resources. The conditions for closure will be determined when a facility closure plan is submitted to the CPM, twelve months prior to closure of the facility. If no activities are proposed that would potentially impact paleontological resources, then no mitigation measures for paleontological resource management are required in the facility closure plan.

Protocol: The closure requirements for paleontological resources are to be based upon the Paleontological Resources Report and the proposed grading activities for facility closure.

Verification: The project owner shall include a description of closure activities described above in the facility closure plan.

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POWER PLANT EFFICIENCY

Steve Baker

INTRODUCTION

The Energy Commission makes findings as to whether energy use by the East Altamont Energy Center (EAEC) will result in significant adverse impacts on the environment, as defined in the California Environmental Quality Act (CEQA). If the Energy Commission finds that the EAEC's consumption of energy creates 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 Energy Commission's findings, this analysis will:

- determine whether the facility will likely present any adverse impacts upon energy resources;
- determine whether these adverse impacts are significant; and if so,
- determine whether feasible mitigation measures exist that would eliminate the adverse impacts, or reduce them to a level of insignificance.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

FEDERAL

No federal laws apply to the efficiency of this project.

STATE

California Environmental Quality Act Guidelines

CEQA Guidelines state that the environmental analysis "…shall describe feasible measures which could minimize significant adverse impacts, including where relevant, 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).

LOCAL

No local ordinances apply to power plant efficiency.

SETTING

The applicant proposes to construct and operate the 1,100 MW (nominal gross output) merchant EAEC power plant to sell energy to the power market or directly to customers via short- and mid-term contracts (EAEC 2001a, AFC §§ 1.1, 2.2.16, 10.2.2, 10.3). (Note that this nominal rating is based upon preliminary design information and generating equipment manufacturers' guarantees. The project's actual maximum generating capacity may differ from this figure.) The AFC is not specific as to whether the plant in intended to supply baseload, load-following and/or peaking power, but in response to Energy Commission staff's queries, the applicant later clarified that the plant will provide both baseload and peaking power (EAEC 2001hh). Although the AFC described the EAEC as an 1,100 MW (nominal) combined cycle power plant, the project is actually an 820 MW combined cycle baseload power plant, with an additional 267 MW of peaking capacity provided by oversized duct burners and an oversized steam turbine generator (EAEC 2001hh). The applicant envisions operating at baseload up to 8,000 hours per year, and in combined baseload and peaking mode up to 5,080 hours per year (EAEC 2001a, AFC § 10.2.2).

The EAEC will consist of three General Electric PG7251(FB) combustion turbine generators with inlet air fogging systems and steam injection producing approximately 180 MW each at baseload conditions (no inlet air fogging or steam injection), three multi-pressure heat recovery steam generators (HRSGs) with duct burners, and one three-pressure, reheat, condensing steam turbine generator producing a maximum of 550 MW, arranged in a three-on-one combined cycle train, totaling approximately 1,090 MW. The gas turbines and HRSGs will be equipped with dry low-NOx combustors and selective catalytic reduction to control air emissions (EAEC 2001a, AFC §§ 1.1, 2.2.2, 2.2.3, 2.2.4, 2.2.4.1, 2.2.4.2, 2.2.4.3, 2.2.4.4, 2.4.2.1, 10.2.2; EAEC 2001ee). Natural gas will be delivered by the existing Pacific Gas & Electric (PG&E) backbone gas transmission Line 401 via a new 20-inch diameter 1.4-mile natural gas pipeline (EAEC 2001a, AFC §§ 1.1, 2.1, 2.4.3, 6.0, 6.1, 10.2.1).

ANALYSIS

ADVERSE IMPACTS ON ENERGY RESOURCES

The inefficient and unnecessary consumption of energy, in the form of non-renewable fuels such as natural gas and oil, constitutes an adverse environmental impact. An adverse impact can 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. The EAEC will burn natural gas at a nominal rate of

120 billion Btu per day lower heating value (LHV) (EAEC 2001ee). This is a substantial rate of energy consumption and holds the potential to impact energy supplies. Under expected project conditions, electricity will be generated at a baseload (820 MW) efficiency of approximately 56 percent LHV, and additional peaking capacity (267 MW) at an incremental efficiency of 41 to 42 percent LHV, yielding a full load (1,087 MW) efficiency ranging from 51.5 percent to 52 percent LHV (EAEC 2001a, AFC Figures 2.2-4a & 2.2-4b; EAEC 2001ee; EAEC 2001hh). Compare this to the average fuel efficiency of a typical 1960s-era utility company baseload power plant at approximately 35 percent LHV.

Adverse Effects On Energy Supplies And Resources

The applicant has described its sources of supply of natural gas for the project (EAEC 2001a, AFC §§ 1.1, 1.3.2, 2.1, 2.4.3, 6.0, 10.2.1). Natural gas for the EAEC will be supplied from the existing PG&E system via PG&E's Line 401 at the Bethany compressor station, about 1.4 miles west of the EAEC site. Line 401 is capable of delivering the required quantity of gas to the EAEC. Furthermore, the PG&E gas supply infrastructure is extensive, offering access to vast reserves of gas from Canada and the Southwest. This source represents far more gas than would be required for a project this size. It is therefore highly unlikely that the project could pose a substantial increase in demand for natural gas in California.

Additional Energy Supply Requirements

Natural gas fuel will be supplied to the project by PG&E's existing line 401 via a new 20-inch diameter pipeline (EAEC 2001a, AFC §§ 1.1, 1.3.2, 2.1, 2.4.3, 6.0, 6.1, 10.2.1). This line should provide adequate access to natural gas fuel. There is no real likelihood that the EAEC will require the development of additional energy supply capacity.

Compliance With Energy Standards

No standards apply to the efficiency of the EAEC or other non-cogeneration projects.

Alternatives To Reduce Wasteful, Inefficient And Unnecessary Energy Consumption

The EAEC 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 EAEC will be configured as a combined cycle power plant, in which electricity is generated by three gas turbines, and additionally by a steam turbine that operates on heat energy recuperated from the gas turbines' exhaust (EAEC 2001a, AFC §§ 1.1, 2.2.2, 2.2.3, 2.2.4). By recovering this heat, which would otherwise be lost up the exhaust stacks, the efficiency of any combined cycle power plant is increased considerably from that of either gas turbines or steam turbines operating alone. Such a configuration is well suited to the large, steady loads met by a baseload plant, intended to supply energy efficiently for long periods of time.

Duct Burners

While duct burners are commonly employed in combined cycle power plants, the EAEC presents a new approach to the use of duct burners. As the gas turbine's hot exhaust gases flow into the HRSG through the transition duct, a nozzle arrangement injects more natural gas fuel into the gas stream. The additional fuel burns, adding heat to the gas stream. This increased heat can serve several purposes. It ensures that the steam produced for the steam turbine is sufficiently hot to provide optimum steam turbine performance; it can produce additional steam for injection into the gas turbine, increasing the gas turbine's power output; and it can produce still more steam to drive an even larger steam turbine. Another valuable feature of duct burners is their contribution to flexibility; while a modern clean-burning combined cycle operates optimally at steady (baseload) output, the duct burner allows the unit to load follow, throttling up and down in response to system load changes. In the EAEC, the duct burners will perform all these tasks.

In a common combined cycle power plant (represented by Calpine's Metcalf Energy Center project), a pair of F-class gas turbine generators produce 544 MW; the balance of the plant's 600 MW output, or 56 MW, is provided by the duct burners. Thus, about nine percent of the plant's total power output is generated by heat from the duct burners. This is the power equivalent of 1.3 General Electric LM6000 simple cycle peaker gas turbines, currently the most popular gas turbine peaking unit.

Another example of duct burning is Calpine's Delta Energy Center, in which three F-class gas turbine generators produce 816 MW of the plant's 880 MW capacity. The balance, 64 MW, is provided by heat from the duct burners; this represents seven percent of the plant's total output, or the equivalent of 1.5 GE LM6000 simple cycle peakers.

The EAEC, also a Calpine project, represents a wide departure from this norm. The unique feature of the EAEC is that the duct burners are much larger than normal. While complete data were not made available to Energy Commission staff for a thorough numerical analysis of project efficiency, the information provided by the applicant demonstrates the following. Maximum power output from the plant will be 1,087 MW (at 45°F ambient, with maximum inlet air fogging, duct burning and steam injection). Subtracting the power output of the three gas turbine generators, or 820 MW (EAEC 2001a, AFC Figures 2.2-4a and 2.2-4b; EAEC 2001e, page 10; EAEC 2001ee; EAEC 2001hh) yields 267 MW to be provided by heat from the duct burners. This represents 25 percent of total power output, or the equivalent of more than six GE LM6000 peakers.

Note the relevance of this efficiency comparison with the LM6000 simple cycle peaker. According to data provided by the applicant, while the fuel efficiency of the plant with the duct burners not operating will be 56 percent LHV (representing the state of the art), the incremental fuel efficiency of the EAEC duct burners ranges from 41.4 percent to 42.3 percent LHV. This compares closely to the typical fuel efficiency of an LM6000 at 40.2 percent LHV (GTW 2000). From a fuel efficiency standpoint, therefore, the EAEC, as proposed, represents a three-on-one combined cycle baseload power plant producing 820 MW, plus an additional 267 MW of peaking power equivalent to six LM6000 simple

cycle peakers. (Staff is concerned about plant reliability issues; see **Power Plant Reliability.**)
It should be noted that this reliance on large duct burners appears to be the beginning of a trend. Calpine has since filed AFCs for the Inland Empire Energy Center (01-AFC-17) and the Central Valley Energy Center (01-AFC-22), which both employ these burners. The chief benefits of this configuration involve capital investment; the developer can save substantial money in building the project compared to a more typical four-on-two combined cycle arrangement. Energy Commission staff fully expects Calpine's competitors to consider following this lead in their future designs.

Equipment Selection

Modern gas turbines embody the most fuel-efficient electric generating technology available today. Their higher pressure ratio and firing temperature offer higher efficiencies than conventional turbines. They offer proven technology with numerous installations and extensive run time in commercial operation. Emission levels are also proven, and guaranteed emission levels have been reduced based on operational experience and design optimization by the manufacturers. The F-class gas turbines to be employed in the EAEC represent some of the most modern and efficient such machines now available. The applicant will employ three General Electric PG7251(FB) (Frame 7FB) gas turbine generators in a three-on-one combined cycle power train (EAEC 2001a, AFC §§ 1.1, 2.2.2, 2.2.4, 2.2.4.1). This configuration is nominally rated at approximately 850 MW and 57.5 percent efficiency LHV at ISO[1] conditions (GTW 2000).

One possible alternative machine is the Alstom Power ABB KA24, a gas turbine nominally rated in a three-on-three configuration at 780 MW and 56.5 percent efficiency LHV at ISO conditions (GTW 2000).

Another alternative is the Siemens-Westinghouse 501FD (W501FD), nominally rated in three-on-one configuration at approximately 825 MW and 55.8 percent efficiency LHV at ISO conditions (GTW 2000).

Still another alternative is the General Electric GE Frame 7FA, predecessor to the Frame 7FB, nominally rated in three-on-one configuration at approximately 792 MW and 56.5 percent efficiency LHV at ISO conditions (GTW 2000). Except for slightly lower pressure ratio and firing temperature, this machine is identical to the Frame 7FB.

Any differences among the GE 7FA, ABB KA24, and W501FD in actual operating efficiency would be insignificant. The GE 7FB selected for this project, however, is measurably more efficient, by about 1.5 percentage points.

Efficiency Of Alternatives To The Project

The project objectives include competing as a merchant plant, generating energy for sale on the spot market, and directly to customers via short- and mid-term contracts (EAEC 2001a, AFC §§ 1.1, 2.2.16, 9.5, 10.2.2, 10.3).

[1] International Standards Organization standard conditions are 59°F (15°C), 60 percent relative humidity, and sea level pressure (29.92 in. Hg).

Alternative Generating Technologies

Alternative generating technologies for the EAEC are considered in the AFC (EAEC 2001a, AFC §§ 1.4, 9.5). Conventional boiler and steam turbine, simple cycle combustion turbine, conventional combined cycle, Kalina combined cycle, advanced combustion turbines, natural gas, coal, oil, solar, wind, hydroelectric, biomass, geothermal, nuclear, municipal solid waste and ocean energy conversion technologies are all considered. Given the project objectives, location and air pollution control requirements, staff agrees with the applicant that only natural gas-burning technologies are feasible.

Natural Gas-Burning Technologies

Fuel consumption is one of the most important economic factors in selecting an electric generator; fuel typically accounts for over two-thirds of the total operating costs of a fossil-fired power plant (Power 1994). Under a competitive power market system, where operating costs are critical in determining the competitiveness and profitability of a power plant, the plant owner is strongly motivated to purchase fuel-efficient machinery.

Capital cost is also important in selecting generating machinery. Recent progress in the development of large, stationary gas turbines, aided by the incorporation into these machines of technological advances made in the development of aircraft (jet) engines, has created a situation in which several large manufacturers compete vigorously to sell their machines. This, combined with the cost advantages of assembly line manufacturing, has driven down the prices of these machines. Thus, the power plant developer can purchase a turbine generator that not only offers the lowest available fuel costs, but at the same time sells for the lowest per-kilowatt capital cost.

One possible alternative to an F-class gas turbine is a G-class machine, such as the Siemens-Westinghouse 501G gas turbine generator, which employs partial steam cooling to allow slightly higher firing temperatures. This results in a combined cycle rating of 365 MW at 58.0 percent LHV at ISO conditions (GTW 2000). The 501G is still relatively new; the first such machines only recently began operation at the McIntosh plant in Florida owned by Lakeland Electric and Water, and at PG&E National Energy's Millennium plant in Charlton, Massachusetts (GTW 2001, p. 45). Given the minor efficiency improvement promised by the G-class turbine and the lack of a proven track record for the 501G, the applicant's decision to purchase F-class machines is a reasonable one.

Another possible alternative to the F-class gas turbine is an H-class machine. An example is the General Electric S107H, with rated power output of 400 MW and a claimed fuel efficiency of 60 percent LHV at ISO conditions (GTW 2000). This high efficiency is achieved through a higher pressure ratio and higher firing temperature, made possible by cooling the initial turbine stages with steam instead of air. This first Frame 7H application is not expected to enter service until the end of 2003 at Sithe Energy's Independence Station in Scriba, New York (GTW 2001, p. 28). Given the lack of proven performance, staff agrees with the applicant's decision to employ F-class machines.

Duct Burner Alternatives

Staff's concerns over reliability (see **Power Plant Reliability**) prompt consideration of a different configuration; two alternatives suggest themselves.

One alternative would be to build the EAEC as a more typical three-on-one combined cycle plant, similar to the Delta Energy Center. Of the 880 MW total output, approximately 60 MW would be provided by heat from the duct burners. Overall project efficiency would likely be nearly 56 percent, which represents the state of the art for large natural gas-fired power plants. The drawback to this alternative is the reduction in both maximum output and peaking capability.

The second alternative would be to construct the EAEC as a four-on-two combined cycle plant, similar to the La Paloma Generating Plant, with a nominal output around 1,100 MW, the same as that proposed for the EAEC. The drawbacks to this alternative are the loss of peaking capability and the increased capital cost of an additional gas turbine generator, an additional HRSG, an additional steam turbine generator, and the associated balance of plant equipment for the attendant second steam cycle.[2]

Inlet Air Cooling

A further choice of alternatives involves the selection of gas turbine inlet air cooling methods. The two commonly used techniques are the evaporative cooler or fogger, and the chiller; both devices increase power output by cooling the gas turbine inlet air. A mechanical chiller can offer greater power output than the evaporative cooler on hot, humid days, but consumes electric power to operate its refrigeration process, thus slightly reducing overall net power output and, thus, overall efficiency. An absorption chiller uses less electric power, but necessitates the use of a substantial inventory of ammonia. An evaporative cooler or a fogger boosts power output best on dry days; it uses less electric power than a mechanical chiller, possibly yielding slightly higher operating efficiency. The difference in efficiency among these techniques is relatively insignificant.

The applicant proposes to employ inlet air fogging (EAEC 2001a, AFC §§ 2.2.2, 2.2.4.1). Given the climate at the project site and the relative lack of clear superiority of one system over the other, staff agrees that the applicant's approach will yield no significant adverse energy impacts.

Condenser Cooling Technology

The EAEC is proposed with an evaporative (wet) cooling system to cool the steam turbine's condenser. In California's arid climate, wet cooling typically results in the greatest generating efficiency. In response to concerns over the prodigious consumption of water engendered by a wet cooling system, an analysis was made of an alternative cooling system, a dry cooling system incorporating an air-cooled condenser (EAEC 2001p). If such a system were incorporated into the project, overall annual fuel efficiency might be expected to drop as much as two percentage points.[3] While this is a

[2] Note that it is possible to build a four-on-one combined cycle plant; this, however, would not allay staff's reliability concerns.

[3] This is the figure estimated for the Sutter Power Project (97-AFC-2).

measurable degradation in fuel efficiency, staff believes that it could be justified by the significant savings in water consumption. From an efficiency standpoint, then, staff regards the use of dry cooling as a justifiable modification.

In conclusion, the project configuration (combined cycle) and generating equipment (F-class gas turbines) chosen appear to represent the most efficient feasible combination to satisfy the project objectives. Other than alternative arrangements that eliminate the oversized duct burners (discussed above), there are no alternatives that could significantly reduce energy consumption.

CUMULATIVE IMPACTS

There are currently two nearby power plant projects that hold the potential for cumulative energy consumption impacts when aggregated with the project. GWF Energy LLC has filed an AFC with the Energy Commission for the 169 MW Tracy Peaker Plant (01-AFC-16), and Midway Power, LLC has recently filed an AFC for the 1,120 MW Tesla Power Plant (01-AFC-21). Staff knows of no other projects that could result in cumulative energy impacts. Cumulative impacts of energy consumption could exist if the supply of natural gas fuel were jeopardized by the aggregation of these projects. Based on the robust nature of the natural gas supply infrastructure in California, and in this region, staff deems it highly unlikely that this will be the case.

Staff believes that construction and operation of the project will not bring about indirect impacts, in the form of additional fuel consumption, that would not have occurred but for the project. The older, less efficient power plants consume more natural gas to operate than the new, more efficient plants such as the EAEC. Since natural gas will be burned by the power plants that are most competitive on the spot market, the most efficient plants will run the most. Operating in baseload mode, the high efficiency of the proposed EAEC should allow it to compete very favorably, running at a high capacity factor, replacing less efficient power generating plants in the market, and therefore not impacting or even reducing the cumulative amount of natural gas consumed for power generation. Operating in peaking mode, the EAEC's fuel efficiency compares favorably to alternative peaking plants, and would therefore have no indirect impact on fuel consumption.

FACILITY CLOSURE

Closure of the facility, whether planned or unplanned, will not influence, nor will it be influenced by, project efficiency. Any efficiency impacts due to closure of the project would be on the electric system as a whole. Yet the vast size of the electric system serving California, the number of generating plants offering to sell power into it, and the existence of the California Independent System Operator to ensure the efficient management of the system, all lend assurance that closure of this facility will not produce significant adverse impacts on efficiency.

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

The project, if constructed and operated as proposed, would generate a nominal 820 MW of baseload electric power at an overall fuel efficiency around 56 percent LHV, and 267 MW of peaking power at an efficiency of around 41 to 42 percent LHV, yielding a total nominal output of 1,100 MW at an overall fuel efficiency around 51.5 to 52 percent LHV. As proposed, the EAEC will consume substantial amounts of energy at efficiency levels comparable to a typical combined cycle baseload power plant in conjunction with a typical peaking plant. However, it will not create significant adverse effects on energy supplies or resources, nor will it require additional sources of energy supply or consume energy in a wasteful or inefficient manner. Staff therefore concludes that the project would present no significant adverse impacts upon energy resources.

No energy standards apply to the project. No cumulative impacts on energy resources are likely. Facility closure would not likely present significant impacts on electric system efficiency.

RECOMMENDATION

From the standpoint of efficiency, staff believes the EAEC can be certified. No Conditions of Certification are proposed.

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POWER PLANT RELIABILITY

Steve Baker

INTRODUCTION

In this analysis, Energy Commission staff addresses the reliability issues of the project to determine if the power plant is likely to 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 is likely to be built in accordance with typical industry norms for reliability of power generation. While East Altamont Energy Center, LLC, (applicant) has predicted a 92 to 98 percent availability for the East Altamont Energy Center (EAEC) (see below), staff uses the benchmark identified above, rather than the applicant's projection, to evaluate the project's reliability.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

Presently, there are no laws, ordinances, regulations or standards (LORS) that establish either power plant reliability criteria or procedures for attaining reliable operation. However, the commission must make findings as to the manner in which the project is to be designed, sited and operated to ensure safe and reliable operation (Cal. Code Regs., tit. 20, § 1752(c)). Staff takes the approach that a project's reliability 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 (see **Setting** below).

SETTING

In the regulated monopoly electric industry of past decades, the utility companies assured overall system reliability, in part, by maintaining a "reserve margin." This amounted to having on call, at all times, sufficient generating capacity, in the form of standby power plants, to quickly handle unexpected outages of generating or transmission facilities. The utilities generally maintained a seven- to ten-percent reserve margin, meaning that sufficient capacity was on call to quickly replace from seven to ten percent of total system resources. This margin proved adequate, in part because of the reliability of the power plants that constituted the system.

Now, in the newly restructured competitive electric power industry, the responsibility for maintaining system reliability falls largely to the California Independent System Operator (CaISO), an entity that purchases, dispatches and sells electric power throughout the state. How CaISO will ensure system reliability is still being determined; protocols are being developed and put in place that will, it is anticipated, allow sufficient reliability to be maintained under the competitive market system. "Must-run" power purchase agreements and "participating generator" agreements are two mechanisms being employed to ensure an adequate supply of reliable power (Mavis 1998, pers. comm.).

The CaISO also requires those power plants selling ancillary services, as well as those holding reliability must-run contracts, to fulfill certain requirements, including:

- filing periodic reports on plant reliability;
- reporting all outages and their causes; and
- scheduling all planned maintenance outages with the CaISO (Detmers 1999, pers. comm.).

The CaISO's mechanisms to ensure adequate power plant reliability apparently have been 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 is 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 (McGraw-Hill 1994). It is possible that, if significant numbers of power plants exhibit individual reliability sufficiently lower than this historical level, the assumptions used by CaISO to ensure system reliability will prove invalid, with potentially disappointing results. On November 29, 2001, the CaISO Board of Directors determined to pursue a program to establish and enforce power plant maintenance standards (McCorkle 2001).

Until the restructured competitive electric power system has undergone a shakeout period, and the effects of varying power plant reliability are thoroughly understood and compensated for, staff deems it wise to encourage power plant owners to 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 the 1,100 MW (nominal) EAEC, selling energy and capacity to the power market and via bilateral contracts (EAEC 2001a, AFC §§ 1.1, 2.2.2, 10.2.2, 10.3). The EAEC will operate as an 820 MW baseload power plant with an additional 267 MW of peaking capacity, achieved through the use of unusually large duct burners (EAEC 2001hh) (see **Power Plant Efficiency**). The project is expected to operate at an overall availability in the range of 92 to 98 percent (EAEC 2001a, AFC §§ 2.2.2, 2.2.16, 2.4.1, 10.2.2), and at a capacity factor, over the life of the plant, of 25 to 100 percent of base load (EAEC 2001a, AFC §§ 2.4.1, 10.2.2). The applicant envisions operating at baseload up to 8,000 hours per year, and in combined baseload and peaking mode up to 5,080 hours per year (EAEC 2001a, AFC § 10.2.2).

ANALYSIS

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 subtract from its availability. Measures of power plant reliability are based on its 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. Throughout its intended 30-year life (EAEC 2001a, AFC § 10.2.2), the EAEC will be expected to perform reliably. 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 the EAEC will be as reliable as other power plants on the electric system, and will therefore not degrade system reliability.

EQUIPMENT AVAILABILITY

Equipment availability will 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 QA/QC program (EAEC 2001a, AFC § 2.4.5) typical of the power industry. Equipment will be purchased from qualified suppliers, based on technical and commercial evaluations. The project will maintain a record of documents for review and reference including vendor instruction manuals; design calculations and drawings; quality assurance reports; inspection and equipment testing; conformed construction drawings and records; procurement specifications; and purchase orders and correspondence. The project owner will 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

A generating facility called on to operate in baseload 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.

The applicant plans to provide appropriate redundancy of function for the project (EAEC 2001a, AFC § 2.4.2). The fact that the project consists of three trains of gas turbine generators/HRSGs provides inherent reliability. Failure of a non-redundant component

of one train should not cause the other trains to fail, thus allowing the plant to continue to generate (at reduced output). Further, the plant's distributed control system (DCS) will be built with typical redundancy (EAEC 2001a, AFC § 2.4.2.2). Emergency DC and AC power systems will be supplied by redundant batteries, chargers and inverters (EAEC 2001a, AFC § 2.2.5.3). Other balance of plant equipment will be provided with redundant examples (EAEC 2001a, AFC § 2.4.2; EAEC 2001hh), thus:

- Two 100 percent HRSG feed water pumps per HRSG;
- three 50 percent condensate pumps;
- two 50 percent circulating water pumps;[1]
- two 100 percent closed-cycle cooling water pumps;
- two 100 percent closed-cycle cooling water heat exchangers; and
- three 50 percent demineralized water systems with redundant installed pumps.

The applicant proposes to construct the EAEC power generation facility in a three-on-one configuration (with only one condenser and one cooling system). (For a more detailed discussion of this configuration, see **Power Plant Efficiency**.) If the steam turbine generator should fail, steam from the HRSGs can be bypassed directly to the condenser, allowing the gas turbines to continue to operate, producing up to 540 MW. However, a single failure of the condenser or the cooling system would force the entire plant to shut down, resulting in the loss of up to 1,100 MW at maximum generation. In the Potrero Power Plant Unit 7 Project (00-AFC-4), the CaISO expressed concern that the 540 MW unit could be shut down by a single condenser or cooling system failure. Energy Commission staff is pursuing discussions with the CaISO regarding its concern with similar outages of the EAEC.

In order to reduce this risk to system reliability, staff notes two possible alternatives. One is to modify the EAEC power configuration to a four-on-two train, more customary for power plants this size. This configuration would allow for two condensers and two cooling systems to be online. Two gas turbines and one steam turbine could still operate at 540 MW in the event that one of the condensers or one of the cooling systems fails. The drawbacks are increased capital cost and the forfeiture of much of the 267 MW of peaking capacity. Another alternative for reducing risk to system reliability is to reduce the plant's power output from 1,100 MW to 880 MW, more normal for a three-on-one configuration such as the previously certified Delta Energy Center (98-AFC-3). While this would not reduce the likelihood of a single condenser or cooling system failure leading to total plant shutdown, it would reduce the impact (in lost megawatts) to the electric system due to failure.

With the opportunity for continued operation in the face of equipment failure afforded by either of these modifications, staff believes that equipment redundancy would be sufficient for a project such as this.

[1] Failure of one circulating water pump will allow the plant to continue to operate at approximately 65 percent of maximum output.

Maintenance Program

The applicant proposes to establish a plant maintenance program typical of the industry (EAEC 2001a, AFC §§ 2.4.1, 2.4.5, 10.2.2). Equipment manufacturers provide maintenance recommendations with their products; the applicant will base its maintenance program on these recommendations. For example, each gas turbine will be scheduled for a week to 10 days per year off-line (at times of low electricity demand) in order to perform annual inspections and cleaning. Every third year, each gas turbine will undergo a hot gas path inspection lasting up to three weeks. Every sixth year, each gas turbine will undergo a major maintenance turnaround that typically lasts at least four weeks. **The program will encompass preventive and predictive maintenance techniques. Maintenance outages will be planned for periods of low electricity demand.** In light of these plans, staff expects that the project will be adequately maintained to ensure acceptable reliability.

FUEL AND WATER 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

The EAEC will burn natural gas from the Pacific Gas and Electric Company (PG&E) system. Gas will be transmitted to the plant, via a new 20 inch diameter pipeline connection to PG&E's Line 401 (EAEC 2001a, AFC §§ 1.1, 1.3.2, 2.1, 2.4.3, 6.0, 10.2.1). The PG&E natural gas system represents a resource of considerable capacity. This system offers access to adequate supplies of gas (EAEC 2001a, AFC § 10.2.1). Staff agrees with the applicant's prediction that there will be adequate natural gas supply and pipeline capacity to meet the project's needs.

Water Supply Reliability

The EAEC will obtain water for plant cooling and process makeup via the Byron Bethany Irrigation District (BBID) from two sources of water, surface water and recycled water. During the initial years of plant operation, raw water will be provided by BBID. The applicant states that as the community of Mountain House, a newly approved town near the project site, is developed and recycled water becomes available, recycled water will supplement raw water, resulting in the reduction in raw water use by up to 50 percent by year 2024 (EAEC 2001a, AFC §§ 1.1, 1.5.2, 2.2.7, 7.0, 8.14, 10.2.2). Domestic water will be provided by treating BBID water. For further discussion of water supply, see that portion of this document entitled **Water Resources**.

POWER PLANT RELIABILITY IN RELATION TO NATURAL HAZARDS

Natural forces can threaten the reliable operation of a power plant. High winds, tsunamis (tidal waves) and seiches (waves in inland bodies of water) will not likely represent a hazard for this project, but flooding and seismic shaking (earthquake) present credible threats to reliable operation.

Flooding

The site is essentially flat with an elevation of approximately 40 feet above mean sea level and is not within either the 100- or 500-year flood plain. The project area is protected from flooding by levees and drainage channels to the west and north (EAEC §§ 2.3.1, 8.14.1.3). Staff believes that there are no special concerns with the power plant functional reliability due to flooding events. For further discussion, see that portion of this document entitled **Water Resources**.

Seismic Shaking

The site lies within Seismic Zone 4 (EAEC 2001a, AFC § 2.3.1); see the portion of this document entitled **Geology and Paleontology**. The project will be designed and constructed to the latest appropriate LORS (EAEC 2001a, AFC § 10.4, Appendix 10B2). Compliance with current LORS applicable to seismic design represents an upgrading of performance during seismic shaking compared to older facilities, due to the fact that these LORS have been periodically and continually upgraded. By virtue of being built to the latest seismic design LORS, this project will 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 portion of this document entitled **Facility Design**. In light of the historical performance of California power plants and the electrical system in seismic events, staff believes there is no real concern that power plant reliability will affect the electric system's reliability due to seismic events.

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 Council (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 the following summary generating unit statistics for the years 1994 through 1998 (NERC 1999):

For Combined Cycle units (All MW sizes)

Availability Factor = 91.49 percent

The General Electric Frame 7F gas turbines that will be employed in the project have been on the market for several years now, and can be expected to exhibit typically high availability. While the 7FB is new, it represents a minor improvement over the 7FA, which has already proven itself in actual service. General Electric can be expected to quickly deal with any Frame 7FB reliability issues that may occur. In light of this, the applicant's prediction of an annual availability factor in the 92 to 98 percent range (EAEC 2001a, AFC §§ 2.2.2, 2.2.16) appears reasonable compared to the NERC figure for similar plants throughout North America (see above). In fact, these new, large machines can well be expected to outperform the fleet of various (mostly older and smaller) gas turbines that make up the NERC statistics. Further, since the plant will consist of three parallel gas turbine generating trains, much maintenance can be scheduled during those times of year when the full plant output is not required to meet market demand, typical of industry standard maintenance procedures. The applicant's estimate of plant availability therefore appears realistic. The stated procedures for assuring design, procurement and construction of a reliable power plant appear to be in

keeping with industry norms, with the exception of the possibility of a single failure of the condenser or the cooling system shutting down the entire 1,100 MW plant. Note that the applicant proposes to take all customary measures to maximize the reliability of these systems, including the incorporation of dual steam condensers with divided water boxes, titanium condenser tubing, and cooling tower and circulating water system designs that minimize the chances of a failure causing plant shutdown (EAEC 2001hh).

Energy Commission staff believes the EAEC may prove to be an adequately reliable plant, but questions the potential impact of failure on the electric system. Staff will reserve judgment pending discussions with CaISO.

Dry Cooling vs. Wet Cooling

The applicant proposes to employ a wet cooling system for the EAEC, and has provided an analysis of an alternative dry cooling system. The applicant described how the use of dry cooling on hot summer days reduces the cooling effect, causing a reduction of up to 46.4 MW (plant-wide) in the EAEC's power output (EAEC 2001p). This is a four percent drop in the overall power plant output. Furthermore, if temperatures rise too high, steam is no longer condensed rapidly enough, and plant output must be reduced, or the plant may have to be shut down entirely. This decreases plant availability on very hot days, when power is most needed. However, because there are only a few very hot summer days per year at the project site, the possible impacts of plant shutdown due to high temperatures would be minimal. Staff believes the electric system's reliability would not be affected significantly by the slight change in power output, or the remote possibility of plant shutdown, due to very high temperatures during hot summer days.

The use of dry cooling would reduce the plant's overall water consumption by approximately 98 percent (EAEC 2001p), limiting water usage to boiler makeup (to replenish losses resulting from blowdown and power augmentation), combustion turbine inlet air fogging, and potable and service water needs. Using wet cooling would require a vast amount of water, which in turn requires reliable water supply resources that can provide such capacity. (Water availability is addressed in the portion of this document entitled **Water Resources**.) From a reliability standpoint, staff regards the use of dry cooling as a justifiable modification.

FACILITY CLOSURE

Closure of the facility, whether planned or unplanned, cannot impact power plant reliability. Reliability impacts on the electric system from facility closure, should there be any, are dealt with in the portion of this document entitled **Transmission System Engineering**.

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

The applicant predicts an equivalent availability factor in the 92 to 98 percent range, which staff believes is achievable in light of the industry norm of 91.5 percent for this

type of plant. Staff is concerned, however, that a single failure of the condenser or the cooling system could cause the loss to the electric system of nearly 1,100 MW. While staff can conclude that the plant will be built and operated in a manner consistent with industry norms for reliable operation for a power plant of lesser generating capacity, staff questions the adequacy of reliability of the EAEC as an 1,100 MW plant. Staff notes that the EAEC could be redesigned to either an 880 MW three-on-one combined cycle configuration, or an 1,100 MW four-on-two combined cycle configuration. Until discussions have been concluded with CaISO regarding the acceptability of the potential loss to the system of so many megawatts from a single failure, staff cannot conclude that the EAEC will exhibit an acceptable level of reliability.

RECOMMENDATIONS

Further study of the project is underway; staff will withhold its recommendations until after the conclusion of discussions with CaISO.
No Conditions of Certification are proposed.

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TRANSMISSION SYSTEM ENGINEERING

Ajoy Guha and Al McCuen

INTRODUCTION

The Transmission System Engineering (TSE) analysis provides the basis for the findings in the Energy Commission's decision. This staff assessment indicates whether or not the transmission facilities associated with the proposed project conform to all applicable laws, ordinances, regulations and standards (LORS) required for safe and reliable electric power transmission.

Under the California Environmental Quality Act (CEQA), the Energy Commission must conduct an environmental review of the "whole of the project," which may include facilities not licensed by the Energy Commission (California Code of Regulations, title 14, §15378). Therefore, the Energy Commission must identify and evaluate the environmental effect of construction and operation of any new or modified transmission facilities required for the project's interconnection to the electric grid and also beyond the project's interconnection with the existing transmission system that are required as a result of the power plant addition to the California transmission system. This staff assessment indicates whether or not the applicant has accurately identified all transmission facilities.

Calpine, DBA East Altamont Energy Center, LLC (applicant) filed an Application for Certification to the California Energy Commission to construct a nominal 1,100 megawatt (MW) natural gas-fired combined cycle generating facility to be located in northeastern Alameda county. The applicant proposes to connect their project, East Altamont Energy Center (EAEC), to the existing Tracy-Westley 230 kV transmission line of the Western Area Power Administration (Western) system (EAEC 2001a, AFC pages 1-1, 5-1). Unlike other applications for certification, since the Western system is not a part of the California Independent System Operator (Cal-ISO) grid, the Cal-ISO is not directly responsible for ensuring electric system reliability for the generator interconnection and does not provide analysis and testimony in the Commission's process. The staff therefore has increased responsibility to evaluate the system reliability impacts of the project and provide conclusions and recommendations to the Commission.

Staff's analysis evaluates the power plant switchyard, outlet line, termination and downstream facilities identified by the applicant. Staff's analysis provides proposed conditions of certification to ensure the project complies with applicable LORS during the design review, construction, operation and potential closure of the project.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

- 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 and operation or use of overhead electric lines and to the public in general.

- The National Electric Safety Code, 1999 provides electrical, mechanical, civil and structural requirements for overhead electric line construction and operation.
- Western Systems Coordinating Council (WSCC) Reliability Criteria provides 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 WSCC Reliability Criteria includes the Reliability Criteria for Transmission System Planning, Power Supply Design Criteria, and Minimum Operating Reliability Criteria. Analysis of the WSCC system is based to a large degree on WSCC 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, loading and loss of load that may occur on systems during various disturbances. Performance levels range from no significant adverse effects inside and outside a system area during a minor disturbance (loss of load or a single transmission element out of service) to that seeks to prevent system cascading and the subsequent blackout of islanded areas during a major disturbance (such as loss of multiple 500 kV lines in a right of way and/or multiple generators). While controlled loss of generation, load, or system separation is permitted in certain circumstances, their uncontrolled loss is not permitted (WSCC 2000).
- North American Electric Reliability Council (NERC) Planning Standards provides policies, standards, principles and guidelines 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 WSCC’s 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).
- Cal-ISO Reliability Criteria also provide policies, standards, principles and guidelines 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 WSCC's Criteria for Transmission System Contingency Performance and the NERC Planning Standards. The Cal-ISO Reliability Criteria incorporate the WSCC Criteria and NERC Planning Standards. However, the Cal-ISO Reliability Criteria also provide some additional requirements that are not found in the WSCC Criteria or the NERC Planning Standards. The Cal-ISO Reliability Criteria apply to all existing and proposed facilities interconnecting to the Cal-ISO controlled grid. It also applies when there are any impacts to the Cal-ISO grid due to facilities interconnecting to adjacent controlled grids not operated by the Cal-ISO.

SETTING

The existing bulk transmission facilities in the vicinity of the EAEC project area include:

- Western's Tracy 500/230 kV Substation
- Tracy - Westley 230 kV transmission line
- Tracy - Olinda 500 kV transmission line
- Tracy – Tesla 500 kV transmission line
- Tracy – Los Banos 500 kV transmission line
- Tracy – Hurley 230 kV transmission lines #1 & 2
- Tracy – Tesla 230 kV transmission lines #1 & 2
- Tracy – LLNL 230 kV transmission line
- Tesla – Vaca Dixon 500 kV transmission line
- Tesla – Table Mountain 500 kV transmission line.

The Tracy Substation receives significant power from the California Oregon Transmission project which is part of the Path 66 500 kilovolt (kV) lines that form the California Oregon Interties (COI). These lines carry California hydro generation and imports from the Pacific Northwest. The Tracy substation is also connected to the Los Banos-Gateway-Midway Path 15 transmission system. Two 230 kV lines from the Tracy substation are connected to the Sacramento Municipal Utility District (SMUD) system. Additional 230 kV lines are connected to the Pacific Gas & Electric (PG&E), Modesto Irrigation District (MID) and Turlock Irrigation District (TID) systems. The EAEC project will potentially decrease the 500 kV line flows and increase the 230 kV line flows. The 230 kV line flow increases have the potential to cause transmission "congestion" and reliability criteria violations in the area.

PROJECT DESCRIPTION

SWITCHYARD AND INTERCONNECTION FACILITIES

The EAEC site will be located at the northeastern edge of Alameda County, about 8 miles northwest from the city of Tracy, California and about 0.4 miles east of Western's existing Tracy Substation. The EAEC will consist of three combustion turbine generators (each 198.9 MW gross capacity) and one steam turbine generator (569.5 MW gross capacity), for a total nominal output of 1100 MW. Each generating unit will be connected to a 18/230 kV step-up transformer and the high voltage terminals of the transformers will be connected to the new EAEC 230 kV switchyard by overhead conductors. The EAEC 230 kV switchyard will be configured with a 3000 ampere main and a 3000 ampere transfer bus. The switchyard will have four switch bays, each with a breaker and a half arrangement, for a total of twelve air-insulated 230 kV circuit breakers and each breaker will be designed for 63 kiloampere (kA) interrupting capacity. The EAEC switchyard will be connected to the existing Western grid by looping the existing Tracy-Westley circuit lines (Jointly owned by the MID and TID. It is operating now as a single line, but will be split into two lines) through the EAEC switchyard and terminating the lines on two 2000 ampere separate breakers at Tracy and Westley substation ends. In order to connect the EAEC switchyard to the existing Tracy-Westley 230 kV double circuit lines, about 0.5 mile of two new double circuit transmission lines on separate steel tubular pole structures will be built on the south side of the EAEC switchyard. As a result, there will be two Tracy-EAEC 230 kV lines and also two EAEC-Westley 230 kV lines (EAEC 2001a, AFC pages 5-1 to 5-6, figures 5.1-2, 5.2-1 to 5.2-5,

5.5-1 to 5.5-3). This configuration for the interconnection and switchyard is in accordance with good utility practices and is considered acceptable. The EAEC switchyard work will be done within the fenced yard of the EAEC plant. The preferred route for the new interconnection transmission lines will extend from the EAEC plant to Kelso Road.

ANALYSIS AND IMPACTS

SYSTEM RELIABILITY

A System Impact Study (SIS) for connecting a new power plant to the existing power system grid is performed to determine the alternate and preferred interconnection facilities to the grid, downstream transmission system impacts and their mitigation measures in conformance with system performance levels as required in Utility reliability criteria, NERC planning standards, WSCC reliability criteria and Cal-ISO reliability criteria. The study determines both positive and negative impacts, and for the reliability criteria violation cases (for the negative impacts) determines the alternate and preferred additional transmission facilities or other mitigation measures. The study is conducted with and without the new generation project and its interconnection facilities by using the computer model base case for the year the generator project will come on-line. The study normally includes a Load Flow study, Transient Stability study, Post-transient Load Flow study and Short Circuit study. The study is focused on thermal overloads, voltage deviations, system stability (excessive oscillations in generators and transmission system, voltage collapse, loss of loads or cascading outages) and short circuit duties. The study must be conducted under the normal condition (N-0) of the system and also for all credible contingency/emergency conditions, which includes the loss of a single system element (N-1) such as a transmission line, transformer or a generator and the simultaneous loss of two system elements (N-2), such as two transmission lines or a transmission line and a generator. In addition to the above analysis, the studies may be performed to verify whether sufficient active or reactive power are available in the area system or area sub-system to which the new generator project will be interconnected. The SIS is followed by supplemental studies by the participating transmission owner with details provided in a Detailed Interconnection Facility Study (DIFS) or a Facility Cost Report (FCR).

Any new transmission facilities such as a power plant switchyard, the outlet line, and downstream facilities required for connecting a project to the grid are considered part of the project and are subject to the full Application for Certification review process.

Scope of System Impact Study (SIS)

The study plan submitted by Western required two different system conditions to be addressed, 2005 heavy summer case and 2005 heavy spring case (EAEC 2001e, Data Adequacy Response Set 1, Attachment TSE-1, page 1, Appendix I). Western, the transmission owner on behalf of the applicant, has submitted so far an incomplete SIS report. The 2005 spring case load flow study results and the additional study results, plots, data/reports in appropriate format for the 2005 heavy summer case study requested by staff have not been received. The applicant has submitted an incomplete load flow study report for the 2005 heavy summer case with a list of N-1 contingencies for the Western and SMUD, MID & TID areas, PG&E category B & C contingencies and

selected load flow diagrams. Further the applicant has submitted post transient voltage study results with the contingency list of 500 kV line outages for the 2005 heavy summer case. The applicant and PG&E have also submitted transient stability and short circuit study results for the 2005 heavy summer case (EAEC 2001e, Data Response Set 1, Attachments TSE-1, Appendices II & III, PG&E SIS). Staff requested additional study results, plots, data and/or reports (CEC 2001a, Data Requests) in appropriate format for the 2005 heavy summer load flow, transient stability and short circuit studies. Staff has also requested a 2005 heavy spring load flow study and results in appropriate format for normal and credible emergency conditions of the network. Because these study results are not available,[1] the study results as stated below are only partial. The study results will finally be assessed by staff on receipt of the completed study reports as recommended.

Power Flow Study Results

Based on current study results, the SIS indicates some adverse impacts on the electrical grid due to interconnection of the EAEC as proposed. The results indicate there are overload criteria violations under both normal (N-0) and contingency (N-1 & N-2) conditions.

Normal (N-0) Conditions

Under normal conditions of the network with all facilities in service in the 2005 heavy summer case scenario, about ten potential overloaded transmission lines, per Attachment A, were found and thus violating reliability criteria. Staff requested the applicant to identify mitigation measures to offset the overload violations. These have not been received.

Contingency (N-1 & N-2) Conditions

Under single (N-1) contingency conditions, several lines in the PG&E, SMUD and Western grids, per Attachments B, were found potentially overloaded and thus violating reliability criteria. Staff asked the applicant to identify mitigation measures to offset the violations. These have not been received.

Staff also requested the applicant to provide power flow study results with some additional single contingency runs for lines in the bulk transmission system surrounding Tracy substation, in a single table format, with and without EAEC generation. These have not been received.

The existing 230 kV line between Tracy and Westley substations, owned by the MID & TID, was built as a double circuit line on the same transmission structures and is now operating as a single line. The current study finds that with interconnection of the EAEC plant as proposed, under about eight single (N-1) contingency conditions in the Western and SMUD areas, and under about nine double contingency (N-2) conditions in the PG&E area, the Tracy-Westley 230 kV line would be loaded up to 122 percent of its emergency rating with the present single line configuration. Staff, therefore, concurs

[1] Staff understands that Western has provided these studies to the Applicant but the Applicant has yet to provide them to the staff. Additionally, a Detailed Facility Interconnection Study has also been provided by Western to the Applicant. The Applicant, however, has not yet provided this to staff. This Detailed Study may resolve some of staff's concerns regarding the incomplete SIS and identify appropriate mitigation measures for criteria violations.

that to accommodate the EAEC project it will be essential to split the double circuit line into two separate lines by terminating the lines on separate breakers at both ends. As a result, since the lines will loop in and out of the EAEC switchyard, there will be two Tracy-EAEC and two EAEC-Westley 230 kV lines with a normal capacity of 650 megavolt ampere (MVA) for each line. Staff concurs that such arrangement of splitting the Tracy-Westley 230 kV line will resolve the system impact concerns expressed by MID (MID 2001a, Comments regarding EAEC's interconnection to the Tracy-Westley 230 kV line, Dated July 23, 2001).

With outage of the 230 kV east bus section of the Tracy substation, and the connected 230 kV lines and transformers, several lines in the PG&E area, per Attachment C, were found potentially overloaded, violating reliability criteria. Similarly, with outage of the 230 kV west bus section of the Tracy substation, and the connected 230 kV lines and transformers, potential overload criteria violations were found in several lines, per Attachment D, in the PG&E and SMUD areas. Staff requested the applicant to identify mitigation measures to offset the violations, but the applicant has not done so.

Although Western performed a power flow study under PG&E category C (N-2) conditions, staff could not evaluate the study results because the related overload violations results have not been provided by the applicant in a single table format, with and without the EAEC plant, as requested.

For 500 kV line contingencies (N-1 & N-2), western performed post transient voltage deviation studies and the results submitted include voltage deviations. Staff, therefore, requested the power flow study results for overload violations with the same 500 kV line contingency runs, in a single table format, with and without the EAEC plant. These have not been received.

The staff also requested the applicant to provide power flow study results with some additional double (N-2) contingency runs for lines in the bulk transmission system surrounding Tracy substation, in a single table format, with and without the EAEC generation. These also have not been received.

Transient Stability Study Results

Dynamic stability studies were conducted by PG&E using the 2005 heavy summer case to determine if the EAEC would create any adverse impact on the stable operation of the transmission grid following selected Cal-ISO category B (N-1) & C (N-2) outages (EAEC 2001e, Data Adequacy Response set 1, Attachment TSE-1, PG&E SIS pages 1-5, Appendices A & B). The results indicate there are no transient stability concerns on the transmission system following the selected disturbances for integration of the EAEC project.

Staff requested additional dynamic simulations for the 2005 heavy summer case following selected three N-1 and five N-2 line outages in the bulk transmission system near the Tracy substation (CEC 2001a, Data Requests). The results of the additional dynamic stability runs were provided by the applicant in the form of plots where vertical scales were not given. In order to assess the degree of deviations of the different electrical quantities with respect to reliability criteria, staff requested the applicant to resubmit the plots with vertical scales. These have not yet been received.

Short Circuit Study Results

The short circuit study performed by PG&E evaluated the impact of the EAEC project on the fault duties within PG&E facilities (EAEC 2001e, Data Adequacy Response Set #1, Attachment TSE-1, PG&E SIS Page 7). The study indicates that 230 kV breakers at the Tesla substation are currently subject to overstress even without the integration of the EAEC project. PG&E has existing plans to upgrade these breakers to 63 kA interrupting capacity. With addition of the EAEC project, the fault duties at Tesla 230 kV buses may exceed 63 kA by about 3.8 percent. Unless the overstressing exceeds 10 percent, PG&E guidelines do not require any upgrading of breakers or mitigation measures, and staff considers it acceptable.

The short circuit study performed by Western (EAEC 2001e, Data Adequacy Response set1, Attachment TSE-1 page 9), evaluated the impact of the EAEC project on the fault duties within the Western, SMUD, MID & TID facilities. Since the study results were submitted without listing the interrupting ratings of the circuit breakers at different substations as recommended by staff (CEC 2001a, Data Requests), staff could not evaluate whether the breakers in substations adjacent to the EAEC project, where applicable, would be adequate or would be sized to withstand the increased fault current due to the integration of the EAEC project and to protect the equipment.

NEW TRANSMISSION LINE

Besides the interconnection facilities and switchyard as proposed by the applicant (discussed above), no other new transmission facility has been identified so far. With completion of the SIS as requested, staff will be able to ensure whether any other new or modified transmission facilities will be required or not.

Downstream Impacts

The project impacts on the transmission system downstream of the interconnection facilities are discussed in the System Reliability section. Based on the limited load flow study submitted by the applicant so far, staff concurs that in order to maintain system reliability, the impacts of the EAEC project on the Western grid require that the existing Tracy-Westley 230 kV double circuit line, now operating as a single line, be split into two separate transmission lines and that the lines be terminated on two separate breakers at both ends (EAEC 2001e, Data Adequacy Response set 1, Attachment TSE-1, Pages 1, 5-7). Under normal (N-0) and contingency (N-1) conditions of the transmission grid, overload criteria violations in some of the PG&E, SMUD and Western lines have been detected and the applicant has been requested to identify mitigation measures. With more appropriate and complete SIS including the bulk 230 kV and 500 kV transmission systems surrounding the Western's Tracy substation and including 2005 heavy spring case load flow study as recommended by staff (CEC 2001a, Data Requests), the downstream impacts of the EAEC project will be more profound. Staff will then be able to assess if any more new or modified facilities, or any mitigation measures like transmission congestion management will be required to conform with applicable reliability criteria.

The short circuit study performed by PG&E evaluated the impact of the EAEC project on the fault duties within PG&E facilities (EAEC 2001e, Data Adequacy Response set 1, Attachment TSE-1, PG&E SIS page 7). The study indicates that 230 kV breakers at the

Tesla substation are currently subject to overstress even without the integration of the EAEC project. PG&E has plans to upgrade these breakers to 63 kA interrupting capacity. With the addition of the EAEC project, the fault duties at Tesla 230 kV buses may exceed 63 kA by about 3.8 percent. Unless the overstressing exceeds 10 percent, PG&E guidelines do not require any upgrading of breakers or mitigation measures, and staff considers it acceptable.

The short circuit study performed by Western (EAEC 2001e, Data Adequacy Response set1, Attachment TSE-1 page 9), evaluated the impact of the EAEC project on the fault duties within the Western, SMUD, MID & TID facilities. Since the study results were submitted without listing the interrupting ratings of the circuit breakers at different substations as recommended by staff (CEC 2001a, Data Requests), staff could not evaluate whether the breakers in substations adjacent to the EAEC project, where applicable, would be adequate or would be sized to withstand the increased fault current due to the integration of the EAEC project and to protect the equipment.

CUMULATIVE IMPACTS

Additional projects proposed in the area (such as Rio Linda/Elverta Power Project, Colusa Power Plant Project, Roseville Energy Facility, Tesla Power Project and the Consumnes Power Plant) have recently started the Commission's siting process. From the preliminary investigation staff expects that EAEC may have some cumulative impacts with respect to overloading a few transmission lines in the PG&E, SMUD and Western systems. Upon receipt of the modifications to the System Impact Study for the EAEC project and during evaluation of the pending projects mentioned herein, staff will be able to assess the cumulative impacts of this project. Should additional information regarding the overall cumulative impacts of the projects listed above be needed, that information would be the responsibility of the above projects and not the EAEC.

ALTERNATIVE TRANSMISSION LINE ROUTES

Four Transmission interconnection alternatives (EAEC 2001a, AFC Section 5.3 Pages 5-6 to 5-9) were considered by the applicant as follows:

1. A double circuit 230 kV overhead transmission line from the EAEC 230 kV switchyard to the Tracy 230 kV substation bus with modifications.

2. Two new double circuit overhead transmission lines from the 230 kV EAEC switchyard to loop the existing two single circuit Tracy-Hurley 230 kV lines through the EAEC switchyard.

3. Two new double circuit overhead transmission lines from the 230 kV EAEC switchyard, one to loop into the Tracy-Westley 230 kV line and the other to loop into the eastern circuit of the Tracy-Tesla 230 kV double circuit line.

4. A new double circuit 500kV line from the EAEC 500 kV switchyard to interconnect with the existing Tracy-Tesla and Tracy-Los Banos 500 kV lines, or to the existing Tracy-Olinda 500 kV line.

These interconnection alternatives, when compared to the preferred one (looping the Tracy-Westley 230 kV double circuit line through the EAEC 230 kV switchyard and splitting it into two lines with one additional breaker arrangement at Tracy and Westley 230 kV substations) were not chosen by the applicant on the basis of environmental impacts, engineering feasibility, reliability, longer routes, right-of-way issues, increased costs, contractual issues and visual concerns. The preferred alternative is acceptable to the staff.

COMPLIANCE WITH LORS

Since the SIS report and filings are incomplete, the staff is unable to evaluate and identify all the downstream transmission facilities and/or mitigation measures which may be required for reliable operation of the electrical transmission system after interconnection of the EAEC project. As such, compliance with applicable LORS remains indeterminate at this stage.

FACILITY CLOSURE

The parallel operation of generating stations is controlled, in part by CPUC Rule 21, which provides for contractual provisions, which may be developed, to provide backup or other power service during extended periods of non-operation and codify procedures to be followed during parallel operation. Procedures for planned, unexpected temporary closure and unexpected permanent closure must be developed or verified to facilitate effective communication and coordination between the generating station owner, transmission owner and the Cal-ISO to ensure safety and system reliability.

CPUC General Order 95, Rule 31.6 requires that "lines or portions of lines permanently abandoned shall be removed by their owners so that such lines shall not become a public nuisance or a hazard to life or property." Condition of certification **TSE-5a** requires compliance with this rule.

The ability of the above LORS to reasonably assure safe and reliable conditions in the event of facility closure was evaluated for three scenarios: Planned Closure, Unexpected Temporary Closure, and Unexpected Permanent Closure. Planned Closure occurs in a planned and orderly manner such as at the end of its useful economic or mechanical life or due to gradual obsolescence. Under such circumstances the requirement for the owner to provide a closure plan 12 months prior to closure in conjunction with applicable LORS is considered sufficient to provide adequately for safety and reliability. For instance, a planned closure provides time for the owner to coordinate with the transmission owner[2] to assure (as one example) that the owner's system will not be closed into the outlet thus energizing the power plant switchyard. Alternatively, the owner may coordinate with the transmission owner to maintain some power service via the outlet line to supply critical station service equipment or other loads[3] .

[2] The transmission owner in this instance is Western e.g., the system owner to which the project is interconnected.

[3] These are mere examples; many more exist.

Unexpected temporary closure occurs when the facility is closed suddenly and/or unexpectedly for a short term due to unforeseen circumstances such as a natural or other disaster or emergency. During such a closure the facility cannot insert power into the utility system. Closures of this sort can be accommodated by establishment of an on-site contingency plan (see General Conditions Including Compliance Monitoring and Closure Plan). Unexpected Temporary Closure occurs when the project owner closes the facility suddenly and/or unexpectedly, or abandons the facility on a permanent basis. This includes unexpected closure where the owner remains accountable for implementing the on-site contingency plan. It can also include unexpected closure where the project owner is unable to implement the contingency plan, and the project is essentially abandoned. An on-site contingency plan that is in place and approved by the CPM prior to the beginning of commercial operation of the facilities will be developed to assure safety and reliability (see General Conditions Including Compliance Monitoring and Closure Plan).

RESPONSE TO AGENCY AND PUBLIC COMMENTS

MID submitted comments (MID 2001a) to staff regarding the EAEC project interconnection to the Tracy-Westley 230 kV line (line owned by MID & TID and the electrical grid operated by Western). MID has three concerns. The first concern is for any adverse reliability impact in the Tracy-Westley line due to the EAEC project interconnection, and the others are for cost sharing of the relevant transmission project and future ownership of the proposed Tracy-EAEC 230 kV lines along with the proposed interconnection transmission facilities. Staff believes that splitting the Tracy-Westley 230 kV existing double circuit line, now operating as a single line, into two separate lines by terminating the lines on separate breakers at both ends and looping both the lines in and out of the proposed EAEC switchyard will be essential for the EAEC project interconnection, and such transmission arrangement will resolve the system impact concern expressed by MID. With respect to MID concerns regarding the project cost sharing and future ownership of the proposed Tracy-EAEC segment of the transmission lines and the proposed interconnection transmission lines, staff concludes that the applicant will have to coordinate the matter with the concerned parties.

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

Staff concludes as follows:

a) The EAEC switchyard and interconnection facilities to the Western grid, by looping the Tracy-Westley 230 kV line through the EAEC switchyard, will be adequate and reliable. To accommodate interconnection of the EAEC project and to offset downstream adverse impacts on the transmission system, it will be essential to split the exiting Tracy-Westley 230 kV double circuit line, now operating as a single line, into two separate lines by terminating the lines on separate breakers at both ends. This arrangement will also resolve the system impact concerns of MID.

b) The power plant switchyard, outlet lines, and terminations are in accordance with good utility practices and are acceptable. With implementation of the conditions of certifications recommended by staff, these facilities will comply with LORS.

c) The System Impact Study analyses, reports and filings are incomplete. According to current study results staff concludes that the EAEC project has some negative impacts on the transmission system. As outlined in the power flow study results, several transmission elements potentially exceed ratings beyond reliability criteria with the interconnection of the EAEC project under normal and contingency conditions of the system. These transmission elements require mitigation measures which have not been identified.

d) Since the SIS reports and filings are incomplete, staff is unable to fully evaluate downstream impacts, transmission facilities and/or mitigation measures required for reliable operation of the electrical transmission system. Therefore, staff concludes at this stage that compliance with applicable system reliability LORS remains indeterminate.

RECOMMENDATIONS

Staff cannot recommend that the Commission approve this project until complete system impact analyses and reports are provided, and staff and other stakeholders have sufficient opportunity to review such studies. Staff will continue to work with the applicant, Western, SMUD, and PG&E to identify impacts and resolve issues related to system reliability and conformance with LORS.

Pending receipt of additional reliability studies, staff provides the following preliminary Conditions of Certification:

PROPOSED CONDITIONS OF CERTIFICATION

TSE-1 The project owner shall furnish to the Compliance Project Manager (CPM) and to the Chief Building Official (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.

Verification: 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 rough grading, 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.

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

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TSE-2 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. [California Business and Professions Code, section 6704 et seq., and sections 6730 and 6736 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 the 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.

Verifications: 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.

TSE-3 The project owner shall keep the CBO informed regarding the status of engineering design and construction. If any discrepancy in design and/or construction is discovered, the project owner shall document the discrepancy and recommend the corrective action required. The discrepancy documentation shall become a controlled document and shall be submitted to the CBO for review and approval. The discrepancy documentation shall reference this condition of certification.

Verification: The project owner shall submit monthly construction progress reports to the CBO and CPM to be included in response to **TSE-3**. The project owner shall transmit a copy of the CBO's approval or disapproval of any corrective action taken to resolve a discrepancy to the CPM within 15 days. If 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.

TSE-4 For the power plant switchyard, outlet line and termination, the project owner shall not begin any increment of the 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 Monthly Compliance Report:

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 the 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 compliance with the applicable LORS, and shall 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 substitution of CPM and CBO approved "equivalent" equipment and an equivalent substation configuration is acceptable. The project owner shall submit the required number of copies of the design drawings and calculations as determined by the CBO.

a) The power plant switchyard and 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, Articles 35, 36 and 37 of the "High Voltage Electric Safety Orders", National Electric Code (NEC) and related industry standards.
b) Breakers and buses in the power plant switchyard and other switchyards, where applicable, shall be sized to comply with a short-circuit analysis.
c) 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.
d) Termination facilities shall comply with applicable Western interconnection standards.
e) The project conductors shall be sized to accommodate the full output from the project.
f) The existing Tracy-Westley 230 kV double circuit line shall be split into two lines and terminated on two separate breakers at the Tracy and Westley substations with interconnection of the EAEC plant to the line.
g) The project owner shall provide:
    i) The final Detailed Interconnection Facility Study (DIFS) including a description of facility upgrades, operational mitigation measures, and/or Remedial Action Scheme (RAS) sequencing and timing if applicable,
    ii) Executed Facility Interconnection Agreement,
    iii) Verification of Cal-ISO Notice of Synchronization.

Verification: At least 60 days prior to the start of rough grading of transmission facilities, 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, CPUC Rule 21, 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"[4] 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, CPUC Rule 21, 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

[4] Worst case conditions for the foundations would include for instance, a dead-end or angle pole.

description of equipment and the configurations covered by requirements **TSE-5** a) through g) above.

d) The Facilities Study and a signed letter from the applicant stating that mitigation is acceptable shall be provided concurrently to the CPM and CBO. Substitution of equipment and substation configurations shall be identified and justified by the project owner for CBO approval.

TSE-6 The project owner shall inform the CPM and CBO of any impending changes that may not conform to the requirements **TSE-5** a) through g), 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 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 that may not conform to requirements of **TSE-5** and request approval to implement such changes.

TSE-7 The applicant shall provide the following Notice to the California Independent System Operator (Cal-ISO) prior to synchronizing the facility with the California Transmission system:

1. At least one (1) week prior to synchronizing the facility with the grid for testing, provide the Cal-ISO a letter stating the proposed date of synchronization; and
2. At least one (1) business day prior to synchronizing the facility with the grid for testing, provide telephone notification to the ISO Outage Coordination Department, Monday through Friday, between the hours of 0700 to 1530 at (916)-351-2300.

Verification: The applicant shall provide copies of the Cal-ISO letter to the CPM when it is sent to the Cal-ISO one (1) week prior to initial synchronization with the grid. A report of conversation with the Cal-ISO shall be provided electronically to the CPM one (1) 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, California Code of Regulations, 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", CPUC GO-21, and applicable interconnection standards, NEC, related industry standards. These submittals 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 mechanical, structural, and civil portion of the transmission facilities shall be maintained at the power plant and made available, upon request, 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

Cal-ISO (California Independent System Operator). 1998a. Cal-ISO Tariff Scheduling Protocol posted April 1998, Amendments 1,4,5,6, and 7 incorporated.

Cal-ISO (California Independent System Operator). 1998b. Cal-ISO Dispatch Protocol posted April 1998.

CEC (California Energy Commission) 2001a, First Set of Data Requests. Dated and docketed May 10, 2001.

NERC (North American Electric Reliability Council) 1998. NERC Planning Standards, September 1997.

EAEC (East Altamont Energy Center, LLC) 2001a. Application for Certification, Volume 1 & Appendices, East Altamont Energy Center (01-AFC-4). Dated March 20, 2001. Submitted to the California Energy Commission, March 29, 2001.

EAEC (East Altamont Energy Center, LLC) 2001e, Application for Certification, Data Adequecy Response set 1, East Altamont Energy Center (01-AFC-4), Attachment TSE-1 & PG&E SIS. Dated April 18, 2001. Submitted to the California Energy Commission, May 1, 2001.

MID (Modesto Irrigation District) 2001a, Comments regarding EAEC's interconnection to the Tracy-Westley 230 kV line. Dated July 23, 2001 and submitted to the California Energy Commission on July 24, 2001.

WSCC (Western Systems Coordinating Council) 2000. Reliability Criteria, December 2000.

DEFINITION OF TERMS

ACSR — Aluminum cable steel reinforced.

AASS — Aluminum cable steel supported.
AAC — All 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.

Kiloampere (kA) — 1,000 Amperes

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. 1,000 Volts.

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 Megavolt 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 inductive loads like 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.

TRV Transient Recovery Voltage

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.

Attachment A

Overloaded lines/transformers under N-0 condition requiring identification of mitigation measures

From	To	From kV	To kV	Ckt #	Overload in % of Rating W/ EAEC 2005 HS Case	Overload in % of Rating W/O EAEC 2005 HS Case	Delta
HURLEY S	PROCTER	230	230	1	121	117.2	3.8
HEDGE	PROCTER	230	230	1	169.2	165.6	3.6
HURLEY W	HURLEY S	230	230	1	113.7	110.5	3.2
BRGHTN M	BRIGHTN	230	115	2	190.4	188	2.4
PITSBURG	TASSAJAR	230	230	1	103.1	101.1	2
C.COSTA	LS PSTAS	230	230	1	102.4	100.4	2
BRGHTN M	BRIGHTN	230	115	1	218.2	216.9	1.3
CHICO B	CHICOTP1	115	115	1	175.7	174.5	1.2
NEWCALT	FLINT	115	115	1	123.8	122.8	1
HORSHALT	NEWCALT	115	115	1	123.7	122.7	1

ATTACHMENT B

Overloaded lines/transformers under N-1 conditions requiring identification of mitigation measures

From	kV	To	kV	Ckt. No.
Pittsburg	230	San Mateo	230	1
Brightn	115	Brightn M	230	1
DPWT_TP2	115	Brightn	115	1
Morgan J2	115	GRN VLY2	115	1
Pitsburg	230	East Shore	230	1
Tassajar	230	Pittsburg	230	1
Rio OsoTB	115	Rio Oso	115	1
Chico B	115	ChicoTP1	115	1
Tracy JC	115	Ells GTY	115	1
Capehorn	60	Rollins	60	1
Procter	230	Hedge	230	1
Hurley s	230	Procter	230	1
Hurley s	230	Hurley w	230	1
Hurley s	230	Carmical	230	1
Hurley s	230	Elvertas	230	1
Hurley s	230	Hurley	115	1
Elvertas	115	North City	115	1
Nortoma	230	Elverta	230	1
Palermo	230	Palermo	115	1

Attachment C

Overloaded lines/transformers due to Tracy Sub 230 kV East bus section outage requiring identification of mitigation measures

From	To	kV	Loading in % of Rating W/O EAEC	Loading in % of Rating W/ EAEC	Delta (w-wo)
LOSBANOS	LOS BANS	230/70	122.1	127.4	5.3
BRGHTN M	BRIGHTN	230/115	192.4	195.6	3.2
PNCHE 2M	PANOCHE	230/115	137.7	139.8	2.1
PANOCHE	PNCHE 2M	230	138.9	140.9	2
BRGHTN M	BRIGHTN	230/115	220.7	222.3	1.6

Attachment D

Overloaded lines/transformers due to Tracy Sub 230 kV west bus section outage requiring identification of mitigation measures

From	To	kV	Ckt	PCT Rate W/O EAEC	PCT Rate W/EAEC	Delta (w-wo)
LOSBANOS	LOS BANS	230/70	1	124	126.9	2.9
PITSBURG	TASSAJAR	230	1	100.3	102.5	2.2
HEDGE	PROCTER	230	1	114.7	116.6	1.9
CAPEHORN	ROLLINS	60	1	113.8	115.4	1.6
PNCHE 2M	PANOCHE	230/115	2	138.1	139.7	1.6
PANOCHE	PNCHE 2M	230	2	139.3	140.8	1.5
DRUM	BONNIE N	60	1	127	128.5	1.5
CAPEHORN	BONNIE N	60	1	121.1	122.6	1.5
ELLS GTY	TRACY JC	115	1	126.8	127.9	1.1
CHICO B	CHICOTP1	115	1	175.1	176.1	1

Attachment A

Overloaded lines/transformers under N-0 condition requiring identification of mitigation measures

From	To	From kV	To kV	Ckt #	Overload in % of Rating W/ EAEC 2005 HS Case	Overload in % of Rating W/O EAEC 2005 HS Case	Delta
HURLEY S	PROCTER	230	230	1	121	117.2	3.8
HEDGE	PROCTER	230	230	1	169.2	165.6	3.6
HURLEY W	HURLEY S	230	230	1	113.7	110.5	3.2
BRGHTN M	BRIGHTN	230	115	2	190.4	188	2.4
PITSBURG	TASSAJAR	230	230	1	103.1	101.1	2
C.COSTA	LS PSTAS	230	230	1	102.4	100.4	2
BRGHTN M	BRIGHTN	230	115	1	218.2	216.9	1.3
CHICO B	CHICOTP1	115	115	1	175.7	174.5	1.2
NEWCALT	FLINT	115	115	1	123.8	122.8	1
HORSHALT	NEWCALT	115	115	1	123.7	122.7	1

Attachment B

Overloaded lines/transformers under N-1 conditions requiring identification of mitigation measures

From	kV	To	kV	Ckt. No.
Pittsburg	230	San Mateo	230	1
Brightn	115	Brightn M	230	1
DPWT_TP2	115	Brightn	115	1
Morgan J2	115	GRN VLY2	115	1
Pitsburg	230	East Shore	230	1
Tassajar	230	Pittsburg	230	1
Rio OsoTB	115	Rio Oso	115	1
Chico B	115	ChicoTP1	115	1
Tracy JC	115	Ells GTY	115	1
Capehorn	60	Rollins	60	1
Procter	230	Hedge	230	1
Hurley s	230	Procter	230	1
Hurley s	230	Hurley w	230	1
Hurley s	230	Carmical	230	1
Hurley s	230	Elvertas	230	1
Hurley s	230	Hurley	115	1
Elvertas	115	North City	115	1
Nortoma	230	Elverta	230	1
Palermo	230	Palermo	115	1

Attachment C

Overloaded lines/transformers due to Tracy Sub 230 kV East bus section outage requiring identification of mitigation measures

From	To	kV	Loading in % of Rating W/O EAEC	Loading in % of Rating W/ EAEC	Delta (w-wo)
LOSBANOS	LOS BANS	230/70	122.1	127.4	5.3
BRGHTN M	BRIGHTN	230/115	192.4	195.6	3.2
PNCHE 2M	PANOCHE	230/115	137.7	139.8	2.1
PANOCHE	PNCHE 2M	230	138.9	140.9	2
BRGHTN M	BRIGHTN	230/115	220.7	222.3	1.6

Attachment D

Overloaded lines/transformers due to Tracy Sub 230 kV west bus section outage requiring identification of mitigation measures

From	To	kV	Ckt	PCT Rate W/O EAEC	PCT Rate W/EAEC	Delta (w-wo)
LOSBANOS	LOS BANS	230/70	1	124	126.9	2.9
PITSBURG	TASSAJAR	230	1	100.3	102.5	2.2
HEDGE	PROCTER	230	1	114.7	116.6	1.9
CAPEHORN	ROLLINS	60	1	113.8	115.4	1.6
PNCHE 2M	PANOCHE	230/115	2	138.1	139.7	1.6
PANOCHE	PNCHE 2M	230	2	139.3	140.8	1.5
DRUM	BONNIE N	60	1	127	128.5	1.5
CAPEHORN	BONNIE N	60	1	121.1	122.6	1.5
ELLS GTY	TRACY JC	115	1	126.8	127.9	1.1
CHICO B	CHICOTP1	115	1	175.1	176.1	1

ALTERNATIVES

Susan V. Lee

INTRODUCTION

This section considers potential alternatives to the construction and operation of the proposed East Altamont Energy Center (EAEC). The purpose of this alternatives analysis is to comply with State and Federal environmental laws by providing an analysis of a reasonable range of feasible alternative sites which could substantially reduce or avoid any potentially significant adverse impacts of the proposed project (Cal. Code Regs., tit. 14, §15126.6; Cal. Code Regs., tit. 20, § 1765). This section identifies potentially significant impacts of the proposed project and analyzes different technologies and alternative sites that may reduce or avoid significant impacts. Staff has also analyzed the impacts that may be created by locating the project at alternative sites.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

Calpine proposes to interconnect the proposed East Altamont Energy Center (EAEC) to the Tracy substation, which is under the jurisdiction of Western Area Power Administration (Western). Since Western is a federal agency, the EAEC project is subject to review under the National Environmental Policy Act (NEPA) in addition to the California Environmental Quality Act (CEQA). Western is the Lead Agency under NEPA and the California Energy Commission (Energy Commission) is the Lead Agency under CEQA. Western and the Energy Commission are undertaking a combined NEPA/CEQA analysis; this section is intended to function as the alternatives analysis for both processes.

CALIFORNIA ENVIRONMENTAL QUALITY ACT CRITERIA

The “Guidelines for Implementation of the California Environmental Quality Act,” Title 14, California Code of Regulation §15126.6(a), provides direction by requiring an evaluation of the comparative merits of “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 but would avoid or substantially lessen any of the significant effects of the project.” In addition, the analysis must address the “no project” alternative (Cal. Code Regs., tit. 14, §15126.6(e)).

The range of alternatives is governed by the “rule of reason” which requires consideration only of those alternatives necessary to permit informed decision-making and public participation. CEQA states that an environmental document does not have to consider an alternative of which the effect cannot be reasonably ascertained and of which the implementation is remote and speculative (Cal. Code Regs., tit. 14, §15125(d)(5)). However, if the range of alternatives is defined too narrowly, the analysis may be inadequate (City of Santee v. County of San Diego (4th Dist. 1989) 214 Cal. App. 3d 1438).

NATIONAL ENVIRONMENTAL POLICY ACT CRITERIA

NEPA requires that the decision-makers and the public be fully informed of the impacts associated with the proposed project. The intent is to make good decisions based on understanding environmental consequences, and to take actions to protect, restore, and enhance the environment. Western's preliminary EA is intended to provide sufficient evidence and analysis for determining whether to prepare an environmental impact statement and help identify better alternatives and mitigation measures.

Alternatives identified must be consistent with Western's purpose and need for the action under consideration, which include the applicants objectives. The applicant's objectives are described in the Project Objectives section. Western's purpose and need is described In the NEPA Purpose and Need section. For purposes of NEPA analysis, Western may determine that alternative power plant sites are not consistent with the purpose and need or the applicant's objectives. This determination will be made in the EA or draft EIS that will be jointly published with the FSA.

PROJECT DESCRIPTION

The proposed EAEC would be a nominal 1,100-megawatt (MW) natural-gas-fired, generating facility located on approximately 40 acres within a 174-acre parcel. The site is in unincorporated Alameda County, one-mile west of the San Joaquin County line and one-mile southeast of the Contra Costa County line. The land is currently zoned for agricultural uses (EAEC 2001a, Section 2). The EAEC is designed as a 820MW combined cycle power plant, with an additional 267 MW of peaking capacity provided by oversized duct burners and an oversized steam turbine generator.

The proposed power plant would require a 230-kilovolt (kV) switchyard and approximately 0.5 mile of new 230-kV transmission line. The switchyard would be owned by Western and would function as an extension of the existing Tracy substation, which is located immediately west of the proposed project site. Natural gas for the facility would be delivered via approximately 1.4-miles of new 20-inch pipeline that would connect to the Pacific Gas and Electric (PG&E) existing transmission line located at the intersection of Bruns Road and Kelso Road. Byron Bethany Irrigation District (BBID) would supply roughly 4,600 acre-feet of raw water for cooling and process make-up water via a 2.1-mile pipeline (EAEC 2001a, Section 2).

SITE SELECTION

As stated in the AFC, the Applicant chose the proposed site for the following reasons (EAEC 2001a, Section 9)."

- The site is close to an existing transmission substation with access to PG&E, Western, Modesto Irrigation District (MID), Turlock Irrigation District (TID), and through PG&E, the Independent System Operator (ISO) electrical markets;
- Sufficient land is available for the 40-acre site plus a construction lay down area;
- The site is served by a water purveyor with adequate water supply to support the project;

- The site is close to a PG&E natural gas pipeline;
- The site is located in a rural area with few residences nearby;
- The project would be consistent with other neighboring utility uses, such as the transmission substation; and
- Even though the parcel is zoned agricultural, a generating facility could be allowed through a conditional use permit.

SCOPE AND METHODOLOGY OF THE ALTERNATIVES ANALYSIS

The purpose of staff's alternatives analysis is to provide a reasonable range of feasible alternatives that could substantially reduce or avoid any potentially significant adverse impacts of the proposed project. To accomplish this, staff must determine the appropriate scope of analysis. Consequently, it is necessary to identify and determine the potentially significant impacts of the proposed project and then focus on alternatives that are capable of reducing or avoiding significant impacts.

To prepare this alternatives analysis, staff used the following methodology:

- Identify the basic objectives of the project, provide an overview of the project, and describe its potentially significant adverse impacts.
- Identify and evaluate alternatives to the project. The principal project alternatives examined that do not require the construction of a natural gas-fired facility are increased energy efficiency (or demand side management) and the construction of alternative technologies (e.g. wind, solar, or geothermal).
- Identify and evaluate alternative locations or sites.
- Evaluate the impacts of not constructing the project, known as the "no project" alternative under CEQA or the "no action" alternative under NEPA.
- For purposes of the preliminary EA, Western reviewed the results of the Energy Commission alternatives analysis and determined which alternatives were consistent with its purpose and need section. Alternatives not consistent with Western's purposes and need were dismissed from full analysis of the preliminary EA. These alternatives nonetheless remain as part of the Energy Commission's CEQA analysis.

PROJECT OBJECTIVES

Based on analysis of the EAEC Application for Certification (AFC), the Energy Commission staff has determined the project's objectives as:

-
- Construction and operation of a merchant power plant with access to multiple markets;
- To be located near a substation and key infrastructure for natural gas, water supply and transmission lines;

- Generation of approximately 1,100 MW of electricity; and
- To be online by 2004.

NEPA PURPOSE AND NEED STATEMENT

NEED FOR WESTERN ACTION:

Calpine has applied to interconnect with Western's transmission system at it'sTracy Substation. Western must respond to Calpine's request for an interconnection with Western's transmission system.

PURPOSES FOR WESTERN ACTION:

In responding to the Need for Agency Action, Western must abide by the following purposes.

1. **Providing transmission service Per Open Access Transmission Policy**
   Federal Energy Regulatory Commission (FERC) Order Numbers 888 and 888-A requires all public utilities owning or controlling interstate transmission facilities to offer non-discriminatory open access transmission services. That is, a utility must offer to provide third parties, to the maximum extent possible, with transmission service that the utility could provide itself on its system. FERC was addressing the need to encourage lower electricity rates by facilitating the development of competitive wholesale electric power markets through the prevention of unduly discriminatory practices in the provision of transmission services (FERC 1996). Although Western is not specifically subject to the requirements of the FERC Final Order Nos. 888 and 888-A, the DOE has issued a Power Marketing Administration Open Access Transmission Policy that supports the intent of the FERC's Notice of Proposed Rulemaking for Open Access Transmission, which does apply to Western. To comply with FERC Orders 888 and 888A, Western published in the Federal Register on January 6, 1998 its Notice of Final Open Access Transmission Service Tariff (Tariff). Under the Western's Final Open Access Transmission Service Tariff Western offers transmission service for the use of available transmission capacity in excess of the capacity Western requires for the delivery of long-term firm capacity and energy to current contractual electric service customers of the Federal government. Under the Tariff, Western will provide firm and non-firm point-to-point transmission service and network integration transmission service to the extent that Western has available transmission capability.

2. **Addressing an Interconnection Application per Western's General Guidelines for Interconnection**
   Western's General Guidelines for Interconnection provide a process for addressing applications for interconnection. The process dictates that Western respond to an application as presented by an applicant. Section 211 of the Federal Power Act

requires transmission services be provided upon application if transmission capacity is available.

3. **Protect Transmission System Reliability and Service to Existing Customers**
   Western's purpose is to ensure that existing reliability and service is not degraded. Western's General Guidelines for Interconnection involve transmission and system studies to ensure that system reliability and service to existing customers is not adversely affected.

4. **Consideration of the Applicant's Objectives**
   Since the statement of purpose and need affects the extent to which alternatives are considered reasonable, it is important to understand both the agency's purpose and need and that of the applicant.

WESTERN'S DECISION

Western's decision is limited to deciding if the specific power plant proposed by the applicant can be interconnected with Western's transmission system. Western's decision will take into account:

- potential environmental effects of the proposed power plant;
- potential mitigation measures for the power plant and associated infrastructure; and,
- interconnection proposal consistent with Western's purposes, including the applicant's objectives.

POTENTIAL SIGNIFICANT ENVIRONMENTAL IMPACTS

In this PSA, staff has identified the potential for significant environmental effects of the proposed project in five technical areas (summarized below): air quality, biology, land use, visual resources, and soil and water resources. In addition, there is public concern that the power plant is situated close (within 5,000 feet) to a public school.

- **Air Quality**: The EAEC may result in a potentially significant impact in Air Quality. The project has the potential to violate the Federal PSD BACT requirement for NO_x, NH3 and CO emissions. Staff has also found that the project's emissions of NO_x and VOC have the potential to cause significant impacts relative to the state 1-hour and the federal 8-hour ozone air quality standards. Further, the project has the potential to cause significant impacts relative to the state 24-hour PM_{10} and the federal 24-hour $PM_{2.5}$ air quality standards. The proposed emission reduction credits are not adequate to mitigate the project's potential significant impacts to the state and the federal ozone, PM_{10} and $PM_{2.5}$ air quality standards
- **Visual Resources**: The proposed power plant facility is inconsistent with the existing rural character of the area. It would be visible from recreational areas and would affect panoramic scenic views. The applicant's proposed visual resources mitigation measures and screening plan, and staff's proposed mitigation measures and conditions of certification would mitigate the visual impacts of the proposed project. However, as stated above, biology staffs of the Energy Commission, CDFG, and USFWS are concerned about potential biological impacts of the proposed

landscaping. To address this issue, the applicant has prepared a revised landscaping plan, which staff will evaluate in the Final Staff Assessment. If the revised landscape plan would not result in full and timely implementation of staff's proposed landscaping mitigation, or if the mitigation is determined to not be feasible, significant visual impacts from the proposed project structures would remain.

- **Biological Resources**: At present, the requirement that the applicant avoid potentially significant adverse biological impacts from the proposed landscaping conflicts directly with mitigation required to minimize impacts to visual resources. Because the proposed landscaping would provide perching opportunities for raptors, and may harm federally listed species, staff fully supports the position of the California Department of Fish and Game (CDFG) and U.S. Fish and Wildlife Service (USFWS) that the originally proposed landscaping is unacceptable. The most recent landscaping proposal continues to be reviewed and discussed amongst the agencies, the applicant, and staff. Staff needs to receive further information from the applicant on the habitat mitigation and will consult with USFWS and CDFG in order to ensure that the mitigation determined in the FSA is sufficient.

  Biology staff is also concerned about impacts of water diversions from the Delta on native fish. As such, staff requires additional information from DWR and the applicant on water use and impacts to Delta fish. Staff still needs to continue its analysis of impacts to determine if alternative cooling technologies, such as dry cooling, or the use of recycled water are warranted in order to address any potential impacts on Delta fish.

- **Land Use and Soils**: The project site is located on land that is zoned as large parcel agricultural. If Alameda County was the lead agency for this project, the project would be required to obtain a conditional use permit, which in turn would require that the County make certain findings. Staff has requested that the County staff make these findings, which the Commission staff could evaluate and incorporate into its final analysis. Staff has not yet received these conditional use permit findings from Alameda County. Therefore, staff cannot conclude that the project will comply with LORS.
- The proposed site is located on soil that is defined as "Prime Farmland" thus potentially impacting the areas of Land Use and Soils. The Alameda County General Plan specifically states that the County shall preserve farmland and prime soils for agricultural uses. Pending receipt of Alameda County's conditional use permit findings, at this time staff is not able to make a recommendation for certification.
- The applicant is proposing to develop a power generation facility outside of the designated Urban Growth Boundary in an agricultural area that is away from existing urban uses. The conversion of at least 40 acres from an agricultural use to a nonagricultural use (the proposed power plant), including the loss of prime agricultural land, presents potential non-conformity issues with ABAG Regional Goals and Policies under Preservation of Agricultural Resources, and could present a significant impact under CEQA. The applicant and the County of Alameda are negotiating a mitigation agreement that would bring the project into compliance with the ABAG Regional Goals, which staff would need to review for a CEQA analysis.

As of the writing of this PSA, staff has not received a copy of the final agricultural land conversion mitigation agreement between the applicant and the County of Alameda.

- **Water and Soil Resources**: The proposed project could lead to significant adverse impacts as a result of relying on BBID to divert fresh water from the Delta for EAEC's use during all seasons and in quantities uncharacteristic of BBID's historic patterns of diversion. The Department of Water Resources (DWR) has expressed concern that its beneficial uses under the State Water Project, or other Delta beneficial uses including maintenance of plant life, fish and wildlife, could be injured. Staff is awaiting additional information from DWR and the Applicant relative to previous Bay-Delta analyses and the relationship of BBID's water entitlements to those of the SWP and CVP, in order to more fully evaluate the potential impacts from the proposed water supply to EAEC.

SITE ALTERNATIVES

Eight alternative sites were identified as potential power plant site alternatives. The applicant presented six sites as part of its alternatives analysis (Alternative Sites 1 through 6; EAEC 2001a, AFC Section 9). Three of the applicant's sites (Alternatives 1, 3, and 4) were eliminated from this analysis (see explanation under "Alternatives Eliminated" section, below). Staff also identified three additional possible alternative sites, Alternative Sites 7 and 8. Alternative Site 7 was eliminated, but Alternative Site 8 was retained for detailed analysis.

SCREENING CRITERIA USED TO SELECT ALTERNATIVE SITES

The following criteria were used to identify potential alternative sites:

1. Avoid or substantially lessen one or more of the potential significant effects of the project; and
2. Satisfy the following criteria:
   a. Location. In order to meet reliability objectives, the site should be located near major Central Valley transmission lines.
   b. Site suitability. Sufficient land is needed to construct and operate a generating facility of this size. The proposed power plant would be located on 40 acres of land, however only 25 acres is required for a generating facility using the proposed technology. (EAEC 2001a, AFC Section 9) Therefore, staff used 25 acres as the minimum lot size needed to accommodate the facility.
   c. Availability of infrastructure. The site should be within a reasonable distance of natural gas and water supply.

Availability of the site.

Not located adjacent to moderate or high density residential areas or to sensitive receptors (such as schools and hospitals) or to recreation areas.

Four alternative sites are evaluated in detail: Site 2 (Mountain House Road), Site 5 (Bruns Road), Site 6 (Tesla), and Site 8 (Lodi). Please see **ALTERNATIVES Figures 1 through 3** for maps of these four sites.

SITE 2 (MOUNTAIN HOUSE ROAD)

Site 2 is located south of the proposed project site and is situated between the California Aqueduct and the Delta-Mendota Canal. This site is on the eastern side of Mountain House Road, located approximately 1,000 feet southeast of the Bethany Reservoir.

The parcel is in Alameda County and is zoned Agricultural. The site consists of approximately 46 acres of flat land, located within a small valley at the base of the foothills. The site is currently used for grazing.

A PG&E 230-kV transmission line is located approximately 0.5 miles from the site. This site is not located in the BBID service area, and locating a water supply could be problematic. The natural gas pipeline would be less than 0.5 mile long and would pass under the Delta-Mendota Canal to connect to the PG&E pipeline.

Site 2 is within approximately 2.0 miles of a small community, with the nearest residence being approximately 2,000 feet to the east (EAEC 2001a, Section 9). This site is well hidden from view. The parcel bordered by Mountain House Road on the east, but extends to the west in a valley. It is surrounded by hills that would block most views of the site from Mountain House Road. When driving along Mountain House Road, which meanders through low hills in this area, the parcel is only momentarily visible and then blocked by hills surrounding the parcel. To the west of the parcel, there are hills with a wind farm. A railroad right-of-way was observed running west to east on the southern portion of the parcel. A 500-kV transmission line crosses through the site.

Within the site, there are several areas with wetland vegetation. These areas were observed to have heavy bird use.

Advantages

- Minimal visual impacts due to surrounding hills.
- Few nearby residences.
- Good site access from Mountain House Road.

ALTERNATIVES Figure 1
Map of Alternative Sites 2 and 5 (near the Tracy Substation)

ALTERNATIVES Figure 2
Map of Alternative Sites 6 (near the Tesla Substation)

ALTERNATIVES Figure 3
Map of Alternative Site 8 (near Lodi)

Disadvantages

- Existing wetland vegetation with high bird use.
- This site is not located in the BBID service area, and locating a water supply could be difficult. However, using dry cooling technology would be feasible.
- A PG&E 500-kV transmission line bisects the site, which could constrain site development.
- Because a stream runs through this parcel, the potential for flooding needs to be evaluated.

Potential Impacts

- **Air Quality**: The potentially significant impacts of the proposed project would also apply to this site since the project would still have similar emissions and they would affect the same air basin.
- **Biological Resources**: A power plant at this location would be far less visible than the proposed site because it is protected by hills on the south, west, and north. Vegetative screening as mitigation for visual impacts would likely be required only on the east side of the plant and the potential for such vegetation to create biological impacts would need to be reviewed. The site also has apparent wetland areas that would require review.
- **Land Use and Soils**: This land is also zoned Agricultural, however the parcel is not designated as "Prime Farmland". While the Applicant would not need to obtain a conditional use permit, they would still need to comply with the requirements of this permit in order to get Energy Commission approval.
- **Visual Resources:** A power plant at this location would be well hidden from most scenic views and would be visible only briefly to viewers driving on Mountain House Road.
- **Water Resources:** The potentially significant water supply impact of the proposed project would also apply to this site, since no other water supplies have been identified.

SITE 5 (BRUNS ROAD)

Site 5 is located west of the proposed project site, on the west side and north of the Tracy Pumping Station. This site is on the southern side of a small agricultural road that intersects Bruns Road at 7995 Bruns Road, which is the Byron Bethany Irrigation District corporation yard. The site is approximately 1,500 feet east of the Byron Bethany Irrigation District. A majority of the site is located in Alameda County and is zoned Agricultural, with the northwestern portion of the site located in Contra Costa County.

This site is a 207-acre parcel with slightly undulating terrain and is currently open grassland. Several small hills are located on the western edge of the parcel and rise from 10 feet to 135 feet (above sea level). A PG&E 500-kV and a Western 230-kV

electrical transmission line cross the parcel on the western and eastern borders of the site, respectively.

The project would interconnect to the Tracy substation either by connecting to the existing Western 230-kV line on-site or by a new 4,500-foot-long electrical transmission line. The natural gas supply would require a new 4,000-foot-long pipeline. The water supply line would require a 3,000-foot-long pipeline to connect to the BBID take-off point.

The project lies in an area identified by the Contra Costa County Airport Land Use Compatibility Plan (EAEC 2001a, AFC Section 9) as Zone B2. The closest airport is the Byron Airport located 3 miles north of Site 5 at 3000 Armstrong Road in Byron.

There is one residence approximately 0.5-mile to the southwest of this site and several trailer homes immediately south of the parcel, within a quarter mile of the southern boundary. Surrounding the site, there are vineyards immediately to the north and east. The levee of the Delta Mendota Canal is immediately to the east and would block a portion of the view of the power plant from the San Joaquin Valley. To the west, there are wind farms on the hills. The parcel is accessed by a dirt road used for agricultural equipment that leaves Bruns Road to the east at the point where the BBID is located.

Advantages

- Large, undeveloped parcel.
- Good access to transmission lines.
- Less visible than proposed site due to location west of Delta Mendota Canal levee.

Disadvantages

- The parcel for Site 5 is approximately 3 miles away from the Byron Airport. The project lies in an area identified by the Contra Costa County Airport Land Use Compatibility Plan (EAEC 2001a, AFC Section 9) as Zone B2. This zone designation requires any development to obtain an aviation approval from Contra Costa County, prohibits the aboveground storage of bulk hazardous materials, and requires an airspace review to be conducted for structures taller than 50 feet.

Potential Impacts

- **Air Quality**: The potentially significant impacts of the proposed project would also apply to this site since the project would still have similar emissions and they would affect the same air basin.
- **Biological Resources**: A power plant at this location would be visible to travelers on Byron-Bethany Road, and it is likely there would be a need for vegetative screening as mitigation for visual impacts. Therefore, a project at this location may have similar impacts to Biological Resources as the proposed project.
- **Lands Use and Soils**: This land is also zoned Agricultural, however the parcel is not designated as “Prime Farmland.” While the Applicant would not need to obtain a

conditional use permit, they would still need to comply with the requirements of this permit in order to get Energy Commission approval.

- **Visual Resources**: A power plant at this location would likely be less visible than the proposed site; however the extent of visual impact would require additional review.
- **Water Resources**: The potentially significant water supply impact of the proposed project would also apply to this site, since no other water supplies have been identified.

SITE 6 (TESLA)

Site 6 is a 348.68-acre parcel, which is a combination of two parcels consisting of 49.53-acres and 299.1 acres. The site is located north of the Tesla substation in rural, eastern Alameda County. The site is zoned Large-Parcel Agricultural. The site is currently grazing land with wind power generators located on the western side of the site. A major PG&E natural gas pipeline runs approximately 1,000 feet south of the site. On October 12, 2001, Midway Power filed an Application for Certification with the Energy Commission for the Tesla Power Project to be sited on this parcel, but the site is retained for analysis because the site is large enough to accommodate both facilities.

The project would be electrically connected to the Tesla Substation via a new approximately 1,000-foot transmission line. Natural gas would be provided from the PG&E natural gas pipeline via a new 1,000-foot pipeline running through the Tesla substation. The nearest source of water would be the City of Tracy's water service lines near the junction of I-580 and Patterson Pass Road, approximately 2 miles from the site. As discussed in **Water and Soils** section, the City of Tracy can provide recycled water in sufficient quantities to meet the project demand.

Several residences are located approximately 0.5 mile from the site, along Midway Road. A power plant at this site would be visible from Midway Road, a lightly traveled rural road that forms the eastern border of the parcel. West of Midway Road are large hills that would block views from the west, with wind generators and a 500-kV corridor traveling north to south. Wind farms are located to the east and to the west of Site 6. The Tesla Substation is located just south of this site and grazing is taking place between Tesla and Site 6. The site would be visible from Patterson Pass Road, which is designated a historic route called Juan Bautista de Anza.

Transmission lines entering and exiting Tesla Substation traverse the area to the south, east, and west. On the northern boundary of the site, there is an abandoned railroad and old railroad power lines. Electrical interconnection to the Tesla substation provides market access only to PG&E and the ISO, but not the central San Joaquin Valley municipal districts of Modesto and Turlock. There is a small drainage to the south of the site.

Advantages

- Not located on farmland.
- Greater visual screening from surrounding hills.

- Nearby connections to transmission line and natural gas supply.

Disadvantages

- The site would be visible from Patterson Pass Road, which is designated a historic route. However, also in the viewshed at this location is the Tesla Substation and the view from this route is far from pristine. Patterson Pass Road passes along two sides of the Tesla Substation; transmission lines entering and exiting Tesla Substation traverse the area to the south, east, and west of the parcel.
- The National Park Service's Juan Bautista de Anza Historic Trail passes along Midway Road, which would be immediately east of this site.

Potential Impacts

- **Air Quality**: The potentially significant impacts of the proposed project would also apply to this site since the project would still have similar emissions and they would affect the same air basin.
- **Biological Resources**: A power plant at this location would be visible to far fewer viewers than the proposed project. However, vegetative screening would likely be required as mitigation for views from Midway Road and Patterson Pass Road.
- **Lands Use and Soils**: This land is also zoned Agricultural, however the parcel is not designated as "Prime Farmland." Although the Energy Commission's permitting authority supercedes local permitting requirements and therefore it is not required for to the Applicant to obtain a conditional use permit however, EAEC would still need to comply with the requirements of a conditional use permit.
- **Visual Resources**: A power plant at this location would be well hidden from scenic views but would still be visible to drivers on Midway and Patterson Pass Roads, and vegetative screening would likely be required as mitigation. Although Patterson Pass Road is a scenic highway, a power plant at this location would be more consistent with the industrial setting due to the existing Tesla Substation and transmission lines that interconnect to the substation
- **Water Resources**: The City of Tracy has sufficient secondary treated water available to meet project demand. However, as discussed in the **Water and Soils** section, additional treatment of the water would still be required, the City of Tracy is currently building a tertiary water treatment facility that would treat water to acceptable levels.

SITE 8 (LODI)

Site 8 is located about 30 miles north of the proposed EAEC site. This site is adjacent to the City of Lodi's White Slough Pollution Control Plant and the Northern California Power Authority's (NCPA) 50 MW Combustion Turbine project. The City of Lodi currently owns the 900 acres of vacant land surrounding the parcel.

The site is located in San Joaquin County and is zoned Public. The site topography is flat. The site is adjacent to I-5 and was previously used for agricultural uses and much

of the City's land is still leased for agricultural production. The site is currently grass-covered land and is adjacent to paved roads and concrete equipment pads. The site would need to be graded, and substantial additional amounts of soil would have to be imported to raise the site above the 100-year flood level.

The nearest sensitive receptors are several miles to the north and south, areas to the west are agricultural for miles and I-5 is to the east of the site. The nearest residential receptors are more than one mile away; they would almost certainly not able to see or hear a new facility at this site, as its view would be screened by the existing facility, existing vegetation, and I-5.

The NCPA is adjacent to two high voltage transmission circuits, one a 230-kV double-circuit line owned by PG&E, the other a single circuit 230-kV line owned by Western. Gas could be provided by tapping into the approved (but not yet completed) high-pressure gas pipeline being built as part of the Lodi Gas Storage Project (LGSP). The existing service for the NCPA and the sewer treatment plant are not sufficient to handle any additional generation. A new 30-inch line would need to be constructed, under I-5 near Highway 12, about 2.5 miles north of the NCPA plant. The needed gas line may have to travel through wetlands, but the route may be able to be routed alongside I-5 where biological impacts are less likely to occur.

The White Slough plant could supply enough recycled water to meet EAEC's needs except during summer months when water is committed to agricultural use. However, plant management indicated that this commitment of water could be changed, depending on the agreements with the City associated with power plant operation.

Advantages

- Reclaimed water is available from the wastewater treatment plant.
- Good transmission access.
- Good access to natural gas.
- Good construction access from I-5.
- There are not any nearby residences or sensitive receptors.
- Site is adjacent to existing industrial uses (wastewater treatment plant and power plant), and partially screened from viewers on I-5.

Disadvantages

- A power plant at this site would require at least 2 miles of new high-pressure gas line. The gas line may have to travel through wetlands.
- The site has very shallow groundwater and flooding potential, so construction would have to include importing of fill to raise the site above the 100 year flood zone.
- The site is located about 1/2 mile east of the Delta wetlands (White Slough, managed by CDFG and owned by DWR).

Potential Impacts

- **Air Quality**: The potentially significant impacts of the proposed project would also apply to this site since the project would still have similar emissions and they would affect the same air basin.
- **Biological Resources**: Potential impacts on the species occupying the nearby White Slough would need to be evaluated for potential project effects. Because trees are present along the slough just west of the site, any vegetative screening required to mitigate visual impacts would not present new predator perching opportunities in the region.
- **Lands Use and Soils**: This land is also zoned for Public, and a power plant at this location would be consistent with the General Plan.
- **Visual Resources**: A power plant at this location would not be within most scenic views and would be visible primarily to motorists on I-5. While vegetative screening may still be required, a power plant at this site would be located in an industrial setting: adjacent to an existing (smaller) power plant, a large water treatment facility, and existing transmission lines.
- **Water Resources**: If this site were used, the project would use recycled water from the City of Lodi's White Slough Water Pollution Control Facility. Therefore, this site would eliminate the water supply concerns of the proposed site.

NO PROJECT ALTERNATIVE

The "no project" alternative under CEQA or the "no action" alternative under NEPA assumes that the project is not constructed. In the CEQA analysis, the "no project" alternative is compared to the proposed project and determined to be superior, equivalent, or inferior to it. The CEQA Guidelines state that "the purpose of describing and analyzing a No Project Alternative is to allow decision makers to compare the impacts of approving the proposed project with the impacts of not approving the proposed project" (Cal. Code Regs., tit. §15126.6(i)). Toward that end, the No Project analysis considers "existing conditions" and "what would be reasonably expected to occur in the foreseeable future if the project were not approved…" (§15126.6(e)(2)). Under NEPA, the "no action" alternative is used as a benchmark of existing conditions by which the public and decision makers can compare the environmental effects of the proposed action and the alternatives.

The "no project" alternative assumes that the power plant will not be constructed. If this facility were not constructed, the proposed site would remain in agricultural production. In the AFC, the Applicant's main objectives are to meet the objectives of the deregulated energy market, develop new merchant power generation facilities and replace older and less efficient generation facilities.

The proposed EAEC would contribute to California's generating resources, increase competition and help form a more reliable electric system that meets the goals of the deregulated energy market. Due to market forces, the proposed facility may also serve to replace older, inefficient facilities.

If the “no project” alternative is selected, the construction and operational impacts of the EAEC would not occur. The area would remain farmland and the fresh surface water would be available for potable water uses. In addition, the rural character and setting would be preserved. However, California would not have an additional 1,100 MW of electrical generation.

ALTERNATIVES ELIMINATED FROM DETAILED ANALYSIS

This section describes alternatives that did not satisfy the screening criteria for inclusion in the analysis, and include the following:

- Several alternative sites
- Demand side management
- Distributed generation
- Renewable resources.

Each of these alternatives, and the reasons for their not being considered in detail in this analysis, is addressed below.

SITE ALTERNATIVES ELIMINATED FROM THIS ANALYSIS

CEQA guidelines state that the alternatives discussion need not consider alternatives that are either infeasible or do not avoid significant environmental impacts. NEPA does require that the reasons for the elimination be explained in the analysis. The following sections define other sites that were considered as alternatives to the EAEC project and the reasons for their elimination from consideration.

Site 1 (Grant Line Road)

Site 1 is located south of the proposed site and north of Grant Line Road. The Delta Mendota Canal forms the western edge of the parcel and the intersection of Mountain House Parkway and Grant Line Road is the southeastern corner of the parcel. The site is located in Alameda County and is zoned Agricultural. The site is a 154-acre parcel of relatively flat land with rising terrain to the southeast. A portion of the site is currently used for agriculture and the rest is open space. There is an irrigation canal that bisects the parcel along with the irrigation canal that defines the western boundary of the parcel.

A 230-kV transmission line, which runs north to south, is located on the western portion of the parcel. Natural gas delivery would require a 0.5-mile long pipeline. To supply water, a new 4.6-mile long waterline would be constructed from the BBID.

There are approximately 20 to 30 residences along Grant Line Road directly south of this site, adjacent to the southern edge of Site 1. Toward the west, there is a wind farm on a hill, which blocks the view of this site from Mountain House Road. This site was eliminated due to its greater proximity to residential homes and its high visibility.

Site 3 (Mountain House School)

Site 3 was identified by the applicant and is located south of the proposed site, approximately 1,800 feet west of the Mountain House School. Site 3 is located in Alameda County and is zoned Agricultural. The site is approximately 37 acres of flat land.

The nearest residence is located approximately 1,000 feet to the west of Site 3. In addition, there is a residence and the Mountain House School located approximately 2,000 feet to the northeast of Site 3. There is an electrical transmission line running along the east side of the parcel. Visually, there are trees surrounding Mountain House School that would partially block a power plant, however not entirely. The power plant, particularly the stacks, would be visible from Mountain House Road and Kelso Road.

There are several potential issues that would likely arise from situating a power plant close to a schoolhouse. The school would be considered a sensitive receptor during both construction and operation. Concerns include noise, use and transport of hazardous materials, and visual impacts. Although the rural character of the area would make all potential sites sensitive to noise, the school would be a particularly sensitive receptor. The power plant, particularly the stacks, would be visible from Mountain House Road and Kelso Road, which are heavily traveled roads. Therefore, situating the power plant at Site 3 does not reduce or avoid any the significant impacts of the proposed project.

Site 4 (Kelso Road)

Site 4 is located southwest of the proposed site and consists of 158 acres. This site is on the southern side of Kelso Road, located 1,000 feet southeast of the Bethany Reservoir. The site is located in Alameda County and is zoned Agricultural. The site topography is flat on the easternmost edge, then rises gradually to the western side of the parcel to a series of low hills. The PG&E natural gas compressor station is located due north, across Kelso Road. The PG&E natural gas pipeline runs through the parcel at an angle and Kelso Road lies along the northern edge of the site. A set of PG&E 500-kV electrical transmission lines crosses the eastern portion of the parcel.

The land is primarily used for grazing. Wind power generators are scattered in the hills to the southwest of the site and a building owned by the Byron Power Company is also located southwest of the site. The Byron Power Company is a natural gas cogeneration facility that is used to generate power and evaporate wastewater. Also, there is an abandoned wind farm between the parcel and the Byron Power Company.

The site could connect electrically to the 230-kV line approximately 1,000 feet east of the site, or to the Tracy substation via a 2,000-foot-long transmission line. The site could interconnect with the PG&E natural gas pipeline onsite and would not require any offsite infrastructure for gas supply. A 1.3-mile-long water supply pipeline would be required to connect to the BBID water take-off point.

The site is within 500 feet of several residences, with the closest resident less than 250 feet to the east. (EAEC 2001a, Section 9) Furthermore, the elevated terrain requires grading to level the land and the entire parcel is located at a higher elevation than the

surrounding area. Therefore, the power plant would likely be visible from multiple locations, particularly from the San Joaquin Valley, Mountain House Road, Kelso Road, and Byron Bethany Road. There is a drainage channel running through the eastern portion of the parcel, which is also the lowest elevation.

This site was eliminated from detailed analysis because of its potential for significant visual resources, impacts to water resources, and proximity to residences.

Site 7 (I-580)

Site 7 is a parcel of land southwest of the intersection of I-580 and Patterson Pass Road, just south of the existing gas station on the northwest corner of this intersection. However, I-580 is considered a scenic highway and is a heavily traveled roadway. Therefore, visual impacts could also be significant, similar to those of the proposed project. Therefore, this alternative was eliminated from further analysis.

RESULTS OF WESTERN'S REVIEW OF ALTERNATIVE SITES

For purposes of the preliminary EA, Western has determined that none of the siting alternatives analyzed under the Energy Commission alternatives analysis are consistent with Western's purposes and need to provide non-discriminatory open transmission line access.

DEMAND SIDE MANAGEMENT

One alternative to a power generation project could be programs to reduce energy consumption. The Warren-Alquist Act specifically prohibits the Energy Commission from considering conservation programs as alternatives to a proposed generation project (Pub. Resources Code, Section 25305(c)).

While such programs are not considered as alternatives to a proposed project, the Energy Commission is responsible for several such programs, the most notable of which are energy efficiency standards for new buildings and for major appliances. These programs are typically called "energy efficiency," "conservation," or "demand side management" programs. One goal of these programs is to reduce overall electricity use; some programs also attempt to shift such energy use to off-peak periods.

The Energy Commission's Energy Efficiency Standards for Residential and Nonresidential Buildings (Cal. Code Regs., title 24, Part 6) were established in 1978 in response to a legislative mandate to reduce California's energy consumption. The standards are updated periodically to allow consideration and possible incorporation of new energy efficiency technologies and methods. New standards were adopted by the Commission in 2001 as mandated by Assembly Bill 970 to reduce California's electricity demand. The new standards went into effect on June 1, 2001. The standards (along with standards for energy efficient appliances) have saved more than $20 billion in electricity and natural gas costs. It is estimated the standards will save $57 billion by 2011 (CEC, 2001a).

Since the CAISO ordered rolling blackouts in January 2001 as a result of statewide electricity shortages, conservation efforts have resulted in dramatic reductions in

electricity use. Electricity use for each month in 2001 ranged from 5% to 12% less than it was in 2000. Following is an excerpt from Governor Davis' September 1, 2001 press release:

> The weather adjusted figures for August show an overall peak load reduction of 3,250 MW (or 7.7 percent) and after accounting for economic growth, the reduction was 3,796 MW (or 9 percent). The economic growth factor, which is developed from the Employment Development Department data, was 1.3 percent for August. In addition, last August, California had 12 days of Stage 1 or Stage 2 power emergencies. This August, there were no power emergencies. Overall energy use in August was down 1.6 million MWh (or 7 percent).

The California Public Utilities Commission supervises various demand side management programs administered by the regulated utilities, and many municipal electric utilities have their own demand side management programs. The combination of these programs constitutes the most ambitious overall approach to reducing electricity demand administered by any state in the nation.

The Energy Commission is also responsible for determining what the state's energy needs are in the future, using 5 and 12 year forecasts of both energy supply and demand. The Commission calculates the energy use reduction measures discussed above into these forecasts when determining what future electricity needs are, and how much additional generation will be necessary to satisfy the state's needs.

Having considered all of the demand side management that is "reasonably expected to occur" in its forecasts, the Energy Commission then determines how much electricity is needed. The most recent estimation of electricity needs is found in the 1996 Electricity Report.

The Warren-Alquist Act was amended in 1999 to delete the necessity of an Energy Commission finding of "need" in power plant licensing cases. In spite of the state's success in reducing demand in 2001, California continues to grow and overall demand is increasing. As stated in the Commission's most recent need determination, adopted in 1997, it is clear that conservation programs alone cannot displace the need for power generation in California's growing economy. Demand-Side Management is not consistent with Western's purposes and need to provide non-discriminatory open transmission access.

DISTRIBUTED GENERATION

Distributed Generation refers to small-scale stationary applications of electric generating technologies. Distributed power units may be owned by electric or gas utilities, by industrial, commercial, institutional or residential energy consumers, or by independent energy producers. They include generating technologies such as engines, fuel cells, small and "micro" gas turbines, solar photovoltaics (PV), and wind turbines, and may be combined with electric storage technologies such as batteries and flywheels (CEC 2001b).

The Energy Commission recently published a report entitled "Distributed Generation: CEQA Review and Permit Streamlining" (CEC, 2000). Distributed generation is the

generation of electricity from facilities that are smaller than 50 megawatts (MW) in net generating capacity, which is below the Energy Commission's power plant siting jurisdiction. Similarly, the California Public Utilities Commission (CPUC) has no permitting authority over these facilities unless an investor-owned utility will own the distributed generation facility. Instead, local jurisdictions — cities, counties, and air districts — conduct all environmental reviews and issue all required approvals or permits for these facilities.

The Energy Commission received a comment supporting distributed generation at the Public Workshop and Scoping Meeting held on November 14, 2001.

There are several incentive programs designed to provide financial assistance to those interested in operating Distributed Generation systems in California. Senate Bill 1345 (Stats. 2000, Ch. 537, §2-3) directs the Energy Commission to develop and administer a grant program to support the purchase and installation of solar energy and small distributed generation systems. Solar energy systems include solar energy conversion to produce hot water, swimming pool heating, and electricity, as well as battery backup for photovoltaic (PV) applications. Small distributed generation systems include micro-cogeneration, gas turbines, fuel cells, electricity storage technologies (in systems other than PV), and reciprocating internal combustion engines.

However, feasibility and environmental impacts are problems for these technologies. A number of serious barriers, including technical issues, business practices, and regulatory policies, make interconnection to the electrical grid in the United States difficult (Alderfer 2000). Broad use of distributed resources would likely require regulatory support and technological improvements.

Additional problems of specific types of distributed generation include the following:

- **Renewable Energy Sources**. The high cost and limited dispatchability of small-scale renewable energy sources such as solar, wind, and biomass essentially inhibit their market penetration (Iannucci 2000). (See the following section for discussion of larger scale renewable energy.)

- **Fuel Cells.** The present high cost of fuel cells precludes their widespread use.

- **Other Fossil-fueled Systems.** Microturbines and various types of engines can also be used for distributed generation. However, these fossil-fueled technologies have the potential for significant environmental impacts. Potential site-specific impacts include noise. Such systems also have the potential for significant cumulative air quality impacts because individually they are typically small enough to avoid the regulatory requirements for air pollution control. Therefore, use of enough of these systems to constitute an alternative to the proposed project would potentially cause significant unmitigated air quality impacts.

In summary, distributed energy is not a feasible alternative to the proposed project because of technical, institutional, and regulatory barriers. Some types of distributed generation also are not feasible alternatives because they are not presently economical,

and others are also not feasible because they have the potential to cause significant unmitigated environmental impacts. Distributed generation is not consistent with Western's purposes and need to provide non-discriminatory open transmission access.

RENEWABLE RESOURCES

Reliance solely on natural gas fired power plants creates both environmental impacts and a dependence on a single energy source. Therefore, renewable resources are attractive power sources.

Staff examined the principal renewable electricity generation technologies that could serve as alternatives to the proposed project and do not burn fossil fuels. These technologies are geothermal, solar, hydroelectric, wind, and biomass. Each of these technologies could be attractive from an environmental perspective because of the absence or reduced level of air pollutant emissions. However, these technologies also cause environmental impacts and have feasibility problems.

Biomass. Biomass facilities are generally in the 3 to 10 MW range, must overcome significant fuel source reliability issues, have difficulty being economically competitive, and are typically worse from an air quality perspective than natural gas. For these reasons, such a project would not be a feasible alternative, nor would it be likely to sufficiently satisfy project goals.

Solar. California currently produces about 400 MW of power from solar thermal projects. Centralized solar projects using the parabolic trough technology require approximately 5 acres per megawatt. A 1,100 MW plant would require approximately 5,500 acres. Photovoltaic arrays require similar acreage per megawatt.

While solar photovoltaics are technically feasible and California clearly has a climate where this technology would be useful, the cost of these systems currently prohibits their widespread use. Recent estimates by the Energy Commission considered that photovoltaics might be able to provide a maximum of 221 MW of statewide generation over the next 10 years. Implementation of photovoltaics in the near term in the East Altamont area would likely require extensive regulatory support and financing from government sources. Given the project objectives requiring an on-line date of 2004, this technology is not considered to be a feasible project alternative.

Wind. California currently generates about 1800 MW of electricity from 105 separate wind facilities. The areas in California with the best wind resources have already been developed. Centralized wind generation areas generally require 40-50 acres per megawatt, with 1,100 megawatts requiring 44,000 - 55,000 acres. Extensive wind generation would also require additional transmission to serve areas of high demand.

Hydroelectric Power. Hydroelectric resources would require inundation of large land areas in order to generate 1,100 megawatts of electricity. Large hydroelectric facilities generating 1,100 megawatts would inundate at least 55,000 acres with water, resulting in extensive environmental impacts.

Conclusion Regarding Renewable Resources. The renewable technologies discussed above have the advantage of not requiring the burning of fossil fuels and the environmental and resource impacts associated with natural gas fired power. However, these technologies also have the potential to cause significant land use, biological, cultural resource, and visual impacts, and they have substantial cost and regulatory hurdles to overcome before they can provide substantial amounts of power. In summary, staff has eliminated these alternatives because (a) they cannot feasibly meet project objectives, and (b) they have the potential to create potentially significant environmental effects of their own. Renewable resources are not consistent with Western's purposes and need to provide non-discriminatory open transmission access.

CONCLUSIONS

This PSA identifies potential unmitigable impacts of the proposed project in (1) air quality, (2) land use, (3) biology, (4) visual resources, and (5) soil and water resources. The following paragraphs present preliminary comparisons of the four alternative sites with the proposed project. However, because the conclusions are tentative at this time, these comparisons will need to be updated and finalized after resolution of all pending issues.

All site alternatives would have a similar potential to impact air quality since all potential sites would impact the same air basin. All of the alternative sites would have less impact on land use because all four alternative sites are designated for agricultural use but none are designated as Prime Farmland. All four of the Alternative Sites considered in this analysis would be further from sensitive receptors than the proposed site. All four sites would be less visible from scenic or sensitive areas than the proposed project, although Alternative Site 5 has the potential to create a significant visual impact before mitigation. One site (Site 8, Lodi) has available reclaimed water, so water resources impacts at this site would be reduced in comparison to the proposed project.

The No Project Alternative is not preferred because, while the impacts of the proposed project would not occur, the benefits of the project would also be eliminated. These benefits include the potential for elimination of older, less efficient power plants.

REFERENCES

EAEC (East Altamont Energy Center) 2001a. Application for Certification, Volume 1 & Appendices, East Altamont Energy Center (01-AFC-4). Dated March 20, 2001 and docketed on March 29, 2001.

EAEC (East Altamont Energy Center) 2001t. Data Response Set 2C. Dated and docketed September 14, 2001.

Midway Power, LLC. 2001. Application for Certification for Tesla Power Project Alameda County, California. October, 2001.

GENERAL CONDITIONS
INCLUDING
COMPLIANCE MONITORING AND CLOSURE PLAN

Ila Lewis

INTRODUCTION

The project General Conditions Including Compliance Monitoring and Closure Plan (Compliance Plan) have been established as required by Public Resources Code section 25532. The plan provides a means for assuring that the facility is constructed, operated and closed in conjunction with air and water quality, public health and safety, environmental and other applicable regulations, guidelines, and conditions adopted or established by the California Energy Commission (Energy Commission) and specified in the written decision on the Application for Certification or otherwise required by law.

The Compliance Plan is composed of the following elements:

1. General conditions that:

a) set forth the duties and responsibilities of the Compliance Project Manager (CPM), the project owner, delegate agencies, and others;

b) set forth the requirements for handling confidential records and maintaining the compliance record;

c) state procedures for settling disputes and making post-certification changes;

d) 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; and

e) establish requirements for facility closure plans.

2. Specific conditions of certification:

- Specific conditions of certification that follow each technical area contain the measures required to mitigate any and all potential adverse project impacts associated with construction, operation and closure to an insignificant level. Each specific condition of certification also includes a verification provision that describes the method of verifying that the condition has been satisfied.

GENERAL CONDITIONS OF CERTIFICATION

DEFINITIONS

To ensure consistency, continuity and efficiency, the following terms, as defined, apply to all technical areas, including Conditions of Certification:

SITE MOBILIZATION:

Moving trailers and related equipment onto the site, usually accompanied by minor ground disturbance, grading for the trailers and limited vehicle parking, trenching for utilities, installing utilities, grading for an access corridor, and other related activities. Ground disturbance, grading, etc. for site mobilization are limited to the portion of the site necessary for placing the trailers and providing access and parking for the occupants. Site mobilization is for temporary facilities and is therefore not considered construction.

GROUND DISTURBANCE:

Onsite activity that results in the removal of soil or vegetation, boring, trenching or alteration of the site surface. This does not include driving or parking a passenger vehicle, pickup truck, or other light vehicle, or walking on the site.

GRADING:

Onsite activity conducted with earth-moving equipment that results in alteration of the topographical features of the site such as leveling, removal of hills or high spots, or moving of soil from one area to another.

CONSTRUCTION:

[From section 25105 of the Warren-Alquist Act.] Onsite work to install permanent equipment or structures for any facility. Construction does **not** include the following:

a. The installation of environmental monitoring equipment.
b. A soil or geological investigation.
c. A topographical survey.
d. Any other study or investigation to determine the environmental acceptability or feasibility of the use of the site for any particular facility.
e. Any work to provide access to the site for any of the purposes specified in a., b., c., or d.

START OF COMMERCIAL OPERATION

1. The project startup team has completed work.
2. The plant manager accepts control from the construction manager.
3. Expenses for the project are switched from construction to operation.
4. The facility has reached steady state with reliability at the rated capacity.
5. Financing accounting switches from construction (capital costs) to operations (Income-producing expenses) financing.

COMPLIANCE PROJECT MANAGER (CPM) RESPONSIBILITIES

A CPM will oversee the compliance monitoring and shall be responsible for:

1. ensuring that the design, construction, operation, and closure of the project facilities is in compliance with the terms and conditions of the Commission Decision;
2. resolving complaints;

3. processing post-certification changes to the conditions of certification, project description, and ownership or operational control;
4. documenting and tracking compliance filings; and,
5. ensuring that the compliance files are maintained and accessible.

The CPM is the contact person for the Energy Commission and will consult with appropriate responsible agencies and the Energy Commission when handling disputes, complaints and amendments.

All project compliance submittals are submitted to the CPM for processing. Where a submittal required by a condition of certification requires CPM approval, it should be understood that the approval would involve all appropriate staff and management.

The Commission has established a toll free compliance telephone number of **1-800-858-0784** for the public to contact the Commission about power plant construction or operation-related questions, complaints or concerns.

Pre-Construction and Pre-Operation Compliance Meeting

The CPM may schedule pre-construction and pre-operation compliance meetings prior to the projected start-dates of construction, plant operation, or both. The purpose of these meetings will be to assemble both the Energy Commission's and the project owner's technical staff to review the status of all pre-construction or pre-operation requirements and milestones contained in the Energy Commission's conditions of certification to confirm that they have been met, or if they have not been met, to ensure that the proper action is taken. In addition, these meetings shall ensure, to the extent possible, that Energy Commission conditions will not delay the construction and operation of the plant due to oversight or inadvertence and to preclude any last minute, unforeseen issues from arising. 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 shall maintain as a public record, in either the Compliance file or Docket file, for the life of the project (or other period as required):

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 complaints of noncompliance filed with the Energy Commission; and,
4. all petitions for project or condition changes and the resulting staff or Energy Commission action taken.

PROJECT OWNER RESPONSIBILITIES

It is the responsibility of the project owner to ensure that the general compliance conditions and the conditions of certification are satisfied. The general compliance conditions regarding post-certification changes specify measures that the project owner

must take when requesting changes in the project design, compliance conditions, or ownership. Failure to comply with any of the conditions of certification or the general compliance conditions may result in reopening of the case and revocation of Energy Commission certification, an administrative fine, or other action as appropriate.

Access

The CPM, responsible Energy Commission staff, and delegate agencies or consultants, shall be guaranteed and granted unrestricted access to the power plant site, related facilities, project-related staff, and the records maintained on site, for the purpose of conducting audits, surveys, inspections, or general 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.

Compliance Record

The project owner shall maintain project files on-site or at an alternative site approved by the CPM, for the life of the project. The files shall contain copies of all "as-built" drawings, all documents submitted as verification for conditions, and all other project-related documents for the life of the project, unless a lesser period is specified by the conditions of certification.

Energy Commission staff and delegate agencies shall, upon request to the project owner, be given unrestricted access to the files.

Compliance Verifications

Each condition of certification is followed by a means of verification. The verification describes the Energy Commission's procedure(s) to ensure post-certification compliance with adopted conditions. The verification procedures, unlike the conditions, may be modified, as necessary by the CPM, and in most cases without full Energy Commission approval.

Verification of compliance with the conditions of certification can be accomplished by:

1. reporting on the work done and providing the pertinent documentation in monthly and/or annual compliance reports filed by the project owner or authorized agent as required by the specific conditions of certification;
2. appropriate letters from delegate agencies verifying compliance;
3. Energy Commission staff audits of project records; and/or
4. Energy Commission staff inspections of mitigation and/or other evidence of mitigation.

Verification lead times (e.g., 90, 60 and 30-days) associated with start of construction may require the project owner to file submittals during the certification process, particularly if construction is planned to commence shortly after certification.
A cover letter from the project owner or authorized agent is required for all compliance submittals and correspondence pertaining to compliance matters. **The cover letter subject line shall identify the involved condition(s) of certification by condition number and include a brief description of the subject of the submittal**. The project owner shall also identify those submittals **not** required by a condition of certification with a statement such as: "This submittal is for information only and is not required by a

specific condition of certification." When submitting supplementary or corrected information, the project owner shall reference the date of the previous submittal.

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 by the project owner or an agent of the project owner.

All submittals shall be addressed as follows:

Compliance Project Manager
California Energy Commission
1516 Ninth Street (MS-2000)
Sacramento, CA 95814

If the project owner desires Energy Commission staff action by a specific date, they shall so state in their submittal and include a detailed explanation of the effects on the project if this date is not met.

Compliance Reporting

There are two different compliance reports that the project owner must submit to assist the CPM in tracking activities and monitoring compliance with the terms and conditions of the Commission Decision. During construction, the project owner or authorized agent will submit Monthly Compliance Reports. During operation, an Annual Compliance Report must be submitted. These reports, and the requirement for an accompanying compliance matrix, are described below. The majority of the conditions of certification require that compliance submittals be submitted to the CPM in the monthly or annual compliance reports.

Compliance Matrix

A compliance matrix shall be submitted by the project owner to the CPM along with each monthly and annual compliance report. The compliance matrix is intended to provide the CPM with the current status of all compliance conditions in a spreadsheet format. The compliance matrix must identify:

1. the technical area,
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., 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 for each condition (e.g., "not started", "in progress" or "completed date"), and

8. the project's preconstruction and construction milestones, including dates and status.

Completed or satisfied conditions do not need to be included in the compliance matrix after they have been identified as completed/satisfied in at least one monthly or annual compliance report.

Pre-Construction Matrix

Prior to commencing construction a compliance matrix addressing only those conditions that must be fulfilled before the start of construction shall be submitted by the project owner to the CPM. This matrix will be included with the project owner's **first** compliance submittal. It will be in the same format as the compliance matrix referenced above.

Tasks Prior to Start of Construction

Construction shall not commence until the pre-construction matrix is submitted, all pre-construction conditions have been complied with, and the CPM has issued a letter to the project owner authorizing construction. Project owners frequently anticipate starting project construction as soon as the project is certified. In some cases it may be necessary for the project owner to file submittals prior to certification if the required lead-time for a required compliance event extends beyond the date anticipated for start of construction. It is also important that the project owner understand that pre-construction activities that are initiated prior to certification are performed at the owner's own risk. Failure to allow specified lead-time may cause delays in start of construction.

Various lead times for verification submittals to the CPM for conditions of certification are established to allow sufficient staff time to review and comment, and if necessary, allow the project owner to revise the submittal in a timely manner. This will ensure that project construction may proceed according to schedule.

Monthly Compliance Report

The first Monthly Compliance Report is due the month following the Energy Commission business meeting date on which the project was approved, unless otherwise agreed to by the CPM. The first Monthly Compliance Report shall include an initial list of dates for each of the events identified on the Key Events List. The Key Events List is found at the end of this section.

During pre-construction and construction of the project, the project owner or authorized agent shall submit an original and five copies of the Monthly Compliance Report within 10 working days after the end of each reporting month. Monthly Compliance Reports shall be clearly identified for the month being reported. The reports shall contain at a minimum:

1. a summary of the current project construction and milestones 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, and should be submitted as attachments to the Monthly Compliance Report;

3. an initial, and thereafter updated, compliance matrix which shows the status of all conditions of certification and preconstruction and construction milestones (fully satisfied and/or closed conditions do not need to be included in the matrix after they have been reported as closed);
4. a list of conditions and milestones that have been satisfied during the reporting period, and a description or reference to the actions which 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 conditions of certification;
7. a listing of any filings with, 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 or milestones;
9. a listing of the month's additions to the on-site compliance file; and
10. any requests to dispose of items that are required to be maintained in the project owner's compliance file.
11. a listing of complaints, notices of violation, official warnings, and citations received during the month; a description of the resolution of any complaints which have been resolved, and the status of any unresolved complaints.

Annual Compliance Report

After the air district has issued a Permit to Operate, the project owner shall submit Annual Compliance Reports instead of Monthly Compliance Reports. The reports are for each year of commercial operation and are due to the CPM each year at a date agreed to by the CPM. Annual Compliance Reports shall be submitted over the life of the project unless otherwise specified by the CPM. Each Annual Compliance Report shall identify the reporting period and shall contain the following:

1. an updated compliance matrix which shows the status of all conditions of certification (fully satisfied and/or closed conditions do not need to be included in the matrix after they have been reported as closed);
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, and should be submitted as attachments to the Annual Compliance Report;
4. a cumulative listing of all post-certification changes approved by the Energy Commission or cleared by 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 made to, or permits issued by, other governmental agencies during the year;

1. a projection of project compliance activities scheduled during the next year;

2. a listing of the year's additions to the on-site compliance file, and

3. an evaluation of the on-site contingency plan for unexpected facility closure, including any suggestions necessary for bringing the plan up to date [see General Conditions for Facility Closure addressed later in this section].

4. a listing of complaints, notices of violation, official warnings, and citations received during the year; a description of the resolution of any complaints which have been resolved, and the status of any unresolved complaints.

Confidential Information

Any information, which the project owner deems confidential shall be submitted to the Energy Commission's Docket with an application for confidentiality pursuant to Title 20, California Code of Regulations, section 2505(a). Any information, which is determined to be confidential, shall be kept confidential as provided for in Title 20, California Code of Regulations, section 2501 et. seq.

Department of Fish and Game Filing Fee

Pursuant to the provisions of Fish and Game Code Section 711.4, the project owner shall pay a filing fee in the amount of eight hundred and fifty dollars ($850). The payment instrument shall be provided to the Commission's Project Manager at the time of project certification and shall be made payable to the California Department of Fish and Game. The Commission's Project Manager will submit the payment to the Office of Planning and Research at the time of filing of the notice of decision pursuant to Public Resources Code Section 21080.5.

Reporting of Complaints, Notices, and Citations

Prior to the start of construction, the project owner must send a letter to property owners living within one 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 24 hours per day, it shall include automatic answering, with date and time stamp recording. All recorded inquiries shall be responded to within 24 hours. The telephone number shall be posted at the project site and made easily visible to passersby during construction and operation. The telephone number shall be provided to the CPM who will post it on the Energy Commission's web page at www.energy.ca.gov/sitingcases. Any changes to the telephone number shall be submitted immediately to the CPM who will update the web page.

In addition to the monthly and annual compliance reporting requirements described above, the project owner shall report and provide copies of all complaint forms, notices of violation, notices of fines, official warnings, and citations, within 10 days of receipt, to the CPM. Complaints shall be logged and numbered. Noise complaints shall be recorded on the form provided in the **NOISE** conditions of certification. All other complaints shall be recorded on the complaint form on the following page.

COMPLAINT REPORT/RESOLUTION FORM

PROJECT NAME:
AFC Number:

COMPLAINT LOG NUMBER _____
Complainant's name and address:

Phone number:

Date and time complaint received:

Indicate if by telephone or in writing (attach copy if written):
Date of first occurrence:

Description of complaint (including dates, frequency, and duration):

Findings of investigation by plant personnel:

Indicate if complaint relates to violation of a CEC requirement:
Date complainant contacted to discuss findings:

Description of corrective measures taken or other complaint resolution:

Indicate if complainant agrees with proposed resolution:
If not, explain:

Other relevant information:

If corrective action necessary, date completed:
Date first letter sent to complainant: _____(copy attached)
Date final letter sent to complainant: _____(copy attached)

This information is certified to be correct.
Plant Manager's Signature: _____ Date:

(Attach additional pages and supporting documentation, as required.)

CONSTRUCTION MILESTONES

The following is the procedure for establishing and enforcing milestones, which include milestone dates for pre-construction and construction phases of the project as required by the Governor's Executive Order D-25-01.

Milestones, and method of verification must be established and agreed upon by the project owner and the CPM no later than 30 days after project approval, the date of docketing. If this deadline is not met, the CPM will establish the milestones.

I. ESTABLISH PRE-CONSTRUCTION MILESTONES TO ENABLE START OF CONSTRUCTION WITHIN ONE YEAR OF CERTIFICATION

1. Obtain site control.
2. Obtain financing.
3. Mobilize site.
4. Begin rough grading for permanent structures (start of construction).

II. ESTABLISH CONSTRUCTION MILESTONES FROM DATE OF START OF CONSTRUCTION

1. Begin pouring major foundation concrete.
2. Begin installation of major equipment.
3. Complete installation of major equipment.
4. Begin gas pipeline construction.
5. Complete gas pipeline interconnection.
6. Begin T-line construction.
7. Complete T-line interconnection.
8. Begin commercial operation.

The CPM will negotiate the above-cited pre-construction and construction milestones with the project owner based on an expected schedule of construction. The CPM may agree to modify the final milestones from those listed above at any time prior to or during construction if the project owner demonstrates good-cause for not meeting the originally-established milestones. Otherwise, failure to meet milestone dates without a finding of good cause is considered cause for possible forfeiture of certification or other penalties.

III. A FINDING THAT THERE IS GOOD CAUSE FOR FAILURE TO MEET MILESTONES WILL BE MADE IF ANY OF THE FOLLOWING CRITERIA ARE MET:

1. The change in any milestone does not change the established commercial operation date milestone.
2. The milestone is changed due to circumstances beyond the project owner's control.
3. The milestone will be missed, but the project owner demonstrates a good-faith effort to meet the project milestone.
4. The milestone will be missed due to unforeseen natural disasters or acts of God which prevent timely completion of the milestones.

5. The milestone is missed due to requirements jof the California ISO to maintain existing generation output.

If a milestone date cannot be met, the CPM will make a determination whether the project owner has demonstrated good cause for failure to meet the milestone. If the determination is that good cause exists, the CPM will negotiate revised milestones.

If the project owner fails to meet one or more of the established milestones, and the CPM determines that good cause does not exist, the CPM will make a recommendation to the Executive Director. Upon receiving such recommendation, the Executive Director will take one of the following actions.

1. Conclude that good cause exists and direct that revised milestones be established; or
2. Issue a reprimand, impose a fine, or take other appropriate remedial action and direct that revised milestones be established; or
3. Recommend, after consulting with the Siting Committee, that the Commission issue a finding that the project owner has forfeited the project's certification.

The project owner has the right to appeal a finding of no good cause, or any recommended remedial action to the full Commission.

FACILITY 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 project 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 which provide the flexibility to deal with the specific situation and project setting which that exist at the time of closure. 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.

There are at least three circumstances in which a facility closure can take place, planned closure, unexpected temporary closure and unexpected permanent closure**.**

PLANNED CLOSURE

A planned closure occurs at the end of a project's life, when the facility is closed in an anticipated, orderly manner, at the end of its useful economic or mechanical life, or due to gradual obsolescence.

UNEXPECTED TEMPORARY CLOSURE

An unplanned unexpected 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.

UNEXPECTED PERMANENT CLOSURE

An unplanned unexpected permanent closure occurs if the project owner closes the facility suddenly and/or unexpectedly, on a permanent basis. This includes unexpected closure where the owner remains accountable for implementing the on-site contingency plan. It can also include unexpected closure where the project owner is unable to implement the contingency plan, and the project is essentially abandoned.

GENERAL CONDITIONS FOR FACILITY CLOSURE

PLANNED CLOSURE

In order to ensure that a planned facility closure does not create adverse impacts, a closure process that provides for careful consideration of available options and applicable laws, ordinances, regulations, standards, and local/regional plans in existence at the time of closure, will be undertaken. To ensure adequate review of a planned project closure, the project owner shall submit a proposed facility closure plan to the Energy Commission for review and approval at least twelve months prior to commencement of closure activities (or other period of time agreed to by the CPM). The project owner shall file 120 copies (or other number of copies agreed upon by the CPM) of a proposed facility closure plan with the Energy Commission.
The plan shall:

1. identify and discuss any impacts and mitigation to address significant adverse impacts associated with proposed closure activities and to address facilities, equipment, or other project related remnants that will remain at the site.

2. identify a schedule of activities for closure of the power plant site, transmission line corridor, and all other appurtenant facilities constructed as part of the project;

3. identify any facilities or equipment intended to remain on site after closure, the reason, and any future use; and

4. address conformance of the plan with all applicable laws, ordinances, regulations, standards, local/regional plans in existence at the time of facility closure, and applicable conditions of certification.

Also, in the event that there are significant issues associated with the proposed facility closure plan's approval, or the desires of local officials or interested parties are inconsistent with the plan, the CPM shall hold one or more workshops and/or the Commission may hold public hearings as part of its approval procedure.

In addition, prior to submittal of the proposed facility closure plan, a meeting shall be held between the project owner and the Commission CPM for the purpose of discussing the specific contents of the plan.

As necessary, prior to, or during the closure plan process, the project owner shall take appropriate steps to eliminate any immediate threats to public health and safety and the

environment, but shall not commence any other closure activities, until Commission approval of the facility closure plan is obtained.

UNEXPECTED TEMPORARY CLOSURE

In order to ensure that public health and safety and the environment are protected in the event of an unexpected temporary facility closure, it is essential to have an on-site contingency plan in place. The on-site contingency plan will help to ensure that all necessary steps to mitigate public health and safety, and environmental impacts, are taken in a timely manner.

The project owner shall submit an on-site contingency plan for CPM review and approval. The plan shall be submitted no less that 60 days (or other time agreed to by the CPM) prior to commencement of commercial operation. The approved plan must be in place prior to commercial operation of the facility and shall be kept at the site at all times.

The project owner, in consultation with the CPM, will update the on-site contingency plan as necessary. The CPM may require revisions to the on-site contingency plan over the life of the project. In the annual compliance reports submitted to the Energy Commission, the project owner will review the on-site contingency plan, and recommend changes to bring the plan up to date. Any changes to the plan must be approved by the CPM.

The on-site contingency plan shall provide for taking immediate steps to secure the facility from trespassing or encroachment. In addition, for closures of more than 90 days (unless other arrangements are agreed to by the CPM), the plan shall provide for removal of hazardous materials and hazardous wastes, draining of all chemicals from storage tanks and other equipment and the safe shutdown of all equipment (also see specific conditions of certification for the technical areas of Hazardous Materials Management and Waste Management).

In addition, consistent with requirements under unexpected permanent closure addressed below, the nature and extent of insurance coverage, and major equipment warranties must also be included in the on-site contingency plan. In addition, the status of the insurance coverage and major equipment warranties must be updated in the annual compliance reports.

In the event of an unexpected temporary closure, the project owner shall notify the CPM, as well as other responsible agencies, by telephone, fax, e-mail, etc., within 24 hours and shall take all necessary steps to implement the on-site contingency plan. The project owner shall keep the CPM informed of the circumstances and expected duration of the closure.
If the CPM determines that a temporary closure is likely to be permanent, or for a duration of more than twelve months, a closure plan consistent with that for a planned closure shall be developed and submitted to the CPM within 90 days of the CPM's determination (or other period of time agreed to by the CPM).

UNEXPECTED PERMANENT CLOSURE

The on-site contingency plan required for unexpected temporary closure shall also cover unexpected permanent facility closure. All of the requirements specified for unexpected temporary closure shall also apply to unexpected permanent closure.

In addition, the on-site contingency plan shall address how the project owner will ensure that all required closure steps will be successfully undertaken in the unlikely event of abandonment.

In the event of an unexpected permanent closure, the project owner shall notify the CPM, as well as other responsible agencies, by telephone, fax, e-mail, etc., within 24 hours and shall take all necessary steps to implement the on-site contingency plan. The project owner shall keep the CPM informed of the status of all closure activities.

A closure plan consistent with that for a planned closure shall be developed and submitted to the CPM within 90 days of the permanent closure (or other period of time agreed to by the CPM).

DELEGATE AGENCIES

To the extent permitted by law, the Energy Commission may delegate authority for compliance verification and enforcement to various state and local agencies that have expertise in subject areas where specific requirements have been established as a condition of certification. If a delegate agency does not participate in this program, the Energy Commission staff will establish an alternative method of verification and enforcement. Energy Commission staff reserves the right to independently verify compliance.

In performing construction and operation monitoring of the project, the Energy Commission staff acts as, and has the authority of, the Chief Building Official (CBO). The Commission staff retains this authority when delegating to a local CBO. Delegation of authority for compliance verification includes the authority for enforcing codes, the responsibility for code interpretation where required, and the authority to use discretion, as necessary, in implementing the various codes and standards.

Whenever an agency's responsibility for a particular area is transferred by law to another entity, all references to the original agency shall be interpreted to apply to the successor entity.

ENFORCEMENT

The Energy Commission's legal authority to enforce the terms and conditions of its Decision is specified in Public Resources Code sections 25534 and 25900. The Energy Commission may amend or revoke the certification for any facility, and may impose a civil penalty for any significant failure to comply with the terms or conditions of the Commission Decision. The specific action and amount of any fines the Commission may impose would take into account the specific circumstances of the incident(s). This would include such factors as the previous compliance history, whether the cause of the

incident involves willful disregard of LORS, inadvertence, unforeseeable events, and other factors the Commission may consider.

Moreover, to ensure compliance with the terms and conditions of certification and applicable laws, ordinances, regulations, and standards, delegate agencies are authorized to take any action allowed by law in accordance with their statutory authority, regulations, and administrative procedures.

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 1230 et. seq., but in many instances the noncompliance can be resolved by using the informal dispute resolution process. Both the informal and formal complaint procedure, as described in current State law and regulations, are described below. They shall be followed unless superseded by current law or regulations.

INFORMAL DISPUTE RESOLUTION PROCEDURE

The following procedure is designed to informally resolve disputes concerning interpretation of compliance with the requirements of this compliance plan. The project owner, the Energy Commission, or any other party, including members of the public, may initiate this procedure for resolving a dispute. Disputes may pertain to actions or decisions made by any party including the Energy Commission's delegate agents.

This procedure may precede the more formal complaint and investigation procedure specified in Title 20, California Code of Regulations, section 1230 et. seq., but is not intended to be a substitute for, or prerequisite to it. This informal procedure may not be used to change the terms and conditions of certification as approved by the Energy Commission, although the agreed upon resolution may result in a project owner, or in some cases the Energy Commission staff, proposing an amendment.

The procedure encourages all parties involved in a dispute to discuss the matter and to reach an agreement resolving the dispute. If a dispute cannot be resolved, then the matter must be referred to the full Energy Commission for consideration via the complaint and investigation process. The procedure for informal dispute resolution is as follows:

Request for Informal Investigation

Any individual, group, or agency may request the Energy Commission to conduct an informal investigation of alleged noncompliance with the Energy Commission's terms and conditions of certification. All requests for informal investigations shall be made to the designated CPM.

Upon receipt of a request for informal investigation, the CPM shall promptly notify the project owner of the allegation by telephone and letter. All known and relevant information of the alleged noncompliance shall be provided to the project owner and to the Energy Commission staff. The CPM will evaluate the request and the information to determine if further investigation is necessary. If the CPM finds that further investigation

is necessary, the project owner will be asked to promptly investigate the matter and within seven (7) working days of the CPM's request, provide a written report of the results of the investigation, including corrective measures proposed or undertaken, to the CPM. Depending on the urgency of the noncompliance matter, the CPM may conduct a site visit and/or request the project owner to provide an initial report, within forty-eight (48) hours, followed by a written report filed within seven (7) days.

Request for Informal Meeting

In the event that either the party requesting an investigation or the Energy Commission staff is not satisfied with the project owner's report, investigation of the event, or corrective measures undertaken, either party may submit a written request to the CPM for a meeting with the project owner. Such request shall be made within fourteen (14) days of the project owner's filing of its written report. Upon receipt of such a request, the CPM shall:

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 agency with expertise in the subject area of concern as necessary;

3. conduct such meeting in an informal and objective manner so as to encourage the voluntary settlement of the dispute in a fair and equitable manner; and,

4. after the conclusion of such a meeting, promptly prepare and distribute copies to all in attendance and to the project file, a summary memorandum which fairly and accurately identifies the positions of all parties and any conclusions reached. If an agreement has not been reached, the CPM shall inform the complainant of the formal complaint process and requirements provided under Title 20, California Code of Regulations, section 1230 et. seq.

FORMAL DISPUTE RESOLUTION PROCEDURE-COMPLAINTS AND INVESTIGATIONS

If either the project owner, Energy Commission staff, or the party requesting an investigation is not satisfied with the results of the informal dispute resolution process, such party may file a complaint or a request for an investigation with the Energy Commission's General Counsel. Disputes may pertain to actions or decisions made by any party including the Energy Commission's delegate agents. Requirements for complaint filings and a description of how complaints are processed are in Title 20, California Code of Regulations, section 1230 et. seq.

The Chairman, upon receipt of a written request stating the basis of the dispute, may grant a hearing on the matter, consistent with the requirements of noticing provisions. The Commission shall have the authority to consider all relevant facts involved and make any appropriate orders consistent with its jurisdiction (Title 20, California Code of Regulations, sections 1232 - 1236).

POST CERTIFICATION CHANGES TO THE COMMISSION DECISION: AMENDMENTS, INSIGNIFICANT PROJECT CHANGES AND VERIFICATION CHANGES

The project owner must petition the Energy Commission, pursuant to Title 20, California Code of Regulations, section 1769, to 1) delete or change a condition of certification; 2) modify the project design or operational requirements; and 3) transfer ownership or operational control of the facility.

A petition is required for **amendments** and for **insignificant project changes**. For verification changes, a letter from the project owner is sufficient. In all cases, the petition or letter requesting a change should be submitted to the Commission's Docket in accordance with Title 20, California Code of Regulations, section 1209.
The criteria that determine which type of change process applies are explained below.

AMENDMENT

A proposed change will be processed as an amendment if it involves a change to the requirement or protocol (and in some cases the verification) portion of a condition of certification, an ownership or operator change, or a potential significant environmental impact.

INSIGNIFICANT PROJECT CHANGE

The proposed change will be processed as an insignificant project change if it does not require changing the language in a condition of certification, have a potential for significant environmental impact, and cause the project to violate laws, ordinances, regulations or standards.

VERIFICATION CHANGE

The proposed change will be processed as a verification change if it involves only the language in the verification portion of the condition of certification. This procedure can only be used to change verification requirements that are of an administrative nature, usually the timing of a required action. In the unlikely event that verification language contains technical requirements, the proposed change must be processed as an amendment.

KEY EVENT LIST

PROJECT: _____

DOCKET #: _____

COMPLIANCE PROJECT MANAGER: _____

EVENT DESCRIPTION	DATE
Certification Date	
Online Date	
POWER PLANT SITE ACTIVITIES	
Start Site Mobilization	
Start Ground Disturbance	
Start Rough Grading	
Start Construction	
First Combustion of Gas Turbine	
Start Commercial Operation	
Complete All Construction	
TRANSMISSION LINE ACTIVITIES	
Start T/L Construction	
SYNCHRONIZATION WITH GRID	
COMPLETE T/L CONSTRUCTION	
FUEL SUPPLY LINE ACTIVITIES	
Start Fuel Supply Line Construction	
COMPLETE FUEL SUPPLY LINE CONSTRUCTION	
WATER SUPPLY LINE ACTIVITIES	
START WATER SUPPLY LINE CONSTRUCTION	
COMPLETE WATER SUPPLY LINE CONSTRUCTION	

EAST ALTAMONT POWER PLANT PROJECT
PREPARATION TEAM

Executive Summary……...Cheri Davis

Introduction……..Cheri Davis

Project Description…….Cheri Davis

Response to Agency & Public Comments……..Cheri Davis

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Biological Resources…….Andrea Erichsen

Cultural Resources……...Roger Mason and Rick Tyler

Hazardous Materials……Alvin Greenburg Ph.D.

Land Use……....Negar Vahidi and Ellen Allan

Noise and Vibration……..Jim Buntin

Public Health……Obed Odoemelam, Ph.D.

Socioeconomics…….James Adams.

Soil and Water……Lorraine White, John Scrrogs, Jim Henniforth and John Kesler

Traffic and Transportation……Davis Flores

Transmission Line Safety and Nuisance……Obed Odoemelam, Ph.D.

Visual Resources……..Michael Clayton and Will Walters

Waste Management……Obed Odoemelam Ph.D.

Worker Safety and Fire Protection……Alvin Greenburg Ph.D. and Rick Tyler

Facility Design……Brian Payne

Geology and Paleontology……..Dr. Dal Hunter

Power Plant Efficiency……Steve Baker

Power Plant Reliability……Steve Baker

Transmission System Engineering……...Ajoy Guha and Al McCuen

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