EAST ALTAMONT ENERGY CENTER
FINAL STAFF ASSESSMENT / ENVIRONMENTAL ASSESSMENT

EXECUTIVE SUMMARY

INTRODUCTION

This Final Staff Assessment (FSA)/ 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, the switching station, natural gas lines, water supply lines, and wastewater lines are under the Energy Commission's jurisdiction (Pub. Resources Code § 25500). When issuing a license, the Energy Commission is the 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 (Pub. Resources Code, § 21080.5; 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 applicant has applied to interconnect its power plant 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 power 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 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 FSA/ Western 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 FSA/ EA were prepared in accordance with:

Public Resources Code section 25500 et seq.;

the California Code of Regulations, title 20, section 12001 et seq.;

the California Environmental Quality Act (Pub. Resources Code, § 21000 et seq.) and its guidelines (Cal. Code Regs, tit. 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).

With respect to the California Energy Commission's process, this FSA is not the decision document for these proceedings. It represents conclusions at the staff level only. The final decision will be made by the Commissioners of the California Energy Commission only after the completion of the evidentiary hearings. The Commissioners will consider the recommendations of all interested parties, including those of the Energy Commission staff; the applicant; intervenors; members of the public; and local, state, and federal agencies, before making a final decision on the application to construct and operate the EAEC.

For Western, this document serves as the Final EA, which serves to support a Western determination on whether or not to prepare an Environmental Impact Statement (EIS). For purposes of the NEPA process, Western will determine the significance of impacts in a separate determination issued after the Final EA. Western will consider the Final EA and subsequent public, agency and tribal comments on the Final EA in making this determination. If Western determines there are no significant impacts it will issue a Finding of No Significant Impact (FONSI). A preliminary version of the FONSI will be made available for public review for at least 30 days. Publishing a final FONSI will complete the assessment portion of the federal environmental process. If Western determines there are significant impacts, it will publish a notice of intent to prepare an EIS in the Federal Register and distribute copies to the project's mailing list. An EIS will then be developed using the results of the Final EA and other analyses, and issued for public comment. If an EIS is needed, Western will independently publish a final EIS and Record of Decision before completing the federal environmental process.

For purposes of the NEPA process, Western's conclusions about significance may vary from the conclusions reached by Energy Commission staff and the Energy Commission. Western will consider the FSA/EA findings and Energy Commission determinations, but may apply different weightings to the Commission staff's significance criteria or may consider different criteria altogether. For example, Federal regulations do not apply to the proposed project's potential impacts on visual resources. Therefore, Western is likely to put greater emphasis on compliance with local ordinances and plans. Western will also consider other factors such as the strong presence of the Tracy Substation and the many transmission lines radiating from it.

PROJECT LOCATION AND DESCRIPTION

On March 29, 2001, East Altamont Energy Center, LLC, a wholly owned subsidiary of Calpine Corporation, filed an Application for Certification (AFC) with the 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. **PROJECT DESCRIPTION Figure 1** depicts the regional setting of the property.

In order to reliably connect the EAEC to the California Grid the proposed power plant would require:

1. A new substation, in this document referred to as the EAEC 230-kV switchyard (in Western's DFIS referred as Tracy East).
2. Two 0.5 mile double circuit 230-kV lines to intercept the existing Tracy-Westley 230-kV double circuit line (currently operating in a single circuit configuration).
3. Adding bays 13 & 14, with a double bus double breaker configuration, in the existing 230-kV Tracy Substation.
4. Converting the existing bays 1 through 12 in the existing 230-kV Tracy Substation to a double bus double breaker configuration.

New electrical equipment would also be installed within the existing boundaries of the Tracy and Westley Substations.

Natural gas for the facility would be delivered via approximately 1.8 miles of new 20-inch pipeline that would connect to Pacific Gas and Electric's (PG&E) existing gas pipeline. From the project site, the pipeline would run south along Mountain House Road, turning west at Kelso Road, and then south along the eastern side of the Delta Mendota Canal to the PG&E main line.

The applicant plans to supply the plant's cooling and process water requirements (averaging about 4,600 acre-feet per year) 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, offsetting raw water use. Note that staff is recommending that the applicant be required to eventually serve the project with 100% recycled water.

The project as proposed includes a zero-liquid discharge system designed to eliminate off-site disposal of wastewater. This represents a change from the original proposal to use evaporation ponds. Using the zero-liquid discharge system, 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. Oxides of nitrogen (NO_x) emissions will be controlled using a combination of low NO_x 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 applicant has proposed to minimize the emissions of NO_x 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 Final Determination of Compliance from the Bay Area Air Quality Management District is requiring that the applicant reduce the emissions to 2 ppm for NO_x, 4 ppm for CO, and 5 ppm for NH3.

The project is estimated to have a capital cost of between $400 and $500 million. The applicant plans to begin construction in 2003 and complete construction in 2005. 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.

The applicant has a contract with the California Department of Water Resources to provide power to the state.

PUBLIC AND AGENCY COORDINATION

In preparing the FSA/EA, Energy Commission and Western staff conducted several publicly noticed joint workshops. These workshops served not only to allow discussion between staff and the applicant, but also to hear from intervenors, interested agencies, and members of the public. One of the public meetings was a NEPA scoping meeting held in Livermore, California on November 14, 2001. “Scoping” provides anyone 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 has coordinated directly with relevant local, state and federal agencies, such as the California Independent System Operator (Cal-ISO), Bay Area Air Quality Management District (BAAQMD), U.S. Fish and Wildlife Service (USFWS), California Department of Fish and Game (CDFG), and the Central Valley Regional Water Quality Control Board. Further, Western has consulted with the U.S. Fish and Wildlife Service and the Native American Heritage Commission, and will complete consultation with the State Historic Preservation Office under its obligations for the National Historic Preservation Act before issuing a FONSI or, if an EIS is required, a Record Of Decision. Western has met its obligations under the Endangered Species Act and will continue nation-to-nation consultations with interested Native Americans.

Written comments received from members of the public, and letters from agencies that require some form of response, have been included in this FSA. Comments received from intervenors were considered in preparing this document.

STAFF’S ASSESSMENT

Each technical area section of the FSA/EA contains a discussion of impacts, and where appropriate, mitigation measures and conditions of certification. The FSA/EA 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 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 Visual Resources. Staff's analysis also indicates that the project can be made to conform with all LORS. 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	Impacts mitigated	Yes
Biological Resources	Impacts mitigated	Yes
Cultural Resources	Impacts mitigated	Yes
Power Plant Efficiency	None	N/A
Power Plant Reliability	None	N/A
Facility Design	N/A	Yes
Geology & Paleontology	Impacts mitigated	Yes
Hazardous Materials	Impacts mitigated	Yes
Land Use	Impacts mitigated	Yes
Noise	Impacts mitigated	Yes
Public Health	None	Yes
Socioeconomics	None	Yes
Traffic and Transportation	Impacts mitigated	Yes
Transmission Line Safety	None	Yes
Transmission System Engineering	Impacts mitigated	Yes
Visible Plumes	None	Yes
Visual Resources	Significant unmitigable impact	Yes
Waste Management	None	Yes
Water and Soils	Impacts mitigated	Yes
Worker Safety	None	Yes

Summarized below are staff's conclusions regarding a few of the technical areas that have been difficult to resolve: air quality, biological resources, hazardous materials, land use, noise, soil and water resources, and visual resources.

Air Quality

The EAEC as proposed has the potential to create significant impacts to local and regional air quality. Staff found that the project's emissions of oxides of nitrogen (NOx) and volatile organic compounds (VOC) have the potential to cause significant impacts relative to the state and federal 1-hour ozone air quality standards. Further, the project's emissions have the potential to cause significant impacts relative to the state 24-hour PM10 (particulate matter less than 10 microns in diameter) air quality standard. The project would also contribute to existing violations of the recently promulgated federal 8-hour ozone and 24-hour PM2.5 standards. However, the significance of these contributions is uncertain because the monitoring and attainment designations have not been completed.

The proposed location for the EAEC is in Alameda County and within the jurisdictional boundaries of the Bay Area Air Quality Management District (BAAQMD), but very near the border with San Joaquin County and the San Joaquin Valley Air Pollution Control District (SJVAPCD). Because the proposed site is east of the Altamont pass, the project's emissions would directly affect air quality in the SJVAPCD.

Under BAAQMD rules, the project applicant must offset air quality emissions, and can accomplish this by purchasing emission reduction credits (ERCs) anywhere within the BAAQMD territory. The applicant has satisfied BAAQMD offset requirements by purchasing Bay Area Emission Reduction Credits (ERCs) far to the west of the project site and of the Altamont Pass, where the offsets would result in only a small reduction of pollution transport into the area impacted by the project. Staff has determined that these ERCs are inadequate to fully mitigate the location and magnitude of local air quality impacts that would be caused by the project.

The applicant put forth a proposal designed to provide air quality benefits to offset the residual air quality impacts identified by staff. Staff evaluated this proposal and found that the proposal would be insufficient, both in terms of the tons of air pollution reduced, and in the specificity and enforceability of the measures proposed. Staff has identified two ways in which the applicant can fully mitigate the project's local air quality impacts. The first option, and staff's preferred method, would be for the applicant to implement specific local air quality improvement programs to create actual emission reductions. In devising this mitigation option, staff incorporated some of the elements of the applicant's "consensus" proposal into an air quality improvement program that can fully mitigate the project's local air quality impacts. The second option would be for the applicant to purchase ERCs from the SJVAPCD in quantities sufficient to offset staff's identified residual impacts. Staff would prefer that all feasible actual emission reduction scenarios be explored first, and that when those scenarios are exhausted, then any remaining emissions shortfall be met through the acquisition of ERCs from the SJVAPCD offset bank.

The project as proposed does not comply with the Bay Area District's Best Available Control Technology (BACT) requirements for NOx and CO emissions, and does not meet U.S. Environmental Protection Agency and California Air Resources Board guidelines for NH_3 emissions. However, the Bay Area District's conditions, which are contained in staff's proposed conditions of certification, will require the project to meet the District's BACT requirements. With full implementation of staff's proposed conditions of certification, the project will meet this and all other applicable LORS.

Biological Resources

The project area is part of a critical habitat pinch-point for the northern satellite population of the San Joaquin kit fox, a Federal and State listed species. Habitat mitigation that compensates for habitat loss and protects local habitats has been under review by staff in consultation with CDFG and USFWS. The applicant has proposed to mitigate for significant adverse impacts to listed species by purchasing mitigation habitat. Specifically, the applicant proposes to place a conservation easement on the Gomes Farms property, a 151-acre parcel that lies approximately one mile west of the EAEC project site. The applicant would further prepare a management plan, and establish an endowment to manage the land in perpetuity based upon a Property Analysis Report (PAR). The PAR will be conducted through the Center for Natural Lands Management (CNLM). The mitigation land would be managed by a qualified third party natural land management organization approved by Energy Commission staff, USFWS, CDFG, and Western.

While earlier versions of landscaping plans were found to create unacceptable biological impacts, the most recent landscaping plan proposed by the applicant was deemed adequate by the CDFG and USFWS. In contrast to the original landscaping plan, the applicant's final plan would minimize the use of large trees, limit the extent of landscaping within the project footprint, provide a substantial number of native plant species, and maintain a ground clearance of 3 feet for all vegetation. Staff concurs with the position of CDFG and USFWS, that the area within which the EAEC is located in a critical habitat pinch-point for the San Joaquin kit fox. Further degradation in habitat quality and quantity (including connectivity) from additional landscaping, would cause significant adverse impacts to the kit fox population. Though staff would prefer no landscaping around the project from the perspective of protecting the kit fox from predation and habitat degradation, the April 3, 2002 landscaping plan, combined with the applicant's proposed management of the landscaping, would minimize impacts. Staff has proposed conditions of certification that would mitigate all biological impacts to less than significant, and has further proposed conditions that, when fully implemented, would allow the project to conform to all biological resource-related LORS.

Hazardous Materials

Anhydrous ammonia and natural gas are the only hazardous materials proposed for use at the power plant that may pose a risk of off-site impacts. Large amounts of anhydrous ammonia would be used in controlling the emission of oxides of nitrogen (NO_x) from the combustion of natural gas in the facility. The applicant has proposed state-of-the-art engineering controls for the containment of anhydrous ammonia, and staff has found that these controls, combined with the applicant's proposed administrative controls, will prevent off-site consequences should there be an accidental spill.

Staff also evaluated the risks associated with the transportation of anhydrous ammonia to the site. The anhydrous ammonia would be transported to the facility via U.S. Department of Transportation-certified tanker truck. While the risk associated with transportation of anhydrous ammonia is very low and well within accepted norms, as discussed in the Hazardous Materials Management section of this FSA, it is readily feasible to use aqueous ammonia. However, staff found that aqueous ammonia provided little if any risk reduction to in-route populations. Therefore in the absence of significant risk from use of anhydrous ammonia at this proposed facility, staff found no basis for requiring use of aqueous ammonia based on transport risks.

Anhydrous ammonia has been identified by the U.S. Environmental Protection Agency (U.S. EPA) as a hazardous material for which special site security measures must be developed and implemented to ensure that unauthorized access is prevented. In order to ensure that this facility or a shipment of anhydrous ammonia to this facility is not the target of unauthorized access, staff's proposed General Condition of Certification on Construction and Operations Security Plan COM-8 will require the project owner to prepare a Vulnerability Assessment and implement Site Security measures consistent with the U.S. EPA requirements.

Staff's evaluation of the proposed project (with staff's proposed mitigation measures) indicates that hazardous materials use will not pose a significant risk of impacts on the public. Furthermore, with adoption of staff's proposed conditions of certification, the proposed project will comply with all applicable LORS.

Land Use

The project site is located on land that is zoned as large parcel agricultural. If not for the Energy Commission's "in-lieu of" status, the project would be required to obtain a conditional use permit from Alameda County, which in turn would require that the County make certain findings. Staff has received the conditional use permit findings from Alameda County. 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 East County Area Plan (ECAP), as amended by Measure D, is unclear. Although staff does not completely agree with the conclusions of the County, such conclusions are plausible and staff therefore defers to the County's interpretation of their own guidelines, standards, policies and conclusions that the EAEC is a consistent and allowed use.

The project's construction would result in the conversion of 40 acres from an agricultural use to a non-agricultural use and would 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 Association of Bay Area Governments (ABAG)'s Preservation of Agricultural Resources 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 including the contribution of funds to Alameda County for a 1:1 purchase of prime agricultural land for permanent farming use and/or easement purchases. Staff supports the County's successful effort to reach a mitigation agreement with the applicant regarding the conversion and loss of productive agricultural land, which is a potentially significant impact. After reviewing the final agreement, staff concludes that the payment of the $1 million fee agreed upon in the Farmlands Mitigation Agreement, in conjunction with Condition of Certification LAND-7, will mitigate the impacts of this project to a less than significant level.

Noise

The proposed project could result in a substantial permanent increase in ambient noise levels at sensitive receptors, which may be considered a significant impact. The local noise environments in rural areas may be very quiet, with few discernable ambient noise sources. A power plant will introduce a new noise source with a distinctive acoustical character, quite different from typical ambient noise. In rural areas, the increases in ambient noise levels at sensitive receptors due to power plant operations may be relatively large, depending upon plant design, distance to the sensitive receptors, and whether other structures, topography, or noise sources affect power plant sound transmission. In the case of the proposed project, achieving power plant noise levels that ensure there will be no substantial increase in ambient noise levels would be problematic because homes on nearby agricultural parcels, the Livermore Yacht Club, and one school are located within about 1.5 miles from the plant site, and ambient noise levels are relatively low (well below LORS standards). If constructed as the applicant has proposed, the project's noise level at the nearest sensitive receptors would represent an increase of up to 13 dBA over the nighttime ambient background noise levels. Such increases in background noise levels would profoundly alter the noise regime in the project vicinity, and would cause a significant impact. To mitigate this impact, staff is proposing a condition of certification that would require the applicant to reduce the plant's noise output measured at the nearest residence, to a level that would only slightly increase ambient nighttime noise levels. If this and all other recommended Conditions of Certification are implemented, impacts will be less than significant and the project, if built, would comply with all applicable LORS.

Soil and Water Resources

The applicant has proposed to supply the project's non-potable water needs with fresh inland (raw) water. 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, offsetting raw water use. However, the applicant as yet has not made any firm commitments for this recycled water. While staff has established the willingness of Mountain House to commit all recycled water it produces for use at EAEC, the applicant has conditioned its willingness to implement use of recycled water on whether it becomes available under terms and conditions solely acceptable to itself. For the purposes of the Energy Commission's analysis of the AFC, staff's analysis considered the effects of both cases: assuming the plant would rely solely on raw water, and assuming the plant would fully utilize recycled water as it becomes available from Mountain House.

Staff has determined that EAEC's proposed use of high quality fresh inland water for cooling, process water, and other non-potable uses, when recycled water is available, would constitute a significant impact. Absent the maximum implementation of recycled water use by EAEC, staff believes the sole use of fresh water by the project for non-potable needs could diminish local water supply, potentially depriving BBID's other customers of fresh water or resulting in inadequate supplies to the EAEC project itself. Staff believes that potentially significant adverse cumulative impacts to other fresh water users (i.e., residential and agriculture) could result if EAEC does not maximize its use of recycled water for cooling and other non-potable requirements. The Mountain House Community Services District has committed to supply all of its recycled water for use by EAEC.

The use of reclaimed water for cooling is well proven and could serve 100 percent of the project's non-potable water demands prior to 2020. Several sources of recycled water suitable for meeting EAEC's non-potable requirements are being developed in the area and will be available by as early as 2003. Staff also has concluded that recycling of the storm water to the cooling tower basin is a reasonable and economic means to conserve water. Staff's proposed conditions of certification require that the project utilize recycled water for all of its non-potable operational requirements as soon as possible, but no later than January 1, 2020.

With full implementation of staff's proposed conditions of certification, the proposed EAEC project will comply with applicable LORS, be consistent with established state policy regarding the conservation of fresh water supplies, and avoid significant impacts to other fresh water users.

Visual Resources

Although the proposed power plant facility would be located near transmission lines and a substation, staff concludes that the facility would be inconsistent with the existing rural character of the general area. Furthermore, the proposed facility 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 had the potential to mitigate the visual impacts of the proposed project. However, biology staff of the Energy Commission, CDFG, and USFWS were concerned about potential biological impacts of the proposed landscaping. Although a landscaping plan has been developed that was deemed to be adequate by the CDFG and the USFWS, the plan does not adequately reduce the visual impact of the proposed project. Staff therefore concludes that the project would result in unmitigable significant impacts to visual resources.

Staff concluded that the proposed project structures would be inconsistent or partially inconsistent with seven of Alameda County's LORS, two of which would constitute an adverse but not significant impact, another two of which could be mitigated to a level of less than significant, and two more that would constitute a significant, unmitigable impact. The Alameda County Planning Department, however, has found that the project would be consistent with all of the county's applicable LORS. Consistent with California Code of Regulations, title 20, section 1714.5(b), staff gives due deference to Alameda County's determination that the project complies with the visual resources LORS under its jurisdiction. Therefore, staff's determination is that the project is consistent with all applicable LORS.

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

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.

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

Staff has evaluated the potential for unmitigated or disproportionate adverse impacts on EJ populations in the vicinity of the proposed EAEC, and found none.

Project Alternatives

The purpose of the 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. In doing so, it is important to note that the Energy Commission's authority is limited to either approving or denying the EAEC at the site proposed by Calpine. The Energy Commission does not have the authority to approve an alternative or require Calpine to move the proposed project to another location, even if it identifies an alternative site that meets the project objectives and avoids or substantially lessens one or more of the significant effects of the project. If Calpine were to decide to build a power plant at another site, a new Application for Certification would need to be filed and the review process would begin anew for that site.

Staff's alternatives analysis describes a range of reasonable alternatives to the proposed project, or to the location of the project, that could feasibly attain the basic project objectives but would avoid or substantially lessen any of the significant effects of the project. The assessment also evaluates the comparative advantages and disadvantages of the various alternatives in less detail than the analysis of the project, but in a manner sufficient to inform the decision making process.

Staff identified and reviewed 4 alternative sites, all of which have their own set of unique issues and potential impacts. Overall, the four site alternatives considered in this section offer some advantages and disadvantages in comparison to the proposed project. However, none of the alternative sites appear to reduce the potentially significant adverse impacts of the project without causing additional potentially significant adverse impacts themselves.

One of the applicant's primary objectives for the project is to be online by 2005. The California Department of Water Resources (DWR) has a contract with the applicant to provide electricity from this facility. In order to satisfy the contract, the applicant must receive Energy Commission certification by November 30, 2002 or 90 days thereafter. Staff believes both the contract and the projected online date are key elements that support the needed development of California's electricity supply. Implementation of an alternative site would require that the applicant submit a new AFC, including revised engineering and environmental analysis; this more rigorous AFC-level analysis of any of the alternative sites could reveal environmental impacts, non-conformity with laws, ordinances, regulations, and standards, or potential mitigation requirements that were not identified during the more general alternatives analysis presented herein. None of the alternatives would allow the applicant to meet the DWR contract requirements or the objective of being online by 2005.

For purposes of the NEPA process, Western has determined that none of the siting alternatives analyzed under the staff alternatives analysis are consistent with Western's purposes and need to provide non-discriminatory open transmission line access.

CONCLUSION AND RECOMMENDATIONS

If the Energy Commission determines that a proposed project would result in unmitigated significant adverse impacts to public health and safety, the environment, or the electric transmission system, the Commission must make findings of overriding consideration in order to certify the project. In particular, the Energy Commission must specifically find that: (1) specific considerations make infeasible the mitigation measures or project alternatives identified in the proceeding; and (2) that the benefits of the project outweigh the unavoidable significant adverse environmental effects that may be caused by the construction and operation of the facility (Cal. Code Regs., tit. 20, § 1755(d)).

Pursuant to item (1) above, staff has found a significant adverse impact to visual resources for which mitigation is infeasible because of a conflicting biological concern. To mitigate for the impacts to visual resources would require the planting of substantial numbers of trees for screening, which would degrade the quality of the habitat for San Joaquin kit fox, and increase the potential for predation on this species. This would cause a significant biological impact. Staff and applicant worked with USFWS and CDFG, and put considerable time and effort into the exploration of landscaping designs that could satisfy both visual and biological concerns without causing significant impacts to either. However, because this site is considered to be a critical habitat pinch-point for kit fox, there is no room for altering the landscaping plan without causing significant impacts to biological resources. After considering all of the options, and the fact that the San Joaquin kit fox is a Federal and State listed species, staff concluded that the importance of avoiding additional impacts to this endangered species made the visual resources mitigation infeasible.

As described above, staff has also determined that none of the alternatives would allow the applicant to meet the DWR contract requirements or the objective of being online by 2005. In addition, none of the alternative sites analyzed by staff appear to reduce the potentially significant adverse impacts of the project without causing additional potentially significant impacts themselves. Therefore, it is staff's position that none of these project alternatives are feasible.

Pursuant to item (2) above, Energy Commission staff concludes that the project's potential electric system benefits substantially outweigh the projects potential impacts to visual resources. According to the Energy Commission's *2002-2012 Electricity Outlook Report* (February 2002), the supply market in 2005 and beyond is of concern.

To prevent tight supplies from materializing in the year 2005 and beyond, the State of California has been working on modifications to the electricity market, pursuing upgrades in the transmission system (most notably Path 15 upgrades), developing energy conservation programs (e.g., the “Flex Your Power” campaign and the “20/20 Program”), and has entered into a series of long-term contracts. One of these contracts is with Calpine for the East Altamont Energy Center to provide long-term supplies to California's electric system at fixed contract prices. This contract and project is a small but critical part of the overall strategy to provide California with an adequate supply of electricity for economic growth and prosperity, stable electric prices, and a reliable electric system for the future (2005 and beyond).

Because the State of California is relying on the electrical output from this power plant, staff recommends that the Commission approve the East Altamont Energy Center Application for Certification, including staff’s proposed conditions of certification, with overriding considerations.

INTRODUCTION

PURPOSE OF THIS REPORT

The Final Staff Assessment (FSA)/ Environmental Assessment (EA) presents the California Energy Commission and the 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 FSA/EA 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 FSA/EA 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 FSA/EA are based upon information from:

- the Application for Certification (AFC);
- subsequent submittals;

- responses to data requests;
- supplementary information from local and state agencies and interested individuals;
- existing documents and publications; and
- 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 FSA/EA presents conclusions and proposed conditions of certification that apply to the design, construction, operation and closure of the proposed facility.

The analyses contained in this FSA/EA were prepared in accordance with:

- Public Resources Code sections 25500 et seq.;
- the California Code of Regulations, title 20, section 12001 et seq.;
- the California Environmental Quality Act (Pub. Resources Code, § 21000 et seq.) and its guidelines (Cal. Code Regs, tit. 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).

ORGANIZATION OF THE STAFF ASSESSMENT

Following the Response to Public and Agency Comments and Project Description, this FSA/EA contains staff’s environmental, engineering, and public health and safety analysis of the proposed project for 20 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, visible plumes, 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 20 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 Preliminary Staff Assessment (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 conducts 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 refines the analysis, corrects any errors, and finalizes conditions of certification. Responses to written comments on the PSA are incorporated into the 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 FSA 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 FSA.

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 Western's 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 Western's 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 document serves as Western's Final EA, which serves to support a Western determination on whether or not to prepare an Environmental Impact Statement (EIS). For purposes of the NEPA process, Western will determine the significance of impacts in a separate determination issued after the Final EA. Western will consider the Final EA and subsequent public, agency and tribal comments on the Final EA in making this determination. If Western determines there are no significant impacts it will issue a Finding of No Significant Impact (FONSI). A preliminary version of the FONSI will be made available for public review for at least 30 days. Publishing a final FONSI will complete the assessment portion of the federal environmental process. If Western determines there are significant impacts, it will publish a notice of intent to prepare an EIS in the Federal Register and distribute copies to the project's mailing list. An EIS will then be developed using the results of the Final EA and other analyses, and issued for public comment. If an EIS is needed, Western will independently publish a final EIS and Record of Decision before completing the federal environmental process.

PUBLIC AND AGENCY COORDINATION

In preparing the FSA/EA, Energy Commission and Western staff conducted several publicly noticed joint workshops. These workshops served not only to allow discussion between staff and the applicant, but also to hear from intervenors, interested agencies, and members of the public. One of the public meetings was a NEPA scoping meeting held in Livermore, California on November 14, 2001. "Scoping" provides anyone 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 has consulted with the U.S. Fish and Wildlife Service and the Native American Heritage Commission, and will complete consultation with the State Historic Preservation Office under its obligations for the National Historic Preservation Act before issuing a FONSI or, if an EIS is required, a Record Of Decision. Western has met its obligations under the Endangered Species Act and will continue nation-to-nation consultations with interested Native Americans.

Written comments received from members of the public, and letters from agencies that require some form of response, have been included in this FSA/EA. The **Response to Comments** chapter of this FSA/EA contains an index of all comments received and a listing of where these comments are addressed.

POWER PLANT EFFICIENCY

Testimony of Shahab Khoshmashrab and 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 an approximate value based upon preliminary design information and generating equipment manufacturers' projected performance with the plant operating at full load with maximum HRSG duct firing on a cold day.) The AFC is not specific as to whether the plant is 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 (at average ambient conditions), with an additional 238 to 269 MW of peaking capacity (depending on the ambient conditions) provided by large duct burners and a large steam turbine generator (EAEC 2001hh). The applicant envisions operating the plant up to 8,760 hours per year with the incremental peaking capacity operated for up to 5,080 hours per year (EAEC 2002a).

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 (average ambient conditions with 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 (average ambient conditions), arranged in a three-on-one combined cycle train, totaling approximately 1,090 MW at average ambient conditions. 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 1.8-mile natural gas pipeline (EAEC 2001a, AFC §§ 1.1, 2.1, 2.4.3, 6.0, 6.1, 10.2.1; EAEC 2002n, p. 2).

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 (up to 269 MW) at an incremental efficiency of 41 to 42 percent LHV, yielding a full load (up to 1,090 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; EAEC 2002n, p. 2). 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 augmented by duct burners. In a combined cycle system, 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.

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.

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.

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 fuel efficiency of the plant with the duct burners operating will be 51.5 to 52 percent (LHV), representing a drop in fuel efficiency of four percentage points.

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 San Joaquin Valley Energy Center (formerly 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.

Alternative to Duct Burners

The operating flexibility afforded by duct burning in the EAEC could alternatively be supplied by a three-on-one non-duct fired combined cycle plant of 820 MW, plus several smaller peaking plants generating 267 MW, totaling 1,087 MW. The most effective means of achieving this peaking capacity would be with six GE LM6000 Enhanced SPRINT gas turbine generators, rated at 48 MW each for a total of 288 MW. The LM6000 SPRINT offers the best fuel efficiency and air emissions performance of any such machine available today. The claimed efficiency of these machines is 39.6 percent LHV (GTW 2000).

If the EAEC were operated without duct burning, and six LM6000 SPRINT peakers were operated in conjunction to provide 1,108 MW total, the resulting net fuel efficiency would be 51 percent LHV. This does not quite equal the 51.5 to 52 percent range projected for the EAEC with duct burning, and offers no advantage in fuel efficiency or air emissions performance. The LM6000 peaker alternative would also involve considerable additional expense and complication in building, operating and maintaining the facility.

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).

[1] International Standards Organization standard conditions are 59°F (15°C), 60 percent relative humidity, and sea level pressure (29.92 in. Hg).

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, resulting in a slightly lower efficiency and somewhat lower combined cycle output, 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).

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. Western has determined that none of these generating technology alternatives, other than the proposed action, are consistent with Western's purposes and need.

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 fuel-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.

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,[2] and power output on a hot day, under full peaking output, may drop about 46.4 MW (EAEC 2001p). While this is a measurable degradation in power output and fuel efficiency, staff believes that it could be justified by the significant savings in water consumption. (Note that the applicant estimates potential revenue losses approaching $10 million per year if dry cooling is employed (EAEC 2002a). Staff does not purport to address the economics of a switch to dry cooling.) From an efficiency standpoint, then, staff regards the use of dry cooling as a justifiable modification. Western, on the other hand, has determined that no condenser cooling alternatives, other than that proposed, are consistent with Western's purposes and need.

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. There are no feasible 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 (now FPL) 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

[2] This is the figure estimated for the Sutter Power Project (97-AFC-2).

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 up to 269 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.

REFERENCES

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EAEC (East Altamont Energy Center, LLC.). 2001 p. Data Adequacy Response Set #2C, dated September 14, 2001.

EAEC (East Altamont Energy Center, LLC.). 2001 ee. East Altamont Energy Center Informal Data Response Set #2, dated October 12, 2001.

EAEC (East Altamont Energy Center, LLC.). 2001 hh. East Altamont Energy Center Informal Data Requests and Responses Set #3 (01-AFC-4), dated November 21, 2001.

EAEC (East Altamont Energy Center, LLC.). 2002 a. East Altamont Energy Center PSA Comments Set #1 (01-AFC-4), dated January 14, 2002.

EAEC (California Energy Center) 2002 n. Supplement C to the East Altamont Energy Center AFC. Dated February 6, 2002 and docketed February 6, 2002.

GTW (Gas Turbine World). 1999 b. Gas Turbine World 1999-2000 Performance Specs, volume 19. December 1999.

GTW (Gas Turbine World). 2000. Gas Turbine World 2000-2001 Handbook, volume 21, pages 68-89.

GTW (Gas Turbine World). 2001. *Gas Turbine World*, May-June 2001.

Power (Power Magazine). 1994. “Operating and maintaining IPP/cogen facilities,” Power, September 1994, p. 14.

RESPONSE TO PUBLIC AND AGENCY COMMENTS

Below is an index of comments received from interested members of the public and governmental agencies that contained questions on staff's review of the East Altamont Energy Center (EAEC) Application for Certification or other comments that require some form of response. A few of the questions or comments are answered in this chapter, 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 comment.

Also included are responses to comments received during the California Energy Commission / Western Area Power Administration joint scoping meeting, held November 14, 2001.

AGENCY COMMENTS ON THE PSA

ALAMEDA COUNTY COMMUNITY DEVELOPMENT AGENCY

On August 15 and October 4, 2001, staff received letters from the Alameda County Community Development Agency that provided comments from various County departments regarding the proposed EAEC. These letters contained comments and recommended conditions for certification that are addressed in the following sections of this document:

LAND USE

VISUAL RESOURCES

WORKER SAFETY AND FIRE PROTECTION

TRAFFIC AND TRANSPORTATION

SOIL AND WATER RESOURCES

The Community Development Agency, in conjunction with the County's department of Environmental Health Services, later submitted a letter on December 17, 2001, with comments on the noise element of the PSA. These comments are addressed in NOISE AND VIBRATION.

ALAMEDA COUNTY FIRE DEPARTMENT

On January 30, 2002, the Alameda County Fire Department wrote a letter to staff regarding Alameda County's jurisdiction over the site where the EAEC is proposed to be located. These comments are addressed in WORKER SAFETY AND FIRE PROTECTION.

ALAMEDA COUNTY PUBLIC WORKS AGENCY

The Alameda County Public Works Agency submitted a letter to staff on May 8, 2002, with concerns and suggested conditions of certification concerning roadways. These comments are addressed in the TRAFFIC AND TRANSPORTATION.

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.

CALIFORNIA DEPARTMENT OF INDUSTRIAL RELATIONS DIVISION OF OCCUPATIONAL SAFETY AND HEALTH

The Department of Industrial Relations submitted a letter to staff on September 6, 2001, with comments about safety and health programs for the proposed EAEC. These comments are addressed in the WORKER SAFETY AND FIRE PROTECTION.

CALIFORNIA DEPARTMENT OF WATER RESOURCES

On May 14, 2001, the Department of Water Resources provided comments regarding the potential effects of increased fault currents from the EAEC on their facilities' electrical systems and equipment. These comments are addressed in TRANSMISSION SYSTEM ENGINEERING.

CITY OF TRACY FIRE DEPARTMENT

The City of Tracy Fire Department submitted comments to the Alameda County Fire Department with a carbon copy to staff, on June 10, 2002, with concerns regarding their mutual aid agreement with Alameda County. Staff has addressed these concerns as part of their analysis of WORKER SAFETY AND FIRE PROTECTION.

CITY OF TRACY PUBLIC WORKS DEPARTMENT

On December 20, 2001, the City of Tracy Public Works Department submitted comments on the PSA regarding the availability of recycled water from their wastewater treatment plant. These comments are addressed in SOIL AND WATER RESOURCES.

CONTRA COSTA WATER DISTRICT

On January 18, 2002, the Contra Costa Water District provided comments on the Preliminary Staff Assessment / Preliminary Environmental Assessment (PSA/PEA) concerning water impacts that are addressed in the SOIL AND WATER RESOURCES chapter of this document.

DEPARTMENT OF TOXIC SUBSTANCES CONTROL

The Department of Toxic Substances Control submitted comments dated October 16, 2001 regarding the Application for Certification in relation to the Site Mitigation Plan. These comments are addressed in the WASTE section of this document.

EAST BAY REGIONAL PARK DISTRICT

On January 14, 2002, the East Bay Regional Park District submitted comments on the Preliminary Staff Assessment expressing concerns that the project not interfere with the District's Master Plan to develop future trails in the vicinity of the proposed power plant. These comments are addressed in LAND USE.

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.

MOUNTAIN HOUSE COMMUNITY SERVICES DISTRICT

On December 14, 2001, the Mountain House Community Services District submitted comments regarding fire protection for the EAEC. These comments are addressed in WORKER SAFETY AND FIRE PROTECTION.

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, 2001 opposing the EAEC. The resolution cites concerns regarding air pollution, fumes and potential transportation hazards arising from the plant's proposed use of ammonia, an evacuation plan, and the plant's use of fresh water. A corrected copy of the resolution was submitted in a letter dated July 11, 2001. Staff met with Supervisor Bedford on May 9, 2002 to further explore these concerns. These comments are addressed in AIR QUALITY, HAZARDOUS MATERIALS, and SOIL AND WATER RESOURCES.

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 believes that we have adequately addressed these topics in AIR QUALITY, HAZARDOUS MATERIALS, and NOISE. Because the concerns are general in nature, however, there is no specific response given in these chapters.

SAN JOAQUIN COUNTY DEPARTMENT OF PUBLIC WORKS

On March 14, 2002, the San Joaquin County Department of Public Works provided comments on the PSA/PEA regarding potential impacts to roadways. These comments are addressed in TRAFFIC AND TRANSPORTATION.

TOWN OF DISCOVERY BAY

The General Manager of the Town of Discovery Bay wrote a letter to staff on November 14, 2001 providing background information on their wastewater treatment plant expansion plans, and proposing to serve recycled water to the East Altamont Energy Center. These comments are addressed in SOIL & WATER RESOURCES.

PUBLIC COMMENTS (NON-INTERVENORS)

MATT SULLIVAN

MS-1 *My name is Matt Sullivan, and I am a resident of Pleasanton, California. I am also a member of the Pleasanton Planning Commission, as well as the community Energy Advisory Group appointed by the City Council. I have* *reviewed the Preliminary Staff Assessment (PSA) for the East Altamont Energy Center proposed by Calpine, and offer the following comments and questions.*

Based on my review of the PSA, there appears to be several serious issues and impacts from the building of this plant. The PSA has pointed out potential problems with air quality, biological resources, soil and water resources, land use, and the transmission system. However, as the CEC has pointed out, the Applicant has not submitted the required information nor has taken the necessary steps to fully evaluate these impacts. How can the public weigh in if all the information has not been provided? I would request that there be an updated PSA and another round of public hearings before the CEC prepares the Final Staff Assessment.

Response: Because of this concern, staff held several workshops in between the PSA and the FSA, to allow members of the public to follow these issues as they evolved. After the FSA is released there will be additional opportunities for public comment at hearings that will be held in October of this year.

Other specific items and questions I would like to raise are as follows:

MS-2 *With this plant the state is again trying to solve the "energy crises" by building large central plants and transmitting power over long distances to reach the end user. This results in severe environmental problems in terms of land use, air quality and water impacts, as well as the impacts caused by building/expanding transmission lines – not too mention the electrical loses from the transmission lines. We need a new model that is based on Distributed Generation, Renewable Energy and Demand Side Management to meet our energy needs.*

Response: The Energy Commission in fact has programs to promote research and development, or address commercialization barriers, for distributed generation and renewable energy technologies, as well as programs to promote Demand Side Management. However, the Energy Commission is also required to analyze power plant proposals on their face. We compare the project to other technologies in our alternatives analysis, but we cannot redefine the project or require the developer to change their project.

MS-3 *This plant will use 4,600 acre-feet of water per year. In a state like California, this is an unconscionable use of water when viable alternatives exist.*
(See SOIL & WATER RESOURCES)

MS-4 *How will the crystallized brine from the water treatment plant be disposed of? How will cooling tower blowdown and other wastewater streams be dealt with?*
(See SOIL & WATER RESOURCES)

MS-5 *The cost estimate for this plant is $500 million. Calpine has been experiencing financial problems of late. Is there any requirement for a bond from the developer to allow the plant to be completed (or dismantled) in case Calpine goes bankrupt or pulls out halfway through construction?*

Response: You raise a good point, but as of yet we do not have any requirements for applicants to be bonded. We do, however, require closure plans as a condition of certification.

MS-6 *The PSA has pointed out that Calpine is not proposing BACT air emissions controls for the plant. Again, unconscionable in an area with severe air quality problems to begin with. In addition to air pollution impacts on the San Joaquin Valley, this will add to the air pollution problems in the downwind Sierra Nevada Mountain region.*
(See AIR QUALITY)

MS-7 *The fact that the flawed deregulation bill of 1998, AB1890, precludes the consideration of new plant need by the Energy Commission in the approval process is absurd. This first thing we need in developing a sane energy policy for California is to determine real needs and how they best can be addressed.*

Response: You have expressed a valid concern, but this would require a change in legislation, which is beyond the scope of staff's analysis.

MS-8 *I believe that the evaluation of Project Alternatives performed in the PSA was superficial and totally inadequate. No data, analysis or examples were presented to justify the conclusions, especially in regard to Distributed Resources or Demand Side Management. This is typical of a report that seems to want to justify the building of a plant at all costs, and was similar to the sham of an evaluation that PG&E performed for the Tri-Valley Transmission Upgrade project. I will offer just a few examples of Demand-Side Management strategies that are being taken now locally can reduce the need for this project:*

1. *San Francisco just passed a $100 million revenue bond to finance the implementation of solar PV and wind generation installations, and comprehensive energy-efficiency measures. San Francisco estimates that they can provide 40 megawatts of new renewable power from this program*

2. *The City of Pleasanton has established an Energy Advisory Group, made of residents, business, and industry representatives, whose goal is to develop a comprehensive, sustainable energy strategy for the City. The group has already identified distributed generation, renewable energy and demand-side strategies that are expected to greatly reduce electric demand in the City, as well as reduced reliance of grid power.*

3. *For the past year and a half, Pleasanton has included comprehensive "Greenbuilding" and solar PV conditions in all new commercial and residential development approvals. This will further reduce the energy demand of the City and the need for grid-supplied power.*

4. *The City of Dublin is exploring options to build a locally owned and controlled 50MW power plant in the city, that would reinforce the grid and reduce the need for large, remote power plants such as the EAEC.*

5. *The Cities of Walnut Creek, Brentwood and San Ramon are preparing energy plans and strategies to implement a wide range of demand-side measures to save energy – which will again reduce the need for plants like the EAEC.*

These are just a few local examples of actions that are being taken locally that are viable alternatives – or at the very minimum – would reduce the need for large central plants such as the EAEC. The PSA has totally failed in its evaluation of such alternatives, especially if they are examined in the context of their potential positive impact of grid load reduction.

The PSA also states that renewable alternatives are not cost competitive with the EAEC. However, the total costs – including the environmental and social costs – are not examined in the analysis. Who will pay for the environmental impacts and increased health care costs that result from the plant? The taxpayers. Who will pay for the loss of property value of the adjacent neighbors, including those in the future Mountain House community? The property owners. Who will pay the increased food costs that result form diminishing prime farmland? The consumers. Who will pay the costs to upgrade the transmission and distribution systems that will be required to get this power to the end users? The ratepayers. These costs are not included in the analysis.

Developers – and generally the public agencies that approach such projects - call these costs "externals" and dismiss them from the analysis and comparison with other alternatives. This approach does not provide a fair comparison of alternatives.

Finally, the biggest cost to consumers will come from increasing the monopoly that a few large power providers have on the market. We saw this last year with the "gaming" of the supply market, and we are bound to see it again unless fundamental change in energy generation, transmission and use occur.

<u>Response:</u> The analysis of alternatives in the PSA (and in this FSA) is consistent with the requirements of CEQA, which does not require that alternatives be evaluated at the same level of detail as the proposed project. Conservation and Demand Side Management (DSM) are not evaluated as alternatives to the proposed project because the efforts to implement these programs are ongoing, and will continue regardless of whether this project is approved. Additionally, staff is prohibited from considering these measures as alternatives to a proposed project by Public Resources Code 25305(c).

Staff agrees that the types of local programs described in the comment are essential components of California's approach to providing an adequate energy supply. However, it remains to be seen whether the specific power plants mentioned (particularly the 50 MW power plant in Dublin and distributed generation in Pleasanton) will actually be implemented. Several 50 MW peaker plants were proposed in the Pleasanton and Livermore areas in 2000-2001, and all met with strong citizen opposition, resulting in the applicants being forced to withdraw their applications.

The City and County of San Francisco are more aggressively addressing their power needs, as acknowledged in the comment. The first San Francisco solar project to be implemented under the revenue bond program would provide 300-500 kilowatts of power for about $700,000 (consistent with the expectation contained in your letter that up to 40 MW could be generated under the $100 million bond issue, assuming that appropriate locations are found for the solar installations). Staff is not aware of similar projects underway in Alameda County, however.

Regarding the concerns about public health issues and loss of prime farmland, these potential impacts have been addressed in this FSA (see sections on PUBLIC HEALTH and LAND USE), and mitigation is recommended to reduce these impacts to less than significant levels.

SUSAN M. SARVEY

SMS-1 *I was on the GWF mitigation committee. We were able to get what our community needed. The pollution Control Board just rolled over without a look back for our health. Read our mitigation for yourself and see how much more relevant it was for our community and valley air. In the GWF case it came to light that my fire truck spends 30% of its response time in Alameda County and there is no fire protection for my home and the GWF Plant. This plant will only add more responsibility to our overburdened fire department and it will add more fire risk. We all know that fire is terrible for air quality. Safeway had to provide a fire truck when they came to Tracy and EAEC should have to do the same so my air, public health and safety are not put at greater risk. Calpine professes to have good intentions but at every turn they try to take the cheap way out and suppress public input and participation. Ask GWF (Doug Wheeler) this will not work in Tracy. We care about our health and safety and we are ready to do <u>whatever</u> it takes to protect it.*

(See WORKER SAFETY AND FIRE PROTECTION)

EDDIE GANDARILLA

EG-2 *Calpine will pollute our local area while the San Joaquin Valley Air District will send our mitigation money on Bakersfield. They already screwed us with the Tracy Peaker Plant. How many of these plants are we going to get? Offsetting their pollution with credits from industries shut down 10 years ago doesn't help no matter where the ERC's are located. The SJVAPCD is selling out Tracy once again.*

(See AIR QUALITY)

EMMA I. HALL

EIH-1 *I am offended that Calpine has reneged on their promise to mitigate the impact of their plant on the citizens of Tracy. They now propose to give the funds to the Pollution Control District. I do not trust the Pollution Control District to use the funds for our protection.*

Their actions on the GWF project proves my theory. Every indication from their efforts on this project show their poor judgment.

Response: Your comment has been noted. Please see AIR QUALITY for a response to your concerns.

PAUL SUNDBERG

PS-1 *It's ironic that the San Joaquin Valley Air Pollution Control District is asking for money to mitigate EAEC Pollution because the emission reduction credits are up to 60 miles away from the plant site. The ERC's provided by the SJVAPCD to mitigate the Tracy Peaker Plants emissions were predominately 200 miles away. The San Joaquin Pollution District will sell out the citizens of Tracy out just like they did in the Tracy Peaker Plant. They will probably spend the $965,000 to fix up their office in Fresno. I attended the EAEC Workshop in Tracy and found the District representative to be very arrogant. Didn't he realize that without the CEC staff the district would receive no mitigation. The only local mitigation we got from GWF was through our own citizens negotiating. Calpine is using the Pollution Control District to ruin any real local air quality mitigation that the CEC might force them to provide. They are just trying to avoid their obligation to offset their local emissions in the Tracy area. Deny them their license.*

(See AIR QUALITY)

IRENE K. SUNDBERG

IKS-1 *This is just mind provoking that this community should have to deal with the air pollution from the bay area and not have been included in mitigation. Our fire truck is gone 30% of the time to the Altamont Hills to assist on fires from Alameda County because Tracy is closer and can usually get there faster.*

Tracy should be at the table for mitigation as they formed a citizens group to mitigate with GWF, they should also mitigate East Altamont.

The acceptable mitigation would be a fire truck and station for all the power companies to share the cost in, as we wouldn't need this if we had no power companies breathing down our necks.

Tracy should have the right to mitigate these issues as we did with GWF. We want to mitigate these issues!

(See WORKER SAFETY AND FIRE PROTECTION)

PAULA R. BUENAVISTA

PRB-1 *I respectfully request that the California Energy Commission require the Calpine Company (East Altamont project) to mitigate all of its air quality credits in Tracy. Allowing this company to clean up other areas of the San Joaquin Valley will do absolutely nothing to clean the air in our local Tracy. Ground level ozone is becoming an increasing health hazard that our community is having to endure.*

Please enforce the strictest mitigation possible to this business. It is my request that in our current grade of poor air quality, labeled "extreme" by the U.S. Environmental Protection Agency, that this project be denied.

(See AIR QUALITY)

CYNTHIA B. JOHNSON

CBJ-1 *There is an article attached to this public comment form. It is an article regarding Asthma. Also "How smog chokes the valley."*

(See AIR QUALITY)

ANN K. JOHNSON

AKJ-1 *There is an article attached to this public comment form. It is an article entitled "…leaves locals gasping for air." (The first part of the title is cut off.)*

(See AIR QUALITY)

JON S. SNYDER

JSS-1 *There is an article attached to this public comment form. It is an article entitled "Breathless."*

(See AIR QUALITY)

CAROLE DOMINGUEZ

CD-1 *We need negotiation on our fire service needs. Our trucks respond to Altamont fires leaving our city at risk and without adequate coverage.*

(See WORKER SAFETY AND FIRE PROTECTION)

BETHANY G. HOOPER

BGH-1 *Tracy needs a fully equipped fire station and mitigation for air quality from East Altamont.*

The deaf should be included in public notification process of problems with these 3 plants coming on line in our area. Using a public warning system for the deaf and full website alert would allow the hearing impaired to be notified also.

(See WORKER SAFETY AND FIRE PROTECTION and HAZARDOUS MATERIALS)

JAMES M. HOOPER

JMH-1 *We want a fully equipped fire station that services the 3 electrical plants only. Tracy needs mitigation right with EAEC. I want TTY's in public services areas so the hearing impaired can be notified of emergencies.*

(See WORKER SAFETY AND FIRE PROTECTION)

CATHERINE H. HARITON

CHH-1 Fire protection needed. Another fire station is a necessity.

(See WORKER SAFETY AND FIRE PROTECTION)

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.

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 note of San Joaquin County's opposition to this power plant in Alameda County. Although the issues raised in the Resolution were general in nature, staff has tried to respond to these concerns within the staff analysis. 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: Yes, Calpine has entered into a contract to sell power from this plant, if certified, to the State of California. Please refer to the PROJECT DESCRIPTION for more information about this contract.

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 the remainder of our process, and provide comments on staff's analysis of the project, for the benefit of the Commissioners in making their final decision.

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.

G&MG-5 *I also have a concern about the bright lighting that will be at night on the country roads. When the Muso Olive plant added lighting to their plant off of Schulte and Mt. House Parkway, if you were driving south on Mt. House Parkway, at times the driver was blinded by these (I believe they were described as Cal Trans Lights) lights. Many times I was blinded by these lights and couldn't see the road. This also added brightness from the Safeway and Costco plants. There must have been complaints to the plant as they were adjusted, and they are not as blinding as before although they are still bright. I think the distance was about a mile or so.*

(See VISUAL RESOURCES)

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). We encourage you to participate by providing additional public comment at the upcoming evidentiary hearings.

SHELDON G. MOORE

SM-1 *This Calpine project would have been great 50 years ago, prior to energy, security and ecology concerns. The East Altamont Energy Center is a simplistic approach to a complex problem. Today, this project is ill advised because we have more knowledge and experience in the areas of energy efficiency, ecology and recently are learning the importance of National Security.*

A portion of our ranch was condemned 10 years ago under the pretext of separation of power transmission sources, for security reasons. With this East Altamont Energy Center plan, the reason for that condemnation is now bogus. The Calpine plan concentrates both generation and transmission of power to a very dangerous point. Sadly the reality of 911 will hang over this great nation for longer than we wish. We, as a nation, must operate our publicly used resources in a new way with maximum security being a top priority. The best plan today for both thermal efficiency and security is to disperse power plants. With the dispersal of power generation you can better use the thermal waste as you size the plant to local needs. There is no longer need for huge power transmission facilities. On site or close to site, gas fired generation can use the "waste," thermal energy to heat and cool structures. Energy is thus saved and a better environment is created.

Today, we must not repeat the mistakes of the past in the use of energy. Energy is a precious commodity and energy must be conserved. We do not need a quick but unwise fix today for our electrical problems. We must not waste tomorrow what we waste today.

Response: The Energy Commission in fact has programs to promote research and development and address commercialization barriers for distributed generation, and programs to promote energy efficiency. However, the Energy Commission is also required to analyze power plant proposals on their face. We compare the project to other technologies in our alternatives analysis, but we cannot redefine the project or require the developer to change their project.
Staff has evaluated this project for impacts to the transmission system, the environment, and public health, and has determined that all such impacts can be mitigated except for those to visual resources.

Regarding your concern about security, please see HAZARDOUS MATERIALS for a discussion of new security-related conditions.

SM-2 *The problem of noise pollution was not discussed. Since your meeting, I have discovered that Calpine has current noise pollution problems with smaller gas fired plants.*

Response: While your comments are not specific, the general topic of noise from the proposed facility was indeed analyzed and is presented in the NOISE AND VIBRATION section of this document.

SM-3 *The total sum of the pollution from this project is considerable and is still not precisely defined. The waste thermal energy is significant and will not be utilized to heat and cool homes or factories. Water use or waste is also great for the acres involved.*

I asked Mr. D. Crespo, Community Outreach Coordinator for East Altamont Energy Center for just one positive effect this project would have on our ranch. There is no positive effect, only disaster. I have lived here for 40 years and our ranch is less than one mile from the site and directly down wind the majority of the year. I am not in favor of putting my mega-pollution on my neighbors and I do not want my neighbor to put their mega-pollution on me. This is the Golden Rule. I take a very dim view of inverse condemnation, which is what the pacing of an 1,100 Megawatt gas fired plan as planned would be.

Response: Staff has not found any significant impacts to air quality that can't be mitigated. See staff's proposed conditions of certification in the AIR QUALITY section.

SM-4 *WAPA should reject this plan for security reasons. As a side issue, I feel it is urgent that WAPA improve security at their present switchyard. It appears to me that the 1994 switchyard upgrade completely ignored security required at that time. Today the ignored security must be addressed.*

Response: The proposed interconnection and the operation of Western's Tracy Substation are consistent with Western's current security requirements.

SM-5 *The Sierra Research documents appear to be junk data. Comments by the San Joaquin Valley Air Pollution Control District tend to confirm my thought.*

This proposed plant is just too big for the San Joaquin Valley Air Pollution Control District because as you well know the Valley in effect is a closed basin.
It appears that the air current patterns in the project proposal area are not understood by the experts. Where is the wind data?
(See AIR QUALITY)

SCOPING MEETING COMMENTS AND RESPONSES

The developers of East Altamont Energy Center have asked Western to interconnect the power plant with the agency's transmission system. Before Western can agree to the interconnection, it is bound by the National Environmental Policy Act (NEPA) to consider the project's environmental impacts. One of the first steps in the NEPA process is to ask the public to comment on the proposal, offer suggestions to improve the proposal, and even suggest alternative actions. The NEPA process of giving interested parties an opportunity to inform government agencies on environmental impacts is called "scoping."

An October, 2001 newsletter invited the public to a joint Energy Commission/Western scoping meeting in Livermore, California on November 14, 2001. The newsletter also served as Western's notification to prepare an environmental assessment (EA). A copy of the newsletter can be found at <http://www.wapa.gov/interconn/pdf/eastalt.pdf>. The newsletter provided a description of the overall NEPA process, the location of the meeting, and a form on the back to send in comments. Most of the comments originated in this public scoping meeting, but some were received later. On January 7, 2002 the public scoping public comment period closed for the proposed EAEC.

This section summarizes the questions and comments that Western received and describes how Western and the Energy Commission are addressing the issues raised.

Comment 1: *What are the public health impacts from the ammonia that is being used by EAEC and will there be odor down wind from the ammonia?*

Response: Approaches and procedures for handling ammonia are discussed in the Hazardous Materials section. Similar questions have been raised with Energy Commission staff. These comments and their responses can be found in the Response to Public and Agency Comments section at the following references: G&DK-1, G&DK-8, G&DK-17, G&MC-3, J&DH-1, and JHS-1. Responses can also be found in the Hazardous Materials section in the Response to Public and Agency Comments subsection.

Comment 2: *Three related comments include the following:*

> *Why has the applicant pursued easements on two different routes for the gas pipeline?*
>
> *Why have options been purchased to the south of the project site for the gas pipeline?*
>
> *Have easements been acquired for running a gas pipeline parallel to the canal and transmission lines?*

Response: A discussion of easements and routes for linear infrastructure, such as pipelines, can be found in the Biological Resources section in the Impacts from Linear Facilities subsection. Similar questions have been raised with Energy Commission staff. These comments and their responses can be found in the Response to Public and Agency Comments section at the following references: G&DK-6, and G&MG-3.

Comment 3: *In the photo provided by the applicant in the AFC, the stacks appear to be out of scale with the proposed landscape. A second comment asked the question, "Why did the applicant not provide more aerial photos showing the project site from other perspectives? The photos make the surrounding area look more rural that it truly is."*

Response: During the scoping meeting the project applicant indicated the stacks would be 175 feet tall as proposed. Additional information can be found in the Visual Resources Section.

Comment 4: *What kind of trees will be used in the landscaping around the power plant? How long will it take for the trees to mature to their maximum height? Will the trees cover the towers?*

Response: Similar questions have been raised with Energy Commission staff. These comments and their responses can be found in the Response to Public and Agency Comments section at the referenced comment, G&DK-19. Information about landscaping can be found in both the Visual Resources and the Biological Resources sections.

Comment 5: *How long will it take for the plant to be built?*

Response: The applicant plans to begin construction in 2003 and complete construction in 2005.

Comment 6: *Two comments related to distributed generation were raised. The first asked, why not size the plant to service the local community and avoid transmission line construction? The second asked, would not distributed generation serve a better purpose than the construction of a single large power plant?*

Response: Energy Commission and Western staff investigated distributed generation in the Alternatives Section, Alternatives Eliminated From This Analysis subsection. The Energy Commission concluded the following: "distributed energy is not a feasible alternative to the proposed project because of technical, institutional, and regulatory barriers." In this same section, Western has concluded that distributed energy generation is not consistent with Western's purpose and need to provide non-discriminatory open transmission line access.

Comment 7: *Is the plant a possible target for terrorist activity?*

Response: All private and public infrastructure is a possible target for terrorist activity. Potentially catastrophic accidents (which may be similar to terrorist events) are analyzed in the Hazardous Materials Management Section. In this section both the gas pipeline and ammonia tanks and procedures are evaluated. An emergency action plan and a fire prevention plan are required, as stated in the Worker Safety and Fire Protection Section.

Comment 8: *Is Western upgrading the power lines from west of Sacramento to Tracy? Is this upgrade related to the EAEC? Is the upgrade needed for he EAEC?*

Response: Western has proposed an upgrade of the existing transmission system. The proposed upgrades will be addressed in a separate environmental impact statement, currently scheduled for release in the fall of 2002. The need for the upgrade is independent and distinct from the proposed EAEC application for interconnection.

Comment 9: *Why does Western's cheap power go to preferred customers only?*

Response: Western's power allocations and rate setting procedures are established by Federal law and regulation.

Comment 10: *A member of the public voiced support for the proposed plant due to its proximity to support facilities and the state's need for power.*

Response: Comment noted.

Comment 11*: Could the power from the EAEC be sold out of state?*

Response: A similar question was raised with Energy Commission staff. This comment and the response can be found in the Response to Public and Agency Comments section at the referenced comment, G&DK-21.

Comment 12: *Will the Modesto Irrigation District's transmission line into the Tracy substation be upgraded? What is the final position of the transmission lines coming from the EAEC that tie into the existing transmission lines? Is the final location of the lines the same as has always been proposed?*

Response: The Tracy-Westley 230-kV transmission line would not be upgraded as part of the proposed EAEC project. The Tracy and Westley substations would be upgraded to accommodate the proposed interconnection. See the Transmission System Engineering Section for more information.

Comment 13: *Will the upgraded lines or the increased power from the EAEC increase electromagnetic fields? Could a house 400 feet away from the power lines have increased electromagnetic fields?*

Response: Electromagnetic fields are analyzed in the Transmission Line Safety and Nuisance Section.

Comment 14: *How much construction traffic will there be on the Mountain House and Kelso Road? What noise level will exist*?

Response: Traffic impacts are analyzed in the Traffic and Transportation Section. Noise impacts are assessed in the Noise and Vibration Section. Similar questions have been raised with Energy Commission staff. These comments and their responses can be found in the Response to Public and Agency Comments section at the following referenced comments, G&DK-3, G&DK-18.

Comment 15: *Can the EAEC be moved to the north on the existing* parcel?

Response: The project applicant responded that the plant couldn't be moved north because of restrictions limiting proximity to designated scenic routes. The Alternatives section includes an analysis of analyzed alternative sites for the proposed power plant.

AGENCIES AND PERSONS CONSULTED

AREA	ISSUE	CONTACT	ORGANIZAITON
Air Quality	Oversight of permit issuance, enforcement	Gerardo Rios	Chief, Permits Office USEPA Region IX
Air Quality	Regulatory oversight	Mike Tollstrup	Chief , Project Assessment Branch California Air Resources Board
Air Quality	Permit issuance, enforcement	William deBoisblanc	Director of Permit Services Bay Area Air Quality Management District
Biological & Water Resources	Potential impacts to endangered species in the Delta	Jeffrey Stuart	National Marine Fisheries Service
Biological Resources	Encroachment Permits	Bob Hendry	Contra Costa County Planning Dept.
Biological Resources	California threatened or endanger species	Janis Gann Dan Gifford	California Dept. of Fish and Game
Biological Resources	Encroachment Permits	Jeff Fischer	San Joaquin Planning Dept.
Biological Resources	Encroachment Permits	John Rogers	County of Alameda Public Works Agency
Biological Resources	Streambed Alteration Agreement	Joseph Powell	California Dept. of Fish and Game
Biological Resources	Waters of the U.S. and wetland impacts	Nancy Haley	U.S. Army Corps of Engineers
Biological Resources	Federal threatened or endangered species	Sheila Larsen Mike Nepstad	U.S. Fish & Wildlife Service
Biological Resources	Delta Fish	William E. Hearn	U.S. National Marine Fisheries Service
Cultural Resources	Federal agency NHPA Section 106 compliance	Daniel Abeyta Knox Mellon	California Office of Historic Preservation
Cultural Resources	Native American traditional cultural properties	Debbie Pilas-Treadway, NAHC	Associate Government Program Analysis
Cultural Resources	EAEC Cultural	Larry Myers	Native American Heritage Commission
Cultural Resources	EAEC Cultural	Lisa Asche	Alameda County Planning Dept.
Cultural Resources	EAEC Cultural	Robert O. Ueltzen	State Parks & Recreation
Fire Protection	Fire service coverage	James Ferdinand	Fire Marshal, Alameda County Fire Dept.
General	San Joaquin County's opposition to the EAEC	Lynn Bedford	Supervisor San Joaquin County Board of Supervisors
General	San Joaquin County's opposition to the EAEC	Phil Brown	San Joaquin County Board of Supervisors
Geologic Hazards and Resources	EAEC Geologic Hazards and Resources	Andy Cho	County Geologist, Alameda County
Geologic Hazards and Resources	EAEC Geologic Hazards and Resources	Jim Davis	State Geologist, California Division of Mines and Geology
Geologic Hazards and Resources	EAEC Geologic Hazards and Resources	Mark R. Bardley	Sr. Engineer Central Valley Regional Water Quality Control Board

AREA	ISSUE	CONTACT	ORGANIZAITON
Hazardous Materials	Fire Dept. Permits	Bob Bowman	Deputy Fire Marshal, Alameda County Fire Dept.
Hazardous Materials	Hazardous Materials Response	Jody Naff, Stan Silva or Vince Davis (depending on shift)	Battalion Chief, Alameda County Fire Dept., Haz Mat Support Unit
Hazardous Materials	Sensitive Receptors within a 3-mile Radius of the EAEC Site	Mountain House School District	3950 Mountain House Road
Hazardous Materials	Hazardous Materials Business Plan & Risk Management Plan	Rob Weston	Senior Hazardous Materials Specialist, Alameda County Environmental Health Dept.
Land Use Visual Resources		Adolph Martinelli	Agency Director, Alameda County Community Development Agency
Land Use	Contra Costa County Encroachment Permit	Bob Hendry	Public Works Permitting Engineer Contra Costa County, Permit Assistance Center
Land Use	Alameda County East County Area Plan (1994) "Measure D" Alameda County Zoning Ordinance (2000)	Bruce Jensen	Senior Planner Alameda County Community Development Agency, Planning Dept.
Land Use Traffic & Transp.		Bruce Jensen	Planner, Alameda County Community Development Agency
Land Use	Miscellaneous land use issues	Chandler Martin	San Joaquin County Planning Dept.
Land Use	Requirement to have a General Plan	Darren Ranelletti	Planner, Alameda County Community Development Agency
Land Use		James Sorensen	Planning Director, Alameda County Community Development Agency
Land Use	San Joaquin County General Plan (1992) San Joaquin County Zoning Ordinance (2000)	Jeff Fischer Michael Hitchcock	Planner San Joaquin County Planning Dept. Planner, Mountain House Project
Land Use	Delta Protection Commission	Jim Van Buren Roberta Goulard	Sr. Planner for Delta Protection Act guidance in General Plan Sr. Planner for Delta Protection Act guidance in General Plan
Land Use	Alameda County Encroachment Permit	John Rogers	Alameda County Public Works Agency, Development Services
Land Use	Contra Costa County General Plan (1996) Contra Costa County Zoning Ordinance (2000)	Patrick Roache	Senior Planner Contra Costa County Planning Dept.
Land Use	Miscellaneous land use issues	Paul Stenz	City of Livermore
Land Use	San Joaquin County Encroachment Permit	Reed Campbell	Public Works Permitting Engineer San Joaquin County, Public Works Dept.

AREA	ISSUE	CONTACT	ORGANIZAITON
Land Use	Miscellaneous land use issues	Vicki Lombardo	City of Tracy
Land Use & Soils	Prime farmland mapping	David Patch	Associate Environmental Planner, California Dept. of Conservation
Noise		Bob Hendry	Contra Costa County
Noise	EAEC Noise	Darin Ranalletti	Alameda County
Noise		Jeff Fischer	San Joaquin County
Public Health	Public exposure to acutely hazardous materials	Brian Bateman	Bay Area Air Quality Management District
Public Health	Public exposure to toxic air contaminants	Brian Bateman	Bay Area Air Quality Management District
Public Health	Public exposure to chemicals known to cause cancer of reproductive toxicity (Health & Safety Code 25249.5 et seq. (Safe Drinking Water & Toxic Enforcement Act of 186-Proposition 65)	Cynthia Oshita or Susan Long	Office of Environment Health & Hazard Assessment
Public Health	Public exposure to air pollutants (Clean Air Act)	David Howekamp	USEPA
Public Health	Public exposure to acutely hazardous materials (40 CFR Part 68 (Risk Management Plan)	David Howekamp Rob Weston	USEPA Region IX Alameda County Environmental Management
Public Health	Public exposure to toxic air contaminants	Ray Menebroker	California Air Resources Board
Public Health	Public exposure to acutely hazardous materials	Rob Weston	Alameda County Environmental Management
Public Health		Ronald Torres, R.E.H.S.	Supervising Environmental Health Specialist, Alameda County Health Agency
Socioeconomics	EAEC Socioeconomics	Allan Arjo	Director of Business Advisory Services Alameda County Office of Education
Socioeconomics	EAEC Socioeconomics	Barbara Claussen	Secretary to Principal West (Merril F.) High School
Socioeconomics	Labor Union Contacts	Barry Luboviski	Alameda Building Trades Council
Socioeconomics	EAEC Socioeconomics	Bryan Masterson	Alameda County Sheriff's Dept.
Socioeconomics	EAEC Socioeconomics	Chandler Martin	San Joaquin County Planning Dept.
Socioeconomics	EAEC Socioeconomics	Charles Farrugghia Bill Gaudinier	Administrative Lieutenant Acting Adm. Lieutenant Alameda County Sheriff's Office
Socioeconomics	EAEC Socioeconomics	Christine Fitzpatrick	Secretary to Director of Curriculum/Student Services Tracy Unified School District
Socioeconomics	EAEC Socioeconomics	Dolores Kuhn	Secretary, Mountain House Elementary School District
Socioeconomics	EAEC Socioeconomics	Dolores Ohm	Facilities Technician Tracy Unified School District

AREA	ISSUE	CONTACT	ORGANIZAITON
Socioeconomics	EAEC Socioeconomics	Elizabeth Evans	Chief of Appraisal Division Tax Manager Alameda County Office of the Assessor
Socioeconomics	EAEC Socioeconomics	Esther Lai Janet Allen Melanie Darling	California State Board of Equalization
Socioeconomics	Labor Union Contacts	Greg Feere	Contra Costa Building Trades Council
Socioeconomics	EAEC Socioeconomics	Jody Maas Bob Bowman Stanley Silva James Ferdinand	Battalion Chief Deputy Fire Marshall Battalion Chief, Battalion 2 Fire Marshall Alameda County Fire Dept.
Socioeconomics	EAEC Socioeconomics	Mike Lime	Assistant Manager, Emergency Room San Joaquin County Hospital
Socioeconomics	EAEC Socioeconomics	Ron Ray	Tracy Police Dept.
Socioeconomics	EAEC Socioeconomics	Sandra Hern	Office of Tax Manager, Alameda County
Socioeconomics	EAEC Socioeconomics	Tom Lum	Tax Manager, Alameda County Auditor Controller-Agency
Soils	Grading and trenching	Bob Hendry	Engineer, Contra Costa County Public Works
Soils	Grading and trenching	Gary Moore	Grading Supervisor, Alameda County Grading Dept.
Soils	Soil erosion	Leo Sarmiento	Water Quality Engineer, Regional Water Quality Control Board
Soils	Grading Permit	Rick Coates	Deputy Director, San Joaquin County Community Development
Traffic & Transportation	Transport oversized or excessive loads over State highways	Harold Burnett (Single Trip) Dee Garcia (Annual)	Caltrans
Traffic & Transportation		Karen Bormann	Alameda County Dept. of Public Works
Traffic & Transportation	Transport hazardous materials on Interstate highways Shipping of inhalation or explosive materials	Sgt. Deborah Pierce	California Highway Patrol
Transmission System Engineering		Gil Butler	Sacramento Municipal Utility District
Transmission System Engineering		Gregory Salyer	Modesto Irrigation District
Transmission System Engineering		Steven Ng	Pacific Gas & Electric
Tribal Contacts		Andrew Galvan	The Ohlone Indian Tribe Mission San Jose, CA
Tribal Contacts		Ann Marie Sayer	Indian Canyon Mutsun Band of Costanoan Hollister, CA
Tribal Contacts		Ella Rodriguez	
Tribal Contacts		Irene Zwierlein	Amah/Mutsun Tribal Band Woodside, CA
Tribal Contacts		Jakki Kehl	

AREA	ISSUE	CONTACT	ORGANIZAITON
Tribal Contacts		Katherine Erolinda Perez	
Tribal Contacts		Marjorie Ann Ried	
Tribal Contacts		Michelle Zimmer	Amah/Mutsun Tribal Band San Jose, CA
Tribal Contacts		Ramona Garibay	Trina Marine Ruano Family Fremont, CA
Tribal Contacts		Thomas Soto	
Visual Resources	Alameda County East County Area Plan Alameda County Scenic Route Element of the General Plan Alameda County Zoning Ordinance	Chris Bazar	Assistant Planning Director Alameda County Planning Dept.
Waste Management	Solid Waste	Karen Moroz	Senior Registered Environmental Health Specialist, Alameda County, Environmental Health Dept.
Waste Management	Nonhazardous Waste Solid Waste Planning, Source Reduction & Recycling	Lois Clarke	Program Manager, Alameda County Waste Management Authority
Waste Management	Hazardous Waste Hazardous	Rob Weston	Senior Hazardous Materials Specialist, Alameda County, Environmental Health Dept.
Water Resources	Water rights issues	Andrew Sawyer	Assistant Chief Counsel State Water Resources Control Board
Water Resources	Sewer / Storm Drainage and Flood Control	Bruce Jensen	Alameda County Senior Planner
Water Resources	Potential impacts of fresh water supply on the State Water Project and Delta	Dan Flory Nancy Quan Maureen Sergent	California Dept. of Water Resources
Water Resources	County Grading Permit	Gary Moore	Grading Supervisor, Alameda County Grading Dept.
Water Resources	Construction Activity NPDES Stormwater Permit	Leo Samiento	Central Valley Regional Water Quality Control Board
Water Resources	Wetlands Permit a404 (and Water Quality Certification, Section 401)	Nancy Haley	US Army Corps of Engineers
Water Resources	Industrial Wastewater Discharge Requirements (WDR) Title 27	Patricia Leary	Central Valley Regional Water Quality Control Board
Water Resources	Recycled water supply	Paul Sensibaugh	General Manager Mountain House Community Service District
Water Resources	Title 22 of the CAC (State) BBID Agreement to Serve	Rick Gilmore	General Manager Byron Bethany Irrigation District
Water Resources	County Stormwater Requirements	Robert Hale	Alameda County

AREA	ISSUE	CONTACT	ORGANIZAITON
Water Resources	Recycled water supply	Steven Bayley	Deputy Director City of Tracy Dept. of Public Works
Water Resources	General Industrial NPDES Stormwater Permit	Sue O'Connell	Central Valley Regional Water Quality Control Board
Water Resources	Title 27, Waste Discharge Requirements (State)	Victor Izzo	Senior Water Quality Engineer Central Valley Regional Water Quality Control Board
Water Resources	Recycled water supply	Virgle Koehne	General Manager Discovery Bay Community Services District
Water Resources	Streambed Alteration Agreement 1601	Warden Joe Powell	California Dept. of Fish and Game
Worker Health and Safety	EAEC Worker Health and Safety	Duty Officer	Duty Officer, Office of Emergency Services--Alameda County
Worker Health and Safety	EAEC Worker Health and Safety	Robert Weston or Ariu Levi	Hazardous Materials Specialist (notify in the event of a spill or hazardous materials release)

AIR QUALITY

Testimony of Tuan Ngo, P.E.

INTRODUCTION

In this analysis, staff 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, reported as NO_2), 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). Non-criteria air contaminants are addressed in the Public Health section of this document.

The 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 1744 (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, sections 1742.5 and 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, sections 1742.5 and 1742 (b).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

FEDERAL

The federal Clean Air Act requires the proponent of any new major stationary source of air pollution or any major modification to a major stationary source 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 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 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. Large sources are required to operate in compliance with the Title V requirements promulgated 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%O_2), and a SO_x emissions concentration of no more than 150 ppm@15%O_2.

STATE

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 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 prepared and presented to the Commission a Final Determination of Compliance (FDOC) on July 24, 2002. The FDOC evaluates whether and under what conditions the proposed project will comply with the District's applicable rules and regulations, as described below. Staff has incorporated the FDOC 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 SO_2 emissions 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 C.F.R. §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

SITE

The project site is located in the northeastern corner of Alameda County and, though physically in the San Joaquin Valley air shed, is subject to the rules of the Bay Area Air Quality Management District. The site is on the eastern slopes of the Diablo Range, one of several coastal mountain ranges bisecting the Bay Area from the northwest to the southeast. The range, from Mt. Diablo at 1312 meters (4305 feet) to the northwest and including Mt Hamilton at 1434 meters (4705 feet) to the southeast, bounds approximately 180 degrees to the southwest of the site. The open and flat San Joaquin Valley (less than 33 meters (100 feet) elevation) bounds the other 180 degrees to the northeast of the project site.

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 meters 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 Altamont 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 (11 to 33 mph), but may exceed 20 m/sec (45 mph).

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 (262 feet) in the morning to a high of 2,300 meters (7546 feet) in the afternoon. High mixing heights, normally associated with unstable conditions, can lead to greater dispersion of air contaminants (Smith et al. 1984). Low mixing height and calm wind, in addition to the terrain, can trap air contaminants 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 g/m^3).

AIR QUALITY Table 1
Ambient Air Quality Standards

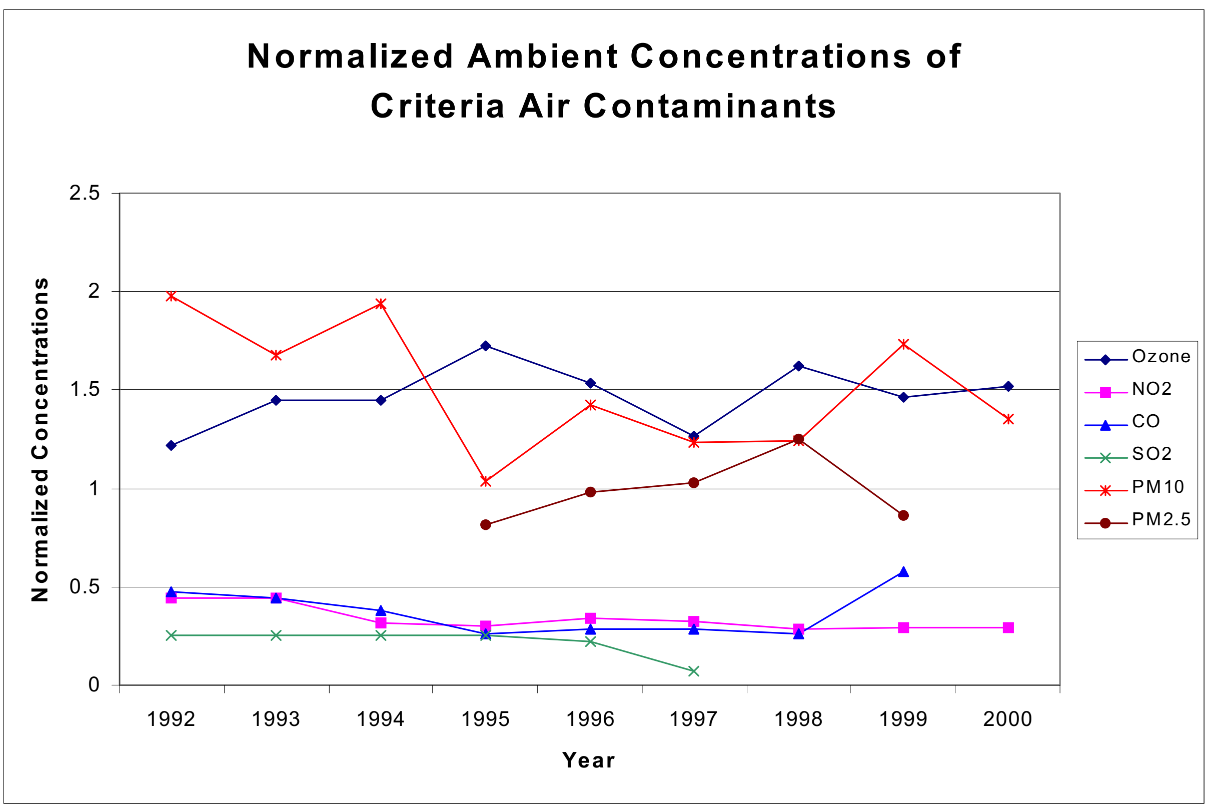
Pollutant	Averaging Time	California Standards	Federal Standards	
			Primary	**Secondary**
Ozone(O_3)	1-hour	0.09 ppm (180 g/m^3)	0.12 ppm (235 g/m^3)	Same as primary
	8-hour		0.08 ppm (157 g/m^3)	
Particulate Matter (PM_{10})	Annual Geometric Mean	30 g/m^3	---	Same as primary
	24-hour	50 g/m^3	150 g/m^3	
	Annual Arithmetic Mean	---	50 g/m^3	
Fine Particulate Matter ($PM_{2.5}$)	24-hour	No separate standard	65 g/m^3	Same as primary
	Annual Arithmetic Mean		15 g/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 g/m^3)	---	Same as primary
	Annual Arithmetic Mean	---	0.053 ppm (100 g/m^3)	
Lead(Pb)	30-day	1.5 g/m^3	---	Same as primary
	Cal. Quarter	---	1.5 g/m^3	
Sulfur Dioxide (SO_2)	Annual Arithmetic Mean	---	0.03 ppm (80 g/m^3)	---
	24-hour	0.04 ppm (105 g/m^3)	0.147 ppm (365 g/m^3)	---
	3-hour	---	---	0.5 ppm (1300 g/m^3)
	1-hour	0.25 ppm (655 g/m^3)	---	---
Sulfates	24-hour	25 g/m^3	No federal standard	
H_2S	1-hour	0.03 ppm (42 g/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 Bay Area 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. The air district to the east is the San Joaquin Valley APCD (SJVAPCD).

AIR QUALITY Figure 1 summarizes the historical air quality data near the project location for PM_{10}, CO, SO_2, O_3, and NO_2, measured either to the west in Livermore or the east in Stockton and Fresno (in the SJVAPCD). In **AIR QUALITY Figure 1**, the normalized concentrations represent the ratio of the highest measured concentrations in

AIR QUALITY Figure 1



Notes: CO, NO_2 and ozone data are from the Livermore monitoring station, $PM_{2.5}$ data are from Stockton, and SO_2 data are from the Fresno monitoring station.
Source: Air Resources Board.

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 nitrogen oxides and VOC in the presence of sunlight.

Ambient ozone concentrations recorded between 1992 and 2000 have ranged from 11 to 15 parts per hundred million (pphm). The area has experienced 5 to 22 days of violations of the state 1-hr ozone air quality standard every year since 1992. The available ambient ozone data show a slight increasing trend of ozone concentrations since 1992, so there is no clear indication that the ozone air quality is improving.

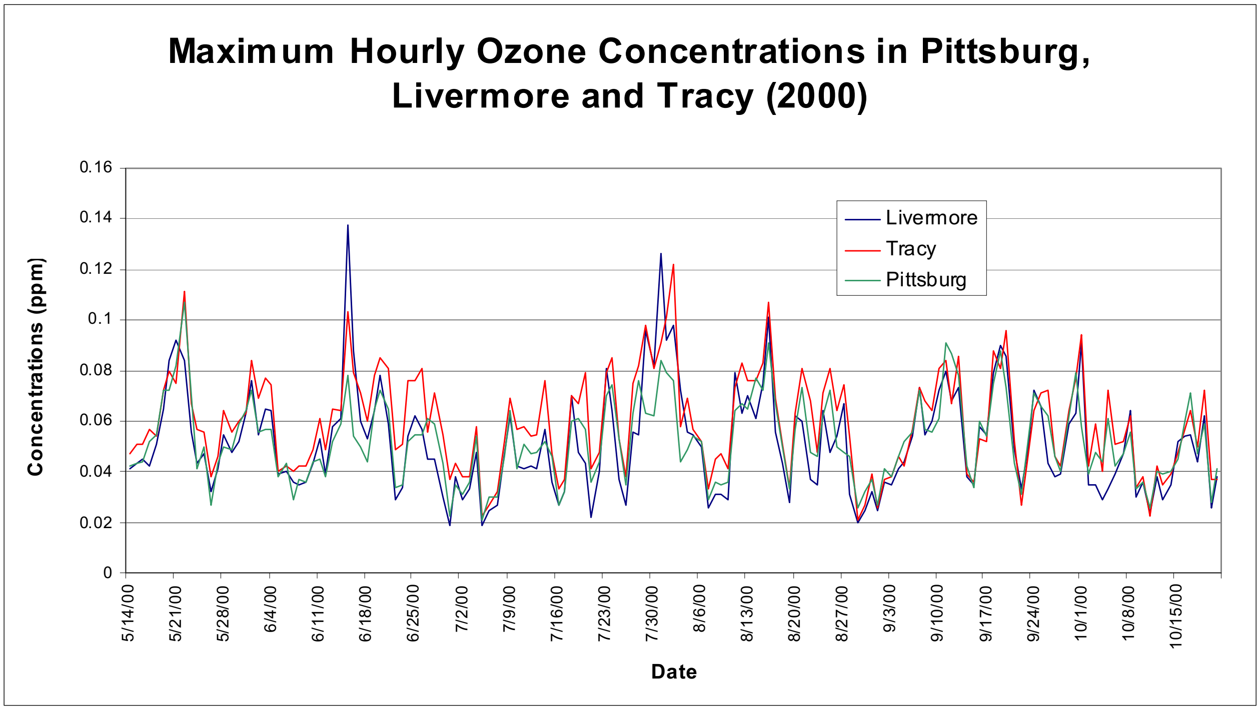
The 8-hour ambient ozone concentration recorded in the area was 9 pphm in 1992 and increased steadily to 11 pphm in 2000. These data indicate that the area would have exceeded the new federal 8-hour ozone standard (8 pphm) every year since 1992. The EPA has established the 8-hour ozone standard, but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

The project, by jurisdiction, is located in the BAAQMD , but is physically located in the San Joaquin Valley Air Pollution Control District (SJVAPCD) air shed. Energy Commission and SJVAPCD staffs believe that the project emissions will significantly affect the San Joaquin Valley air quality. The SJVAPCD has signed Air Quality Mitigation Settlement Agreements with both the EAEC and Tesla[1] project owners stipulating to “the migration of air pollutants” into the San Joaquin air basin “without the corresponding benefits from offsets provided in BAAQMD”. As such, mitigation measures such as emission reduction credits that originate from Antioch, Oakland, San Leandro, Redwood City, and San Jose may not be as effective in reducing the project impacts on ambient air quality as credits located in the San Joaquin Valley.

Because Energy Commission staff believes that the applicant’s proposed Antioch/Pittsburg emission reductions cannot fully mitigate the project’s emission impacts in the local area, staff needs to determine how much more local emission reductions must be provided to reduce the project’s emission impacts to a level of less than significant. Staff reviewed ambient air quality concentrations in the areas of Pittsburg, Livermore, and Tracy to attempt to establish a nexus of transport of air pollution in these three areas.

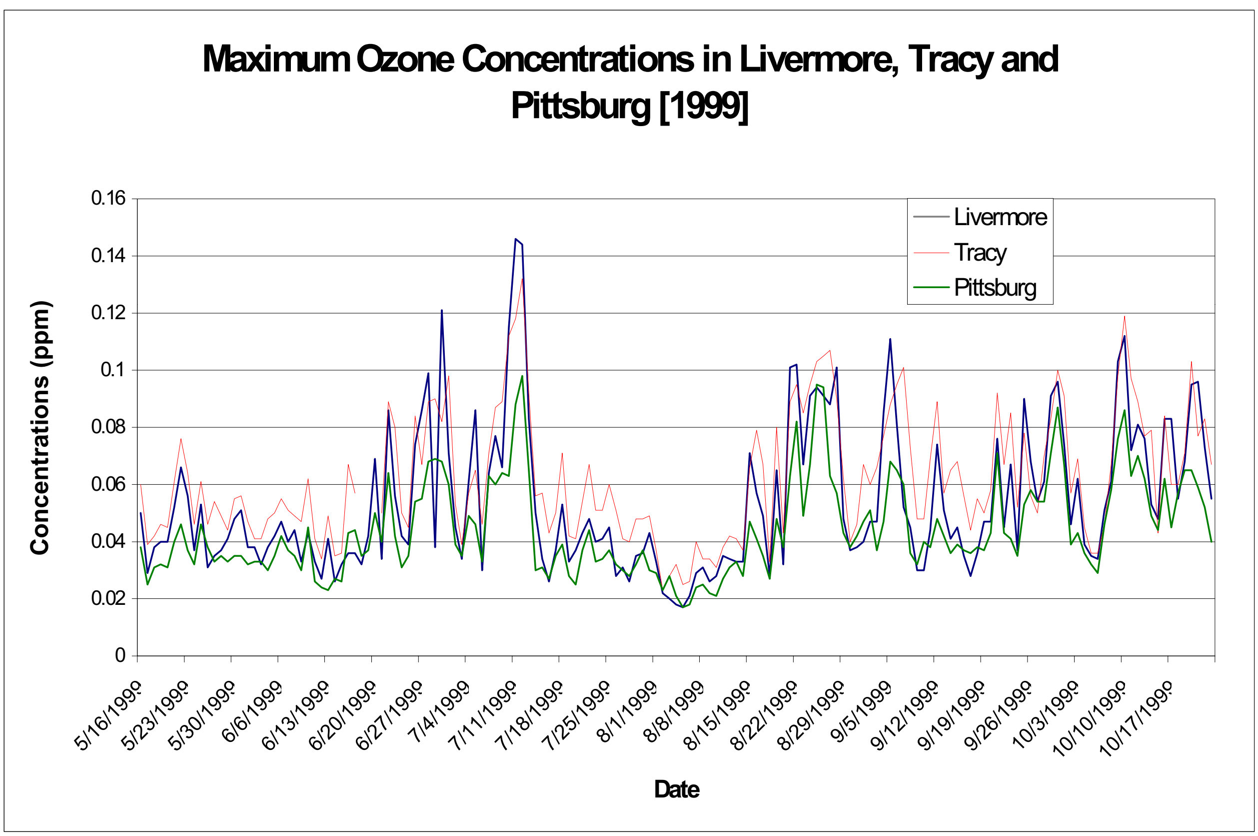
[1] The Tesla Power Project is also located east of Altamont Pass in Alameda County near the San Joaquin county line.

AIR QUALITY Figure 2



Source: Air Resources Board.

AIR QUALITY Figure 3



Source: Air Resources Board.

Staff plotted the ozone concentration data in graphical form in **AIR QUALITY Figures 2 and 3** for the most recent (1999-2000) ozone ambient concentrations for the two consecutive ozone seasons (May-October) for Pittsburg, Livermore, and Tracy. Staff observes that the recorded ozone concentrations in Pittsburg, Livermore, and Tracy behave as if they are all located in the same air basin, i.e., the ozone concentrations peaked and ebbed in a highly correlated relationship almost 95% of the time during the ozone season. Staff also observed that the average ozone concentration in Tracy is 15 percent higher than that in Livermore, and is 30 percent higher than that in Pittsburg. Staff concludes that the air mass experiences a net increase in emissions as it moves from Pittsburg to Tracy. In other words, the emissions generated between Pittsburg and Tracy contribute approximately 30 percent to the area's ozone levels, and the emissions from the Pittsburg/Antioch area contribute approximately 70 percent of the area's ozone levels. Therefore, staff considers that emission reduction credits generated in the Pittsburg/Antioch area would be 70 percent effective in mitigating impacts in the San Joaquin Valley. The remaining 30 percent of the emission reduction credits would offer no appreciate value in mitigating the project's ozone impacts in the San Joaquin Valley.

Staff then analyzed the proposed emission reduction credits located in the Oakland, Redwood City, San Leandro, and San Jose areas. An ARB staff report had studied and performed modeling exercises to establish the impacts of pollutants that are transported from the Bay Area and Sacramento Valley to the San Joaquin Valley on the valley's ozone concentrations (ARB, 1994). The ARB modeling exercises showed that the Bay Area emissions contributed approximately 27 percent to the peak ozone levels in the Valley. Relying on this analysis, staff concludes that 27 percent of the ozone precursor emissions reduction credits proposed by the applicant from the Oakland area mitigate project local, or Northern San Joaquin, impacts during the ozone season (between June to September). SJVAPCD, in the Tesla Power Project Air Quality Mitigation Agreement between the Tesla project owner and the SJVAPCD, also estimates the benefit of BAAQMD ERCs west of Altamont Pass on San Joaquin Valley to be 27 percent. The remaining 73 percent of the BAAQMD emission reduction credits offer no appreciable value as a mitigation measure for the proposed project's ozone impacts in the San Joaquin Valley.

Nitrogen Dioxide

Ambient NO_2 levels measured between 1992 and 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.

Carbon Monoxide (CO)

The highest CO concentration levels measured between 1992 and 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 (PM_{10})

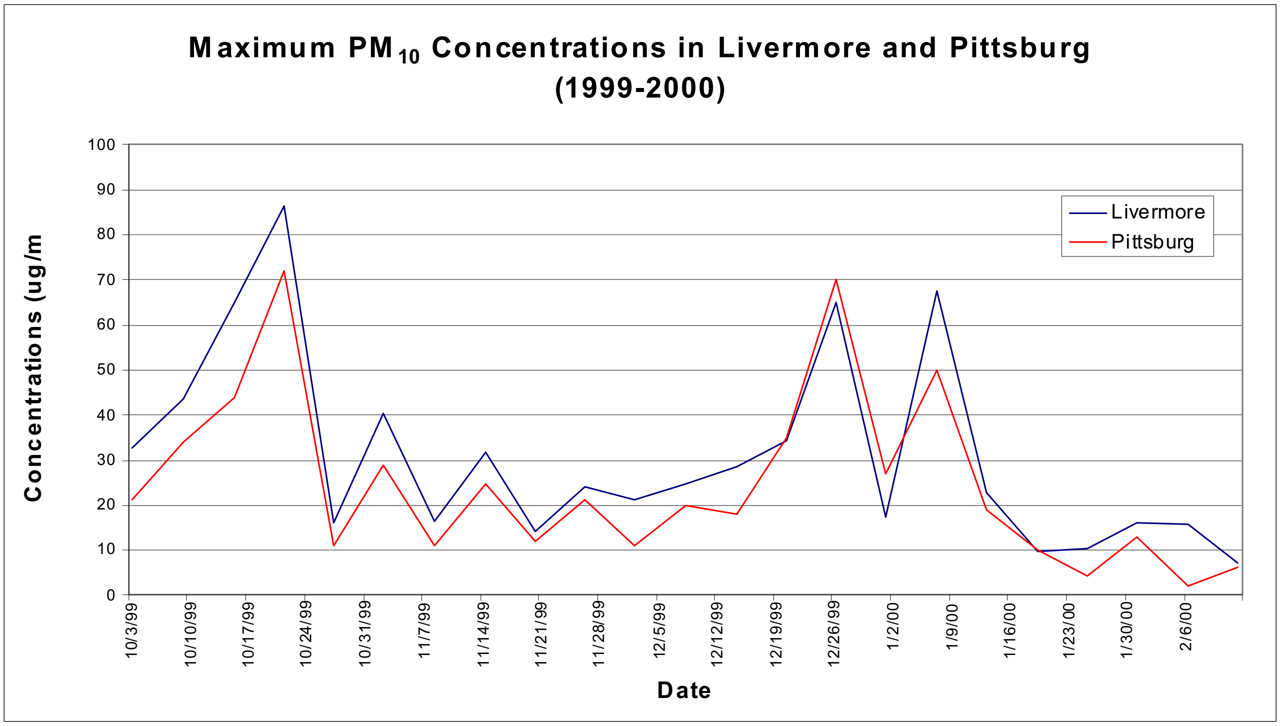
As shown normalized in **AIR QUALITY Figure 1**, PM_{10} concentrations measured near the project site show that the area has experienced violations of the state 24-hour PM_{10} standard every year between 1992 and 2000. During this period, the area experienced between 6 and 30 calculated violation days a year 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 contributions of PM_{10} are from wood smoke, combustion of fossil fuels, and entrained dust particles (BAAQMD 2000).

Similar to the reasons discussed in the ozone air quality setting, staff does not believe that the applicant's proposed PM_{10} emission reduction credits fully mitigate the project PM_{10} impact to the local area. To investigate the effectiveness of the proposed PM_{10} mitigation, staff analyzed the PM_{10} ambient air quality between Pittsburg and Tracy. Unfortunately, ambient PM_{10} concentration data for Tracy is not available, so staff used the PM_{10} data for Pittsburg and Livermore, and the previously discussed ozone concentration data to assess the local PM_{10} contribution. **AIR QUALITY Figures 4 and 5** represent the maximum 24-hour PM_{10} concentrations recorded in Pittsburg and Livermore for the two PM_{10} seasons in 1999 and 2000. Staff estimates that the emissions generated in the area between Pittsburg and Livermore contribute approximately 18.4 percent of the PM10 problem.

Due to the lack of PM_{10} concentration data in Tracy, cannot assess the percentage contribution of PM_{10} emissions in the area between Livermore and Tracy. Because of the similarity between the recorded PM_{10} concentration data and the ozone concentration data, staff assumed that the PM_{10} emissions generated in the area between Livermore and Tracy would contribute the same percentage as does the ozone contribution. Using this assumption, staff concludes that the emissions reduction credits from the Pittsburg/Antioch area would be 70 percent effective in mitigating the PM_{10} problem downwind. The remaining 30 percent of the emission reduction credits offer no appreciate value in mitigating the project's contribution to the area PM_{10} problem.

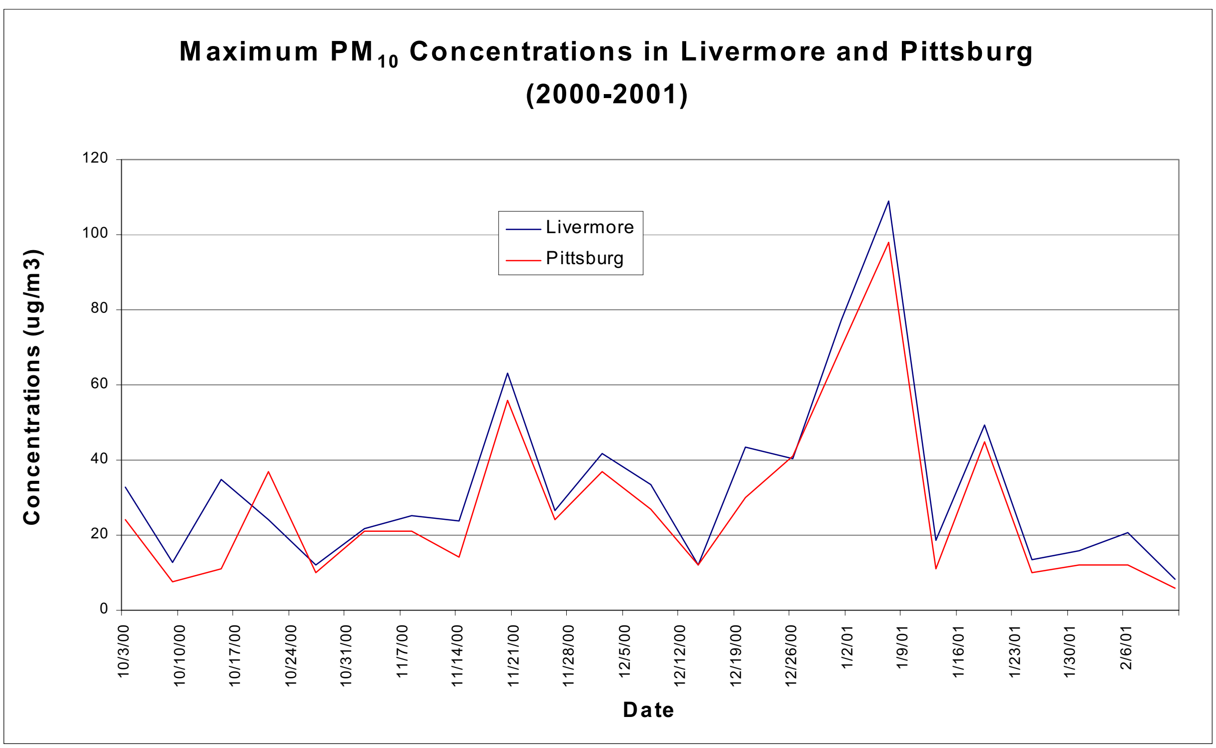
For similar reasons described in the ozone air quality setting, staff believes that 27 percent of the PM_{10} emissions reduction credits from the Oakland, San Leandro, San Jose, and Redwood City areas would mitigate project PM_{10} emission impacts to the local area and the San Joaquin Valley. The remaining 73 percent of the emission reduction credits offer no appreciable value as a mitigation measure for the proposed project's PM_{10} impacts in the San Joaquin Valley.

AIR QUALITY Figure 4



Source: Air Resources Board.

AIR QUALITY Figure 5



Source: Air Resources Board.

Fine Particulate Matter ($PM_{2.5}$) **Air Quality Figure 6** shows the available $PM_{2.5}$ concentrations measured at various air quality monitoring stations in the Bay area during the period from 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. [$PM_{2.5}$ ambient concentrations data are not available in the Tracy area, thus the applicant has provided an analysis and used ambient air quality data recorded in the Livermore area as representative of the local area (EAEC, 2001a)].

In a study by the Desert Research Institute (DRI, 1998) for the California Regional PM_{10}/$PM_{2.5}$ Air Quality Study Technical Committee, the following observations can be drawn from ambient concentration data between 1999 and 2001:

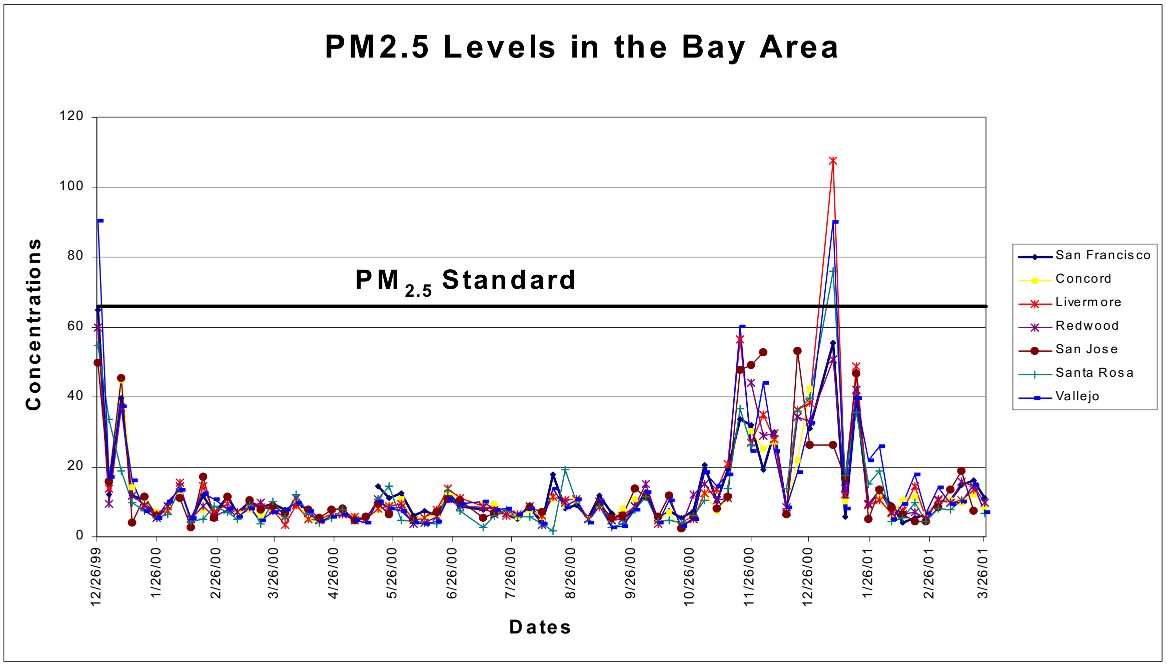
The highest PM_{10} and $PM_{2.5}$ concentrations occur in wintertime (between mid-November to mid-February).

Secondary $PM_{2.5}$ derived from NO_x (ammonium nitrate) is the largest component, often constituting more than 50 percent of $PM_{2.5}$ in urban areas, and higher in non-urban areas.

Organic and elemental carbons are the next largest component, constituting between 25 to 50 percent of $PM_{2.5}$.

Secondary $PM_{2.5}$ derived from SO_x (ammonium sulfate) and fugitive dust constitute the rest of the $PM_{2.5}$.

AIR QUALITY Figure 6



Source: Air Resources Board.

PROJECT EMISSIONS

CONSTRUCTION ACTIVITIES

Construction of the proposed project is expected to 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.

In addition to emissions from construction equipment exhaust, such as vehicles and internal combustion engines, 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

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

PROJECT OPERATION

The project would 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.

Once built, the turbines would be operating in combined cycle mode to produce approximately 1,100 MW of electricity. The applicant proposes to equip each combustion turbine with 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 8 hours a day without the operation of the duct burner, then

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 emergency generator and the diesel fire pump are expected to operate 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 on any one day for a period no longer than 1 hour (EAEC, 2001a). Therefore, the emissions from testing of these two pieces of equipment will be included in the facility's total emissions.

The applicant provided staff with 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 eventually provided some preliminary emissions data for the turbines, and the SCR system emissions guarantee for the turbine/HRSG power train (EAEC, 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. In response to a staff data request, the applicant 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 (EAEC, 2001c). A turbine's start-up emissions are generally higher than the uncontrolled, steady state operation emissions. Therefore, staff had 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 would last 3 hours, and each hot start would last one hour.

The East Altamont facility would employ three-GE frame 7FB turbines. Because the start-up emissions data 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 similar facility uses three GE frame 7FA turbines and has guaranteed NO_x emissions of 9 ppm without the use of SCR (Appendix A). Because the EAEC proposed turbines (7FB model) are larger, staff has linearly adjusted the 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 9 ppm) are 80 lbs and 67 lbs per hour, per turbine, respectively. Because the proposed FB model gas turbines have higher NO_x 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's 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.

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 starts, 5,100 hours steady state operation with duct burners, and the rest (3,085 hours) steady state operation without the use of duct burners.

The applicant has requested and agreed to conditions that would restrict the facility's annual emissions to the levels presented in the last row of **AIR QUALITY Table 4**.

AIR QUALITY Table 3
Power Train Emissions Estimates

Start-up emissions (Staff estimates)	**NO_x**	**SO_2**	**PM_{10}**	**VOC**	**CO**
Cold (total emissions for 4 hours, lbs)	2,640	N/A	N/A	2,160	3,350
Hot (total emissions for 90 minutes, lbs)	900	N/A	N/A	810	1,350
Start-up emissions (Applicant estimates)					
Cold (total emissions for 3 hours, lbs)	720	N/A	N/A	48	2,514
Hot (total emissions for one hour, lbs)	240	N/A	N/A	16	902
Steady state @ 100% load (Applicant estimates) (lbs/hr)	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[1,3] (tons/year)	443	86	216	219	1,150
Maximum permitted annual emissions including start ups and shutdown[4] (tons/year)	263	24	148	74	794

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.
4 These are the permitted annual emissions limits, including all start up and shut down events, that the facility shall not exceed.

INITIAL COMMISSIONING

Initial commissioning refers to a period of approximately 60 days prior to beginning commercial operation when the combustion turbines undergo initial test firing. During this commissioning phase, the project may operate at a low-load for a 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 minimized to lessen the impacts 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 or operation of the facility; therefore, staff expects no new impacts from the NOx and CO 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 would cease to operate and thus all impacts associated with those emissions will no longer occur. The only other expected emissions would 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. Dismantling activities, although short term, could be similar to those of construction because of demolition, equipment tailpipe emissions, and fugitive dust from re-grading. 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 (EAEC, 2001a). On a daily basis, a 10 ppm slip is equivalent to approximately 2,500 pounds per day 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 (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 (EAEC, 2001a). The applicant's modeled impacts were added to the available highest ambient background concentrations measured from 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.

AIR QUALITY Table 5
Facility Maximum Construction Impacts

Pollutant	Avg. Period	Project Impact (g/m^3)	Background (g/m^3)	Total Impact (g/m^3)	State Standard (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.	30[1]	87	117	50	230

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

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.

Construction of the facility would result in unavoidable short-term PM_{10} impacts. Because the area is non-attainment for PM_{10}, additional impacts during construction of the project can be viewed as significant. However, it is doubtful that the general public would be exposed to the construction impacts associated with the project. Staff reviewed the modeling files and believes that the likely PM_{10} construction impacts during the day would be in the range of 20 to 30 g/m^3. Nevertheless, because the area PM_{10} standard is already violated, the construction of the project would exacerbate the existing violation. Therefore, the project's construction PM_{10} emission impact is significant.

Staff believes that the PM_{10} impacts from the construction of the project can be mitigated with the implementation of the staff recommended construction mitigation measures, as discussed in the **Mitigation** section.

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 listed in the table, 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. That standard is based on the protection of public health and includes a margin of safety to protect sensitive members of the population. Thus, project emissions that contribute to existing violations of that standard have the potential to exacerbate public health problems associated with existing ambient PM concentrations (please see Attachment A to staff's **Public Health** analysis). Staff therefore views the project's PM_{10} emissions and associated impacts as significant.

AIR QUALITY Table 6
Facility Operation Emission Impacts on Ambient Air Quality

Pollutant	Avg. Period	Project Impact (g/m^3)	Background (g/m^3)	Total Impact (g/m^3)	Most Restrictive Standard (g/m^3)	Percent of Standard
NO_2	1-hour (start up)	236	149	385	470[1]	80
	1-hour (steady-state)	20	149	169	470[1]	36
	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 standard [2] Federal standard Source: EAEC, 2001a. Table 8.1-29.

CUMULATIVE 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 a permit application with the District. Projects located up to six miles from the proposed facility usually need to be included in the analysis. Staff believes that the direct emissions from any project located beyond six miles of EAEC would not affect the cumulative modeling analysis. The District indicated that there is no source that 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 (Mountain House) of approximately 10,000 acres will be built adjacent to the proposed facility.

The Mountain House Environmental Impact Report (EIR) concludes that, among other impacts, the development of the new town would increase emissions of NO_x, VOC, SO_x and PM_{10}. All of these would contribute to the existing violations of ozone and PM_{10} standards in the San Joaquin Valley and the San Francisco air basins, and thus will interfere with the progress toward attainment of the above air quality standards. The San Joaquin County Board has approved the development of the new town with overriding considerations of unmitigated significant impacts to air quality.

Because the development of the new Mountain House community would result in a significant impact to air quality, the addition of new emission sources would further worsen that impact. Staff believes that under certain meteorological conditions, such as when the wind is calm and the weather is hot, the emissions from all three proposed power plants combined with the emissions from the development of the Mountain House community could cause a significant cumulative air quality impact.

SECONDARY POLLUTANT IMPACTS

Secondary air contaminants are those that are not directly formed in, or emitted from, the stacks of the equipment such as the project's turbines, boiler or emergency engine. These air contaminants are formed outside of the stacks as a result of chemical reactions involving the directly emitted pollutants. For example, ozone can be formed by photochemical reactions between NO_x and VOCs in the presence of sunlight in the atmosphere.

Ozone impacts

The proposed project's NO_x and VOC emissions can contribute to the formation of ozone. There are air 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.

Secondary PM_{10} impacts

The project's NO_x, VOC, NH_3 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}.

Staff believes that the project's ammonia emissions could contribute to the formation of ammonium nitrate in the area, potentially worsening 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 and 30 percent per hour in a polluted urban area where ozone and ammonia are present in sufficient amounts to participate in the reaction. Staff assumed a 30 percent NO_x to nitrate conversion rate (the upper end of the conversion rate based on the area's continuing ozone violations and worsening trend) as well as a linear extrapolation of the project's PM_{10} modeling results. Staff estimates the maximum NO_x to nitrate impact from the project to be 4 g/m^3. Because the area is non-attainment for the state 24-hr PM_{10} and possibly the federal 24-hour $PM_{2.5}$ standards, the ammonium nitrate contribution, although small, would be significant. 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 nitrate to the local area.

Concerning sulfates as PM_{10}, staff believes that the project's SO_2 emissions will contribute to sulfate levels in the area, although in a very small amount. Currently, there are 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 Energy Centers) indicating that the potential conversion of SO_2 to particulate matter could be as high as 35 percent.

Using a conservative 35 percent conversion of SO_2 to particulate matter, the project's SO_2 emissions are expected to add an impact equivalent to 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 PSD Class I areas (EAEC, 2001a). Class I areas are areas of special national or regional value from a natural, scenic, recreational, or historic perspective. The District's issuance of the FDOC indicates that the visibility impact analysis is adequate.

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 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 its 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. Staff will include requirements in the conditions that these control measures also apply to the construction of the linear facilities.

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). Control devices include dry low-NO_x combustion design, SCR and oxidation catalyst technology for each of the combined cycle turbine trains to minimize their 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, over a 1-hour period (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^{o}F.

Catalysts generally operate between 600 to 750^{o}F (ARB 1992), and are normally placed inside the HRSG where the flue gas temperature has cooled. At temperatures lower than 600^{o}F, the ammonia reaction rate may start to decline, resulting in increasing ammonia emissions, called ammonia slip. At temperatures above about 800^{o}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^{o}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 technology 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. The District, in its FDOC, has required that the maximum NO_x concentration is to be maintained at 2.0 ppm (BAAQMD, 2002c).

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 (CO_2). The CO catalyst is proposed to limit the CO concentrations to 6 ppm at 15 percent O_2. The District, in its FDOC, has required that the maximum CO concentration is to be maintained at 4.0 ppm (BAAQMD, 2002c).

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 7**. The applicant has provided some emission reduction credits, in the form of District issued banking certificates, for 305 tpy of NO_x, 87.5 tpy of VOC, and 2.2 tpy of PM_{10}. In addition, the applicant will provide 444 tons of SO_2 emission reduction credits to mitigate the project's 148 tons per year of PM_{10} emissions.

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 it to do so.

ADEQUACY OF PROPOSED MITIGATION MEASURES

CONSTRUCTION PHASE MITIGATION

As mentioned earlier in the impact section, construction of the project would cause PM_{10} emissions that would add to the existing violations of the ambient PM_{10} air quality standard. Therefore, staff concludes that the project PM_{10} emission impacts due to construction of the project are significant. As a result, staff is proposing Conditions of Certification **AQ-SC1** through **AQ-SC4** that would require the project applicant employ measures designed to further control project and linear construction-related emissions. Staff believes that the implementation of these mitigation measures would reduce project and linear construction-related impacts to a level less than significant.

AIR QUALITY Table 7
Maximum Annual NO_2, VOC, and PM_{10} Emissions and District Offset requirements

Pollutant	New Emissions from EAEC (tpy)	Offset Ratio for BAAQMD[1]	Offsets Required by BAAQMD[1] (tpy)	Offsets proposed by Calpine (tpy)
NO_2	263	1.15:1	302	***305*** (Calpine)
VOC	74	1.15:1	85	***87.5*** (Calpine)
PM_{10}	148	3:1 SO_2:PM_{10}	444	***444*** (Calpine)
SO_2	24[2]	N/A	0	***0***

Notes: 1 Offset ratio as required by the BAAQMD.
2 Staff estimates project's SO_2 emissions using an annual average of 0.28 gr. of sulfur/100 scf natural gas.

OPERATIONAL PHASE MITIGATION

The project will be built using BACT (clean burning using natural gas, SCR and CO oxidation catalyst systems) in accordance with the District NSR.

The proposed project would add 263 tpy of NO_x, 74 tpy of VOC, 148 tpy of PM_{10}, and 24 tpy of SO_2 to the San Joaquin Valley air shed. The applicant has proposed to provide 305 tpy of NO_x, 87.4 tpy of VOC, and 444 tpy of SO_2 emission reduction credits, in the form of the Bay Area District issued banking certificates, as offsets. These banking certificates were issued for emission reductions in San Leandro (certificates #645, 687), Redwood City (#716), Oakland (#602, 662), San Jose (#661), and Antioch (#741, 749). These proposed emission offsets are consistent with the Bay Area District NSR rule, but because of the distance between the source of offsets and the proposed facility, the proposed offsets may not fully mitigate the project impacts on the local ambient ozone and PM_{10} air quality. As staff has discussed in the **SETTING** section, additional local ozone precursors (NO_x and VOC) and PM_{10} emission reduction credits need to be provided to lessen the facility local impact to a level of less than significant. **AIR QUALITY Table 8** represents staff's estimate of the equivalent effectiveness of the applicant's proposed emission reduction credits in reducing the project impacts to the local area and the valley. In the same table, staff also presents the amount of emissions reduction credits to be secured in the area to mitigate the project to a level of less than significant. According to staff estimates, the applicant would need to secure 133 tpy of NO_x, 42 tpy of VOC, and 50 tpy of PM_{10} local emission reduction credits.

To arrive at the equivalent effectiveness values of the applicant's proposed emission reduction credits, staff referred to several studies: the ARB staff's study of the potential effect of pollutants from the Bay Area on the San Joaquin Valley, the staff analysis of the ambient air quality recorded in Pittsburg/Livermore/Tracy areas; and the San Joaquin District Air Quality Mitigation Agreement with Florida Power and Light for the Tesla project. In that agreement, the SJVAPCD staff used an average effectiveness for the Bay Area's emission reduction credits west of Altamont Pass of 27 percent.

As mentioned in the **SETTING** Section, the ARB has concluded that Bay Area air contaminants contribute approximately 27 percent to the San Joaquin Valley's peak ozone level. Thus, emission reduction credits from the general Bay Area can be said to be 27 percent effective in mitigating the project impacts. The remaining balance of 73 percent has to come from the local area.

AIR QUALITY Table 8
Staff Estimated Additional Local Emission Reductions

	Face Values of Credits from the Bay Area (tpy)				Equivalent Effectiveness[1] (tpy)			
Certificate Number, Location	NO_2	VOC	PM_{10}	SO_2	NO_2	VOC	PM_{10}	SO_2
645, 687 San Leandro	108	44	0	0	29	12	0	0
716 Redwood City	12	0	1	0	3	0	0	0
602, 662 Oakland	76	41	0	46	21	11	0	12
741, 749 Antioch	110	0	0	437	77	0	0	306
661 San Jose	0	32	0	0	0	9	0	0
Total	305	117	1	483	130	32	0	318
Project Emissions					263	74	148	24
Excess or <Shortfall>					<133>	<42>	<148>	294[2]
Additional emission reductions needed (tons)					**133**	**42**	**50**[3]	**0**

Notes:
1 The equivalent effectiveness means the emission reduction credits that can effectively mitigate the project's impacts. For the credits in Antioch, staff has assigned 70% effectiveness, while those credits in Oakland, San Leandro, Redwood City and San Jose were assigned a 27% effectiveness (see SETTING Section).
2 There are 294 tons per year of excess SO_2 that can be used for inter-pollutant trading for PM_{10} at a ratio of 3 to 1.
3 There are 50 tons per year of PM_{10} that need to be secured after the use of excess SO_2 as inter-pollutant trading for PM_{10} , i.e., using an inter-pollutant trading ratio of 3:1, 294 tpy of SO_2 is equivalent to 98 tpy of PM_{10}.

As mentioned in the **SETTING** Section, staff evaluated the recorded ambient concentrations of ozone and PM_{10} in the Pittsburg/Livermore/Tracy areas, and concluded that 70 percent of the ozone and PM_{10} emissions generated in the Pittsburg/Antioch area contribute to ambient ozone and PM_{10} levels in the Livermore/Tracy area. Thus, the emission reduction credits from the Pittsburg/Antioch area can be said to be 70 percent effective in mitigating the project impacts. Again, the remaining balance of 30 percent should come from the local area.

After applying each of the appropriate effectiveness ratios mentioned above, the equivalent effectiveness emissions reductions were adjusted and entered in **AIR QUALITY Table 8**.

The difference between the project emissions and the equivalent emission reduction credits shows either a mitigation shortfall, or excess. These values are presented in the next to last row of **AIR QUALITY Table 8**. This row shows that the project would experience a shortfall of 133 tpy of NO_2, 42 tpy of VOC, and 148 tpy of PM_{10}. This row also shows that the project would experience an excess of 294 equivalent tpy of SO_2 emission reduction credits.

The applicant proposes to use the excess SO_2 emission reduction credits to inter-pollutant trade for PM_{10}, at a ratio of 3 pounds of SO_2 for every pound of new PM_{10} emission. The applicant has provided 294 tpy of SO_2 emission reduction credits, which, using the above ratio, is equivalent to 98 tpy of PM_{10}. The project PM_{10} emissions would be 148 tpy, thus the project would still experience a shortfall of 50 tpy of PM_{10} as indicated in the last row of **AIR QUALITY Table 8**.

The applicant and the SJVAPCD have jointly reached in concept to an "Air Quality Mitigation Agreement," patterned after a similar agreement for the Tesla Power Project, to address the potential transport of project emissions to the San Joaquin Valley. This agreement is in a conceptual stage, and will need approval by the San Joaquin Valley Air Pollution Control Board to be in effect.

According to the SJVAPCD staff, the Tesla "Air Quality Mitigation Agreement" would require the applicant to pay a "Mitigation Fee" that the SJVAPCD would use to create air quality benefits in the valley. Although the agreement's stated preference is that the program would generate benefits within the Northern Region of the AQMD, particularly within or near the City of Tracy, there is no guarantee that the emission reductions would be generated in the local area. The fee could be used for bus retrofitting/replacement, lawnmower replacement, or retrofit/replacement of heavy-duty internal combustion engines. The quantity, schedule, and permanence of emission reductions that could occur via such an agreement are not specified.

Staff has serious concerns about the vagueness of the above agreement, especially about the locations and the amount of actual emission reductions that would be generated using the settlement funds. The agreement mentions that funding would be used to generate reductions from retrofitting or replacing buses, replacing lawnmowers, and/or replacing or retrofitting internal combustion engines. However, the proposal does not identify specific vehicle fleets, engines, or locations of specific controls that would be implemented, or the quantities of emission reductions that would occur. Staff needs to identify specific mitigation measures so that we can determine whether those mitigation measures actually would lessen or eliminate the proposed project's impacts.

Mitigation measures (such as providing fees for unspecified air quality mitigation purposes) that are not tied to specific action plans may not be adequate or effective in reducing project related impacts. In general, an agency cannot rely on a mitigation measure of unknown efficacy in concluding that a significant impact will be mitigated to a less than significant level. In order for staff to reasonably conclude that impacts will be mitigated to less than significant, any mitigation measure must include realistic performance standards or criteria that will ensure the mitigation of the significant effects. In order to rely on a mitigation plan, staff needs to possess meaningful information reasonably justifying an expectation of compliance. Staff regards meaningful information to include:

a clear explanation of the measure’s objectives (an accounting of the emissions reductions to be provided by the implementation),

a description of specific measures designed to provide the necessary reductions, how the implementation will occur, who is responsible for the implementation, where the implementation will occur, the timetable for implementation, and measures to verify performance.

In the absence of such information, staff cannot reasonably be assured that the SJVAPCD and applicant agreement has a high likelihood of mitigating the project impacts.

Notwithstanding the above mitigation agreement, the applicant has submitted a list of “consensus” mitigation measures, which combines measures suggested by the Commission staff, the applicant and the SJVAPCD (EAEC, 2002sss). The measures consist of:

1. Providing natural gas transit buses, and a natural gas refueling station to the Tracy Regional Transit. These buses will be used to transport the passengers from the Tracy, Mountain House, and Livermore areas to the BART station in Livermore. The purpose of this measure is to reduce the number of single drivers and their vehicles commuting to San Francisco.
2. Replacing the diesel school buses with newer, natural gas school buses to reduce the students' exposure to diesel exhaust.
3. Installing solar panels at the Mountain House School to provide active demonstration of local generation and load reduction.
4. Renovation of the Mountain House School parking lot to reduce fugitive dust and relieve traffic congestion at the school.
5. Providing an ultra-low sulfur diesel refueling station for construction equipment at the new Mountain House community to reduce the equipment's SO_2, PM_{10} and VOC emissions.
6. Providing funding to subsidize the cost of replacing of old wood stoves with newer, EPA certified units to reduce PM_{10} and VOC emissions
7. Providing funding to subsidize the cost of retrofitting fireplaces with natural gas to reduce PM_{10} and VOC emissions.
8. Providing funding to retrofit or replace heavy-duty on-road, or agriculture engines to reduce NO_x and PM_{10} emissions.

The applicant has offered an analysis of the potential emission reductions and the cost-effectiveness of each of the above individual mitigation measures (EAEC, 2002sss). The analysis shows the cost effectiveness for the above mitigation measures ranges from $4,000 to as high as $280,000 per ton of NO_x or PM_{10} reduced. Of the above mitigation measures, the measures that are most cost effective and which have the greatest potential for emission reductions are the replacement of wood stoves ($3,900 per ton), the retrofit of fireplaces with gas logs ($7,500 per ton), and the retrofit/replacement of heavy-duty engines ($13,000 per ton).

STAFF RECOMMENDED ADDITIONAL MITIGATION

CONSTRUCTION PHASE

To adequately mitigate the remaining significant impacts associated with project and linear construction, staff is proposing a number of Conditions of Certification (**AQ-SC1** through **AQ-SC4**). These conditions include requirement for the identification of a Compliance Mitigation Manager who will be responsible for enforcement of construction mitigation measures. The recommended mitigation measures include that the applicant submit a comprehensive Fugitive Dust Mitigation plan, the submittal of monthly compliance reports, the use of catalyzed diesel particulate filters on construction equipment, the use of ultra low sulfur diesel fuel for that equipment, the use of newer equipment that meets the EPA and/or CARB 1996 or better off-road equipment emission standards, and limiting diesel engine idle time to no more that 10 minutes.

Staff believes that, with the implementation of these mitigation measures and the compliance responsibilities for monitoring by the Compliance Mitigation Manager, any remaining project and linear construction related impacts would be reduced to a level of insignificance.

OPERATION PHASE

While the applicant has provided emission reduction credits (ERCs) sufficient to satisfy the Bay Area District rules and regulations (see District Final Determination of Compliance), the ERCs do not, in staff's opinion, fully mitigate the project PM_{10} and ozone impacts to the local area. Staff believes that the applicant needs to provide additional local ozone precursor reductions and PM_{10} emission reductions to mitigate the project impacts to a level of less than significant. As mentioned earlier, staff recommends that additional local emission reductions equal to 175 tpy of ozone precursors (NO_x and/or VOC), and 50 tpy of PM_{10} emission reductions be secured in the Tracy/Livermore area (see **AIR QUALITY Table 8**) to mitigate the project. These emissions reductions would be in addition to those required by BAAQMD rules.

Staff evaluated the information provided by the applicant in their "consensus" proposal and found that the most cost effective measures contained in that proposal that also have the potential to provide sufficient emission reductions were the heavy duty engine retrofit/replacement program and the wood stove replacement program (EAEC, 2002sss). Staff recommends that a combination of wood stove replacements and heavy-duty engine retrofit/replacements be implemented to achieve the emission reductions in the local area. Below is staff's detailed discussion of the recommended mitigation measures.

Additional Ozone Precursors (NO_x and/or VOC) Mitigation

The SJVAPCD currently sponsors a program called the "Heavy-Duty Engine Incentive Program," which provides financial incentives to any individual or business to purchase new engines or retrofit existing units that would lower emissions. Under this program, the SJVAPCD provides a maximum $13,000 for each ton of NO_x emissions reduced. According to the SJVAPCD, from its start in 1997 to June, 2002, the program has achieved approximately 22,450 tons of NO_x emission reductions from a combination of engine retrofits and engine replacements, totaling approximately 3,466 engines. Most of these engines are in agricultural services, with some engines used off-road (such as construction equipment), and some on-road vehicle applications. The lifetime for each engine funded through the Engine Incentive Program varies from 7 to 12 years depending the application, and the average lifetime is 7.7 years (SJVAPCD's 2002 and 2005 Rate of Progress Plan, May 2002).

Staff recommends, as the preferred mitigation option, that the applicant provide funding to SJVAPCD to continue and expand this program. The only restriction that staff recommends would be that the funding only be used for applications that would result in emission reductions in the Livermore/Tracy and northern San Joaquin Valley areas.

Because the engine incentive program can generate emission reductions that only have an average 7.7 years lifespan, while the proposed project could last up to 40 years, staff estimated the number of participating engines necessary to ensure mitigation for the entire project life. To do so, staff estimated the entire project's NO_x and VOC emission (shortfall) liability, and then estimated the potential emission reductions for each engine. The project's NO_x and VOC shortfall has been estimated above to be 175 tpy multiplied by 40 years, which is 7,000 tons for the entire project life.

Using the SJVAPCD's estimated emission reductions of 22,450 tons for 3,466 engine applications, staff estimates that each engine would generate about 6.5 tons of NO_x emission reduction credits over its lifetime (7.7 years life). Thus, 1,080 engines need to be retrofitted (or replaced) to mitigate the project's lifetime NOx and/or VOC liability of 7,000 tons.

Staff recommends that the applicant provide enough funding to the SJVAPCD to support retrofit/replacement of 1,080 engines over four consecutive 8 year-phases. Altogether, this mitigation measure would provide 7,000 tons of NO_x emission reductions, which would provide continuing mitigation for the lifetime of the EAEC. **AIR QUALITY Table 9** summarizes staff's findings and recommendations for the additional mitigation measures.

Additional PM_{10} Mitigation

The SJVAPCD has not published the estimated PM_{10} emission reductions for the engine incentive program; however, the applicant has provided some information from the SJVAPCD and estimates that the heavy-duty engine incentive program can generate up to 53 lbs each year for each participating engine (EAEC, 2002sss).

Using the applicant's information, staff estimates that approximately 57,240 pounds per year (29 tpy) of PM_{10} emission reductions can be generated from retrofitting/replacement of 1,080 heavy-duty engines. This amount of emission reductions would reduce the project PM_{10} emissions liability to 21 tpy.

Taking into account that the area typically experiences violations of the PM_{10} standard only during the four winter months (November to February), staff recommends that only the four month portion of the project's remaining PM_{10} emissions liability (21 tpy) be mitigated with additional local PM_{10} emission reductions.

Using this approach, staff estimates that the project's remaining PM_{10} emissions liability that needs to be mitigated is [(4/12)x21 tpy], or 7 tons of PM_{10} per PM_{10} season.

To mitigate the project's remaining PM_{10} emissions, staff recommends that the applicant develop a plan to provide financial incentives to willing participants in the Livermore/Tracy area to replace their current conventional wood stoves with newer, cleaner units. Under this program, each participant would receive a cash rebate of $1,250 to replace his or her current wood stove with a newer, EPA certified unit. [This program is currently being offered in another project (Three Mountain Power Plant) and is very successful]. Staff estimates that the program should provide enough funds (approximately $490,000) to subsidize 395 units. Staff estimates that this program would generate 7 tons of PM_{10} per PM_{10} season to mitigate the remaining PM_{10} emission liability for the project (see **AIR QUALITY Table 9**).

AIR QUALITY Table 9
Project's Emissions and Staff Recommended Additional Mitigation

	NO_X and/or VOC	**PM_{10}**
Annual Project Emission Liability	175 tons per year	50 tons per year
Lifetime Project Emission Liability (for 40 years)	7,000 tons	not calculated
Heavy-Duty Engine Incentives Program		
Phase 1 (2002-2010) – 270 engines	1,725 tons	29 tons per year
Phase 2 (2011-2018) – 270 engines	1,725 tons	29 tons per year
Phase 3 (2019-2026) – 270 engines	1,725 tons	29 tons per year
Phase 4 (2027-2034) – 270 engines	1,725 tons	29 tons per year
Total for all 4 phases – 1,080 engines	7,000 tons	
Remaining Project Liability	0	21 tons per year, 7 tons per PM_{10} season
Wood Stove Replacement Program – 395 units	Not calculated	7 tons per PM_{10} season
Adequate to mitigate project's emissions?	Yes	Yes

Note: [1] N/C means not calculated

Additional SO_x and Secondary PM_{10} Mitigation

In addition to the Wood Stove Replacement program, staff also recommends that ultra low sulfur diesel fuel, which contains no more than 15 ppm sulfur content be used to fuel the operation of the fire pump diesel engine. Because the operation of the fire pump engine is sporadic, staff has not estimated its SO_x emissions. However, the operation of the engine with ultra low sulfur diesel fuel would result in 97 percent SO_x emission reduction compared with standard diesel fuel (which contains up to 500 ppm sulfur) each and every time the engine is in operation. [This ultra low sulfur fuel is already proposed to be used in the construction of the facility]. Staff believes that the slight different cost between the ultra low sulfur diesel and the standard diesel would be a feasible control measure to reduce sulfur oxides emissions, and secondary PM_{10} emissions that the fire pump diesel engine produced.

What if neither program works?

Staff believes that the implementation of both programs above would generate enough ozone precursors and PM_{10} emission reductions to mitigate the project's local contribution to the area's ozone and PM_{10} violations. However, for numerous reasons, there is the potential that participation in the engine and woodstove replacement programs could be insufficient, resulting in emission reduction shortfalls.

For example, the continuity of the engine replacement program could be complicated by the fact that the State Air Resources Board has already issued regulations that affect the emissions of heavy-duty engines (on- or off-road) as soon as 2004. These regulations may affect the availability of qualified engines as newer, cleaner engines would not be able to participate in the replacement/retrofit program.

The woodstove program relies on private consumers deciding that the subsidy is adequate to proceed with a "home remodeling." These remodeling decisions are subject to arbitrary and volatile factors such as housing prices and home equity, the state of the economy, and consumer confidence. Participation in the woodstove replacement program therefore cannot be guaranteed.

The applicant could also acquire Emission Reduction Credits (ERCs) to make up emission reduction shortfalls due to insufficient engine and woodstove replacement participation. Alternatively, the applicant could choose to secure all the necessary emission reductions in the form of credits. The SJVAPCD has offset banks split into three regions: the North, Central and Southern regions. If the applicant were to secure ERCs in lieu of or in combination with staff's proposed mitigation programs, staff recommends that the applicant acquire NO_x, VOC, and PM_{10} emission reduction credits,in the North Region of the SJVAPCD. Staff believes that ERCs from North Region of SJVAPCD, equal to the amount specified in **AIR QUALITY Table 9**, would be closest to the proposed project and to the areas of potential impacts.

Staff believes that there are adequate ERCs available in the SJVAPCD offset bank to fully mitigate the project's NO_x, VOC and PM_{10} emissions. From the standpoint of flexibility, the applicant could agree to any combination of actual emission reductions from the replacement programs in the northern San Joaquin valley and the acquisition of ERCs as long as the quantities equal the amounts shown as necessary in **AIR QUALITY Table 9.**

In summary, staff believes that the project's potential air quality impacts can be adequately mitigated through the use of controlling emissions from existing sources (i.e., engines and woodstoves) and/or the use of ERCs acquired from the SJVAPCD offset bank. Staff would prefer that all feasible actual emission reduction scenarios be explored first and that when those scenarios are exhausted or are not deemed feasible, then any remaining emissions shortfall be met through the acquisition of ERCs from the SJVAPCD offset bank.

WHAT IF THE EAEC PROJECT WAS SUBJECT TO SJVAPCD RULES?

As noted in the **SETTING** section, the proposed project site is located in the northeast corner of Alameda County on the east side of the Altamont Pass, and is subject to the jurisdiction of the Bay Area Air Quality Management District.   However, due to local topography, the proposed site and project emissions would be located in the San Joaquin Valley air shed, which is subject to oversight by the SJVAPCD (jurisdiction begins at the San Joaquin County line, a mile east of the project site). As such, the project emissions would affect the air quality in the San Joaquin Valley, especially the northern portion of the air basin, due to its unique location. The air quality in the San Joaquin Valley is worse than the air quality in the Bay Area. That is why the SJVAPCD offset requirements are stricter than those of the Bay Area District. [The stricter offset requirements are intended to ensure that the SJVAPCD can achieve progress toward its attainment goal.]

To demonstrate that staff's proposed mitigation is appropriate and reasonable for the proposed location of the project, staff developed a scenario wherein the proposed project is subject to the rules of SJVAPCD, the region most affected by the project and its emissions. Staff then compared those SJVAPCD offset requirements with the Staff additional mitigation proposed above. Staff evaluated the offset requirements for the EAEC project using SJVAPCD Rule 2201 - New and Modified Stationary Source Review. The evaluation included the offset threshold and used the following offset ratios:

1.2:1 for emission reductions that are within 15 miles of the proposed project site, and

1.5:1 for those reductions that are outside of the 15 miles radius, including those offsets in BAAQMD.

Additionally, the ERCs from the BAAQMD west of Altamont Pass were valued at a 27 percent effectiveness to offset San Joaquin Valley projects and emissions (per CARB and SJVAPCD).

As shown in **AIR QUALITY Table 10**, if the project were subject to the jurisdiction of the SJVAPCD, the applicant would need to provide an additional 216 tpy of NO_x and VOC as ozone precursors reductions and an additional 95 tpy of PM_{10} reductions. These additional emission reductions are similar, but greater than what staff is proposing (175 tpy of ozone precursor and 50 tpy of PM_{10} emission reductions) in order to mitigate the impacts of the project's emissions in the San Joaquin Valley. The differences stem from staff valuing those BAAQMD credits from Antioch for NO_x and SO_x at 70 percent effectiveness, while staff assumed that the SJVAPCD would value all credits west of Altamont Pass, including those in Antioch, at 27 percent effectiveness (see **AIR QUALITY Table 8**). Additionally, some of differences are due to the relative stringency of the SJVAPCD rules compared to BAAQMD due to the poor San Joaquin Valley regional air quality and limited progress towards attainment, and the SJVAPCD Rule 2201 Offset Threshold.

AIR QUALITY Table 10
EAEC Project per SJVAPCD Rules and w/BAAQMD ERCs

	VOC	NO_x	PM_{10}	SO_x
EAEC Project Emissions (tpy)	73.7	263	148.0	24
SJVAPCD Rule 2201 Offset Threshold (tpy)	10	10	14.6	27.4
SJVAPCD Offsets required	63.7	253	133.4	0.0
BAAQMD ERCs	116.7	306.4	0.7	482.8
Transport ratio (CARB's and SJVAPCD's 27%)	3.7	3.7	3.7	3.7
SJVAPCD Distance ratio	1.5	1.5	1.5	1.5
Combined ratio (per SJVAPCD)	4.2	4.2	4.2	4.2
Value of BAAQMD ERCs (@ combined ratio of 4.2:1)	27.8	72.9	0.2	115.0
Net surplus (shortfall) (tpy)	-35.9	-180.1	-133.2	115.0
SOX for PM10 (@ interpollutant trading ratio of 3.0:1)			38.3	
Total ozone precursor shortfall (tpy)	-216			
Net surplus (shortfall) (tpy)	**-216**		**-94.9**	**0**

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. Since all project impacts would be mitigated to less than significance if staff's recommended mitigation measures are implemented, there is no environmental justice issue.

RESPONSE TO PUBLIC AND AGENCY COMMENTS

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 mayaffect 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 NO_x, VOC and local PM_{10} and SO_2 emission reduction credits.

MS-6 *The PSA has pointed out that Calpine is not proposing BACT air emissions controls for the plant. Again, unconscionable in an area with severe air quality problems to begin with. In addition to air pollution impacts on the San Joaquin Valley, this will add to the air pollution problems in the downwind Sierra Nevada Mountain region.*

Response: Even though Calpine is not proposed to operate the facility with emission limits that are comparable with BACT, the staff of the Bay Area Air Quality Management District and staff recommend that the facility would operate at levels comparable to BACT. These recommendations include a 2 ppm NO_x emission concentration, 5 ppm ammonia slip, and an oxidation catalyst.

EG-2 *Calpine will pollute our local area while the San Joaquin Pollution people will spend our mitigation money in Bakersfield. They already screwed us with the Peaker Plant. How many of these plants are we going to get. Offsetting their pollution with credits from industries shut down 10 years ago doesn't help no matter where the ERC's are located. The SJVAPCD is selling out Tracy once again.*

Response: As presented in the Staff Recommended Additional Mitigation, staff has made recommendations that additional mitigation measures be implemented to generate actual emission reductions in the local area. Staff believes that these emission reductions would mitigate the project's impacts to the air quality in the area.

EIH-1 *I am offended that Calpine has reneged on their promise to mitigate the impact of their plant on the citizens of Tracy. They now propose to give the funds to the Pollution Control District. I do not trust the Pollution Control District to use the funds for our protection.*

Their actions on the GWF project proves my theory. Every indication from their efforts on this project show their poor judgment.

Response: Staff is not aware that Calpine has made any promise to mitigate the project's impacts in Tracy area. Regardless of their promise, staff believes that the implementation of staff recommended additional mitigation (see above) would mitigate the project's impacts to a level of less than significant.

PS-1 *It's ironic that the San Joaquin Valley Air Pollution Control District is asking for money to mitigate EAEC Pollution because the emission reduction credits are up to 60 miles away from the plant site. The ERC's provided by the SJVAPCD to* *mitigate the Tracy Peaker Plants emissions were predominately 200 miles away. The San Joaquin Pollution District will sell out the citizens of Tracy out just like they did in the Tracy Peaker Plant. They will probably spend the $965,000 to fix up their office in Fresno. I attended the EAEC Workshop in Tracy and found the District representative to be very arrogant. Didn't he realize that without the CEC staff the district would receive no mitigation. The only local mitigation we got from GWF was through our own citizens negotiating. Calpine is using the Pollution Control District to ruin any real local air quality mitigation that the CEC might force them to provide. They are just trying to avoid their obligation to offset their local emissions in the Tracy area. Deny them their license.*

Response: Staff does not suggest criticism of the SJVAPCD or its staff. The District's mission and priority are slightly different from those of the Energy Commission. Energy Commission staff analyzes the development of the EAEC facility as a single project, while the District staff analyzes the project to fit the program, to ensure that it would comply with applicable laws, and to ensure that the project will not interfere with progress toward attainment for the whole area. Because of different goals and priorities, the District and the Commission staff seem to ask the applicant different questions; however, we have the same goal of protecting the public at large.

PRB-1 *I respectfully request that the California Energy Commission require the Calpine Company (East Altamont project) to mitigate all of its air quality credits in Tracy. Allowing this company to clean up other areas of the San Joaquin Valley will do absolutely nothing to clean the air in our local Tracy. Ground level ozone is becoming an increasing health hazard that our community is having to endure.*

Please enforce the strictest mitigation possible to this business. It is my request that in our current grade of poor air quality, labeled "extreme" by the U.S. Environmental Protection Agency, that this project be denied.

Response: As mentioned earlier, staff has recommended the state-of-the-art control technology, and local mitigation measures be implemented to mitigate the project impacts.

CBJ-1, AKJ-1, JSS-1 *We forward three articles regarding health impacts by pollution in the valley to the Commission staff for review.*

Response: Staff thanks you for your articles. We have reviewed the articles and incorporated appropriate findings into staff recommendations for mitigation in Air Quality and Public Health of this report.

AGENCY COMMENTS

San Joaquin County Board of Supervisors comments that the project will create negative impacts on air quality in the local area, and that the proposed emission reduction credits, which the applicant acquired from the Bay Area, may not be sufficient to mitigate such impacts.

Response: Staff agrees with the San Joaquin Board of Supervisors comment, and has recommends mitigation measures to specifically address the proposed facility impacts to the local air quality. Staff recommended mitigation measures are discussed in detail in the Staff Recommended Additional Mitigation section.

COMPLIANCE WITH LORS

FEDERAL

The applicant has submitted to the District an application for the Federal PSD permit. The District issued a Final Determination of Compliance (FDOC) on July 24, 2002, which includes the demonstration of compliance with the federal PSD requirements. [However, the final PSD permit will not be issued until the applicant has demonstrated compliance with the Federal Endangered Species Act.] Staff has incorporated the District's recommended Conditions into the Final Staff Assessment.

In addition, the applicant is required to submit an application to the District for a significant revision to the existing 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.

STATE

As discussed earlier and summarized below, the project has the potential to cause significant ozone and particulate matter impacts. Staff cannot recommend licensing the project without implementation of staff's recommended local mitigation measures [heavy-duty engine incentives and replacement of wood stoves]. If these two recommendations are adopted, staff believes that the project impacts on ozone and PM_{10} would be mitigated to a level of less than significant.

LOCAL

The District has issued a FDOC (July 24, 2002), which states that the proposed project is expected to comply with all applicable District rules and regulations, and that offsets will be provided prior to the issuance of the project Authority to Construct permit.

CONCLUSIONS

1. The project has the potential to cause significant impacts to the state and federal 1-hour and the federal 8-hour ozone air quality standards in both the Bay Area and San Joaquin air basins.
2. The project has the potential to cause significant impacts to the state 24-hour PM10 and the federal 24-hour PM2.5 air quality standards in both the Bay Area and San Joaquin air basins.

3. The applicant proposed emission reduction credits are not adequate to mitigate the project's potential significant impacts to the state and the federal ozone, PM10 and PM2.5 air quality standards in the San Joaquin air basin.
4. The project's potential impacts to the area would be mitigated to a level of less than significant with the implementation of mitigation measures to secure emissions reductions locally equivalent to 175 tons per year of NOx and/or VOC, as ozone precursors, and 50 ton per year of PM10. Staff prefers that the reductions come from the SJVAPCD Heavy-Duty Engine Incentive and the proposed Wood Stove Replacement mitigation measures. Alternatively, a mixture of ERCs and engine and stove replacements equal, locally, to 175 tons per year of NOx and/or VOC, as ozone precursors, and 50 ton per year of PM10, would mitigate the project’s potential impacts.

RECOMMENDATIONS

Staff recommends the following mitigation measures:

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 in both the Bay Area and San Joaquin air basins. Staff recommends the inclusion of this limit in Condition **AQ-25**.

An agreement to operate the fire pump diesel engine with ultra low sulfur diesel fuel to lessen the potential impacts of the project on the area PM_{10} and $PM_{2.5}$ ambient air quality standard in both the Bay Area and San Joaquin air basins. Staff recommends the inclusion of this restriction in Condition **AQ-68**.

The District has provided a Final Determination of Compliance, of which staff has incorporated the conclusion and appropriate conditions into the FSA. The District recommended conditions are presented here as Conditions 1 through 75. Staff also recommends the inclusion of Conditions of Certification **AQ-SC1** through **AQ-SC4** to address the construction-related impacts in both the Bay Area and San Joaquin air basins.

To secure emissions reductions locally equivalent to 175 tons per year of NO_x and/or VOC, as ozone precursors, and 50 ton per year of PM10. the reductions shall come from the following:

An agreement to provide enough funding to the SJVAPCD to subsidize the District's existing "Heavy-Duty Engine Incentive Program" to provide a reduction of 175 tons of ozone precursors (NO_x and/or VOC) for each year of the project lifetime. Staff recommends the inclusion of Condition of Certification **AQ-SC5** to address this mitigation measure; **AND**.

An agreement to design and implement a program to rebate $1,250 to each participant who volunteers to replace his or her existing wood stove with a new EPA certified unit. Staff recommends the inclusion of Condition of Certification **AQ-SC6** to address this mitigation measure; **OR**

Alternatively, the applicant could provide the necessary emissions reductions in the form of ERCs.

STAFF PROPOSED CONDITIONS OF CERTIFICATION

AQ-SC1 The project owner shall submit the resume(s) of each individual proposed to fill the designated Air Quality Construction Mitigation Manager (AQAQCMM) position to the CEC Compliance Project Manager (CPM) for approval. One or more individuals may hold this position. The owner shall be responsible for funding the costs of the AQCMM, however the AQCMM shall be allowed to report directly to the CPM. The AQCMM shall preferably have a minimum of eight years experience as follows, however the CPM shall consider all resumes submitted regardless of experience:

five years construction experience as a subcontractor or general contractor.

An engineering degree or an additional five years construction experience.

one year construction project management experience.

two years air quality assessment experience.

The AQCMM shall be responsible for implementing all mitigation measures related to construction equipment combustion emissions, construction monitoring and enforcing the effectiveness of construction mitigation measures as outlined in Conditions of Certification **AQ-SC3** and **AQ-SC4**. The AQCMM shall be onsite during all construction activities, until no longer deemed necessary by the CPM. The AQCMM shall be granted access to all areas of the main and linear facility construction sites. The AQCMM shall have the authority to stop specific construction activities on either the main or the linear facility construction sites as specified in Condition **AQ-SC3** (3) below. The AQCMM may not be terminated prior to the cessation of construction activities unless approval is granted by the CPM.

Verification The project owner shall submit the AQCMM resume(s) to the CPM for approval at least 60 days prior to site mobilization.

AQ-SC2 The project owner shall ensure that the AQCMM submits directly to the CPM for approval (and a copy to the project owner) a report of all compliance actions taken germane to Conditions of Certification **AQ-SC3** and **AQ-SC4**. The report shall include, at a minimum, the following elements:

Fugitive Dust Mitigation Monthly Report
(see Condition of Certification AQ-SC3)

a) A summary of each of the operation(s) planned for the following two months which may result in the generation of fugitive dust. Each description shall include a schedule, on-site location details and a list of proposed fugitive dust mitigation measures.

b) A summary of all mitigation activities implemented for each fugitive dust generating operation identified in a previous report. This report should provide a summary description of the operation, the mitigation measures implemented and the estimated effectiveness of each mitigation measure.

c) Details of all operation(s) requiring fugitive dust mitigation that are not identified in the previous report or the FDMP. Details shall include (at a minimum) a description of the operation, the date, duration, mitigation measures implemented, and an explanation for not reporting the operation in a previous report (or in the FDMP).

d) Identification of any failures of mitigation measures and details of the actions taken to reduce the identified impacts and prevent future failures of those mitigation measures.

e) Identification of any observation by the AQCMM of dust plumes beyond the property boundary of the main construction site or beyond an acceptable distance from the linear construction site and what actions (if any) where taken to abate the plume.

f) A summary of all ambient air monitoring data collected.

Diesel Construction Equipment Mitigation Monthly Report (see Condition of Certification AQ-SC4)

a) Identification of any changes, as approved by the CPM, to the Diesel Construction Equipment Mitigation Plan from the initial report or the last monthly report including any new contractors and their diesel construction equipment.

b) A Copy of all receipts or other documentation indicating types and amounts of fuel purchased, from whom, where delivered and on what date for the main and related linear construction sites.

c) Identification and verification of all diesel engines required to meet EPA or CARB 1996 off-road diesel equipment emission standards.

d) The suitability of the use of a catalyzed diesel particulate filter for a specific piece of construction equipment is to be determined by a qualified mechanic or engineer who must submit a report through the AQCMM to the CPM for approval. The identification of any suitability report initiated or pursued, or the completed report, should be included in the monthly report (in the month that it was completed) as should the verification of any subsequent installation of a catalyzed diesel particulate filter.

e) Identification of any observation by the AQCMM of exhaust plumes emanating from diesel-fired construction equipment beyond the property boundary of the main construction site or beyond an acceptable distance from the linear construction site and what actions (if any) where taken to abate the plume or future expected plumes.

<u>Verification:</u> The project owner shall ensure that the AQCMM submits directly to the CPM for approval (and a copy to the project owner), in the MCR, all compliance actions taken germane to Conditions of Certification **AQ-SC3** and **AQ-SC4**. The report is due within ten working days after the end of each reporting month.

AQ-SC3 The project owner shall ensure that the AQCMM prepares and submits to the CPM for approval, a Fugitive Dust Mitigation Plan (FDMP) that specifically identifies all fugitive dust mitigation measures that will be employed during the construction of the facility and related linears. The FDMP shall be administered on site by the full-time AQCMM.

The FDMP shall include a schedule of each operation planned for the first two months of the project that may result in the generation of fugitive dust, including location, source(s) of fugitive dust, and proposed mitigation measures specific to each operation/source.

The construction mitigation measures that shall be addressed in the FDMP include, but are not limited to, the following:

Identification of the employee parking area(s) and surface composition of those parking area(s)

The frequency of watering of unpaved roads and all disturbed areas

Application of chemical dust suppressants

Gravel in high traffic areas

Paved access aprons

Sandbags to prevent run off

Posted speed limit signs

Wheel washing areas prior to large trucks leaving the project site

Methods that will be used to clean tracked-out mud and dirt from the project site onto public roads

For any transportation of solid bulk material

1. Vehicle covers
2. Wetting of the transported material
3. Appropriate freeboard

Methods for the stabilization of storage piles and disturbed areas

Windbreaks at appropriate locations

Additional mitigation measures to be implemented at the direction of the AQCMM in the event that the standard measures fail to completely control dust from any activity and/or source

The suspension of all earth moving activities under windy conditions

On-site monitoring devices

In monitoring the effectiveness of all mitigation measures included in the FDMP, the AQCMM shall take into account the following, at a minimum:

a) Onsite spot checks of soil moisture content at locations where soil disturbance, movement and/or storage is occurring; and
b) Visual observations of all construction activities.

The AQCMM shall implement the following procedures for additional mitigation measures if the AQCMM determines that the existing mitigation measures are not resulting in effective mitigation:

1) The AQCMM shall direct more aggressive application of the existing mitigation methods if standard mitigation measures are not effective.

2) The AQCMM shall direct implementation of additional methods of mitigation if step #1 specified above fails to result in adequate mitigation.

3) The AQCMM shall direct a temporary shutdown of the source of the emissions if step #2 specified above fails to result in adequate mitigation within one) hour of the original determination. The activity shall not restart until circumstances leading to the problem have been addressed.

Verification: At least 30 days prior to site mobilization, the project owner shall provide the CPM with a copy of the FDMP for approval. Site mobilization shall not commence until the project owner receives approval of the FDMP from the CPM.

AQ-SC4 The project owner shall ensure that the AQCMM prepares and submits to the CPM for approval, a Diesel Construction Equipment Mitigation Plan (DCEMP) that will specifically identify diesel engine mitigation measures that will be employed during the construction phase of the main and related linear construction sites. The project owner shall ensure that the AQCMM will be responsible for directing implementation of and compliance with all measures identified in the DCEMP. The DCEMP shall address, at a minimum, the following mitigation measures:

Catalyzed diesel particulate filters (CDPF)

CARB certified ultra low sulfur diesel fuel, containing 15ppm sulfur or less (ULSD)

Diesel engines certified to meet EPA and/or CARB 1996 or better off-road equipment emission standards

Restricting diesel engine idle time, to the extent practical, to no more than ten minutes

The DCEMP shall include the following:

1. A list of all diesel-fueled, off-road, stationary or portable construction-related equipment to be used either on the main or the related linear construction sites. This list will initially be estimated and then subsequently be updated as specific contractors become identified. Prior to a contractor gaining access to the main or related linear construction sites, the project owner shall ensure that the AQCMM submits to the CPM for approval, an update of this list including all of the new contractor's diesel construction equipment.

2. Each piece of construction equipment listed under item #1 of this condition must demonstrate compliance according to the following mitigation requirements, except as noted in items #3, #4 and #5 of this condition:

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

3. If the construction equipment is intended to be on-site for ten days or less, then none of the mitigation measures identified in item #2 of this condition are required.

4. The CPM may grant relief from the mitigation measures listed in item #2 of this condition for a specific piece of equipment if the AQCMM can demonstrate that they have made a good faith effort to comply with the mitigation measures and that compliance is not possible.

5. Any implemented mitigation measure in item #2 of this condition may be terminated immediately if one of the following conditions exists, however the CPM must be informed within ten working days of the termination:

    5.1 The measure is excessively reducing normal availability of the construction equipment due to increased downtime for maintenance, and/or reduced power output due to an excessive increase in back pressure.

    5.2 The measure is causing or is reasonably expected to cause significant engine damage.

    5.3 The measure is causing or is reasonably expected to cause a significant risk to workers or the public.

    5.4 Any other seriously detrimental cause which has approval by the CPM prior to the termination being implemented.

6. All contractors must agree to limit diesel engine idle time on all diesel-powered equipment to no more than ten minutes, to the extent practical.

Verification: The project owner shall ensure that the AQCMM submits a DCEMP to the CPM for approval at least 30 days prior to site mobilization. The AQCMM will update the initial DCEMP (if necessary), no less than ten days prior to a specific contractor gaining access to either the main or related linear construction sites. The project owner shall ensure that the AQCMM notifies the CPM of any emergency termination within ten working days of the termination.

AQ-SC5 The project owner shall provide emissions reductions locally equivalent to 175 tons per year of NO_x and/or VOC, as ozone precursors.

Protocol: The project owner shall provide funds to the San Joaquin Valley Air Pollution Control District (SJVAPCD) to support its "Heavy-Duty Engine Incentive

Program." The funds shall be distributed to the SJVAPCD in four phases according to the following schedule:

(a) The first payment shall begin immediately after the project receives an Authority to Construct from the Bay Area Air Quality Management District. The fund shall be in sufficient quantity, plus five percent for administration costs, to finance new purchases, engine re-power, or retrofit qualified engines to generate 1,725 tons (based on 7.7 years lifetime) of NO_x and/or VOC emission reduction credits combined.

(b) The second payment shall begin in 2011. The fund shall be in sufficient quantity, plus five percent for administration costs, to finance new purchases, engine re-power, or retrofit qualified engines to generate 1,725 tons (based on 7.7 years lifetime) of NO_x and/or VOC emission reduction credits combined.

(c) The third payment shall begin in 2019. The fund shall be in sufficient quantity, plus five percent for administration costs, to finance new purchases, engine re-power, or retrofit qualified engines to generate 1,725 tons (based on 7.7 years lifetime) of NO_x and/or VOC emission reduction credits combined.

(d) The fourth payment shall begin in 2027. The fund shall be in sufficient quantity, plus five percent for administration costs, to finance new purchases, engine re-power, or retrofit qualified engines to generate 1,725 tons (based on 7.7 years lifetime) of NO_x and/or VOC emission reduction credits combined.

Funding for Phase 2, 3, or 4 to the SJVAPCD "Heavy-Duty Engine Incentive Program" shall be terminated if the program fails to achieve the necessary Phase I NO_x and/or VOC emission reduction credits specified above. In such case, or if the applicant chooses to purchase and provide emission reduction credits, or initiate other programs approved by the Commission staff to benefit the Air Quality in the Tracy/Livermore area, the reductions must be equivalent to 175 tpy of NO_x and/or VOC, combined,

"Qualified engine" means any internal combustion engine that meets the requirement specified in the current SJVAPCD "Heavy-Duty Engine Incentive Program", and has an operating base in the San Joaquin County or East of Interstate Highway 680 in Alameda County.

Verification: The project owner, in the annual report, shall provide the CPM information detailing the tons of emission reductions of NO_x and VOC secured from EAEC funding of the SJVAPCD "Heavy-Duty Engine Incentive Program," the purchase of emission reduction credits, or from other programs approved by the Commission staff to benefit the Air Quality in the Tracy/Livermore area. The reports shall contain, but not be limited to the number and types of qualified participating engines, the amount of NO_x and/or VOC emission reduction credits for each engine, the running total emission reduction credits secured and surrendered, and the operational location of these engines, the location of emission reductions, and/or the status emission reduction programs. The emissions reductions must be equivalent to 175 tpy of NO_x and/or VOC, combined.

AQ-SC6 The project owner shall provide emissions reductions locally equivalent to 50 tons per year of PM10.

Protocol: The project owner shall submit a plan for a fireplace retrofit/woodstove replacement program to the CPM for approval. The plan shall provide the following elements:

a) Provisions for a replacement fund to be made available on a first-come, first-serve basis to finance a five-year voluntary woodstove replacement/fireplace retrofit program which shall provide a minimum PM_{10} emission reductions of 7 tons/PM10 season. The replacement fund shall pay for the retrofit/ replacement costs of at least 395 current non-EPA certified fireplaces and woodstoves (up to a maximum of $1,250 for each retrofit/replacement) with an EPA-certified solid fuel heating device. The fund shall be capable of being drawn upon in any year of the five year program and as allowed by conditions of certification until the fund is depleted.

b) A procedure whereby the CPM would establish a list of approved retailers and professional, licensed installers. Each resident participating in the retrofit/replacement program would only do business with listed retailers or installers. Payments shall only be made to vendors or contractors who agree to participate in the program and who submit certification that the retrofit/replacement is permanent (by permanent removal of the wood stove doors and proper recycling of the old stove) and conforms to program requirements.

c) Submission to the CPM of quarterly status reports on the program, the status of reimbursements, and remaining funds available. In addition, the fund shall be audited annually.

d) A description of eligibility requirements, including that, for the first three years of the program, homes and businesses located within a fifteen-mile radius of the proposed facility will be eligible to participate in the program. Homes and businesses within a twenty five-mile radius of the EAEC facility would be eligible to participate in the fourth and fifth years if there are remaining funds.

If the program fails to achieve the necessary PM10 emission reduction specified above and the applicant chooses to purchase and provide emission reduction credits or initiate other programs approved by the CPM to benefit the Air Quality in the Tracy/Livermore area, the emission reductions provided by the project owner must be equivalent to 50 tpy of PM10.

Verification: No later than 30 days prior to commencement of construction, the project owner shall provide the CPM, for approval, a copy of the wood stove replacement program or a PM10 emission reduction program(s) designed to secure 50 tpy of PM10. The project owner shall surrender PM10 emission reductions and/or ERCs to the CPM within 60 days of securing the emission reduction or ERC. The project owner shall submit to the CPM a copy of the quarterly report within 45 days of the end of each quarter detailing the PM10 emission reductions, the method used to secure, and the emission reductions and/or ERCs surrendered to the CPM. The 4th quarter report shall contain an annual summary.

AQ-SC7 The project owner shall submit to the CPM for review and approval any modification proposed by either the project owner or issuing agency to any project air permit.

<u>Verification:</u> The project owner shall submit any proposed air permit modification to the CPM within five working days of its submittal either by 1) the project owner to an agency, or 2) receipt of proposed modifications from an agency. The project owner shall submit all modified air permits to the CPM within 15 days of receipt.

DISTRICT'S CONDITIONS OF CERTIFICATION

(A) Definitions:

Clock Hour:	Any continuous 60-minute period beginning on the hour
Calendar Day:	Any continuous 24-hour period beginning at 12:00 AM or 0000 hours
Year:	Any consecutive twelve-month period of time
Heat Input:	All heat inputs refer to the heat input at the higher heating value (HHV) of the fuel, in BTU/scf
Rolling 3-hour period:	Any consecutive three-hour period, not including start-up or shutdown periods
Firing Hours:	Period of time during which fuel is flowing to a unit, measured in minutes
MM BTU:	million british thermal units
Gas Turbine Start-up Mode:	The lesser of the first 180 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 25(b) and 25(d)
Gas Turbine Shutdown Mode:	The lesser of the 30 minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 25(b) through 25(d) until termination of fuel flow to the Gas Turbine
Specified PAHs:	The polycyclic aromatic hydrocarbons listed below shall be considered to be Specified PAHs for these permit conditions. Any emission limits for Specified PAHs refer to the sum of the emissions for all six of the following compounds Benzo[a]anthracene Benzo[b]fluoranthene Benzo[k]fluoranthene Benzo[a]pyrene

Dibenzo[a,h]anthracene

Indeno[1,2,3-cd]pyrene

Corrected Concentration:	The concentration of any pollutant (generally NO_x, CO, or NH_3) corrected to a standard stack gas oxygen concentration. For emission points P-1 (combined exhaust of S-1 Gas Turbine and S-2 HRSG duct burner) P-2 (combined exhaust of S-3 Gas Turbine and S-4 HRSG duct burner), and P-3 (combined exhaust of S-5 Gas Turbine and S-6 HRSG duct burner), the standard stack gas oxygen concentration is 15% O_2 by volume on a dry basis. For emission point P-4 (auxiliary boiler), the standard stack gas oxygen concentration is 3% O_2 by volume on a dry basis
Commissioning Activities:	All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the EAEC construction contractor to insure safe and reliable steady state operation of the gas turbines, heat recovery steam generators, steam turbine, and associated electrical delivery systems
Commissioning Period:	The Period shall commence when all mechanical, electrical, and control systems are installed and individual system start-up has been completed, or when a gas turbine is first fired, whichever occurs first. The period shall terminate when the plant has successfully completed both performance and compliance testing. The commissioning period shall not exceed 180 days under any circumstances.
Precursor Organic Compounds (POCs):	Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate
CEC CPM:	California Energy Commission Compliance Program Manager
EAEC:	East Altamont Energy Center

(B) Applicability:

Conditions 1 through 16 and their verifications shall only apply during the commissioning period as defined above. Unless otherwise indicated, Conditions 17 through 74 shall apply after the commissioning period has ended.

Conditions for the Commissioning Period

AQ-1 The project owner of the East Altamont Energy Center (EAEC) shall minimize emissions of carbon monoxide and nitrogen oxides from S-1, S-3, and S-5 Gas Turbines and S-2, S-4, and S-6 Heat Recovery Steam Generators (HRSGs) to the maximum extent possible during the commissioning period.

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-2 At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the project owner shall **tune** the S-1, S-3, & S-5 Gas Turbine combustors and S-2, S-4, & S-6 Heat Recovery Steam Generator duct burners to minimize the emissions of carbon monoxide and nitrogen oxides.

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-3 At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the project owner shall install, **adjust**, and operate the A-1, A-3, A-5, & A-7 Oxidation Catalysts and A-2, A-4, A-6, & A-8 SCR Systems to minimize the emissions of carbon monoxide and nitrogen oxides from S-1, S-3, & S-5 Gas Turbines, S-2, S-4, & S-6 Heat Recovery Steam Generators, and S-7 Auxiliary Boiler.

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-4 Coincident with the steady-state operation of A-2, A-4, & A-6 SCR Systems and A-1, A-3, A-5, & A-7 Oxidation Catalysts pursuant to conditions 3, 9, 10, and 11, the **project owner** shall operate the Gas Turbines (S-1, S-3, & S-5) and the HRSGs (S-2, S-4, & S-6) in such a manner as to comply with the NO_x and CO emission limitations specified in conditions 25(a) through 25(d).

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-5 Coincident with the steady-state operation of the A-8 SCR Systems and A-7 Oxidation **Catalyst pursuant** to conditions 3 and 12, the project owner shall operate the S-7 Auxiliary Boiler in such a manner as to comply with the NO_x and CO emission limitations specified in conditions 33(a) through 33(d).

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-6 The project owner of the EAEC shall submit a plan to the District Permit Services Division and the CEC CPM at least four weeks prior to first firing of S-1, S-3, or S-5 Gas Turbines describing the procedures to be followed during the commissioning of the turbines, HRSGs, auxiliary boiler, and steam turbine. 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 required emission control systems, the installation, calibration, and testing of the CO and NO_x continuous emission monitors, and any activities requiring the firing of the Gas Turbines (S-1, S-3, & S-5), HRSGs (S-2, S-4, & S-6), and S-7 Auxiliary Boiler without abatement by their respective Oxidation Catalysts and/or SCR Systems. The project owner shall not fire any of the Gas Turbines (S-1, S-3, or S-5) sooner than 28 days after the District receives the commissioning plan.

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-7 During the commissioning period, the project owner of the EAEC shall demonstrate **compliance** with conditions 13, 14, and 15 through the use of **properly** operated and maintained continuous emission monitors and data recorders for the following parameters:

firing hours

fuel flow rates

stack gas nitrogen oxide emission concentrations,

stack gas carbon monoxide emission concentrations

stack gas oxygen 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 (S-1, S-3, & S-5), HRSGs (S-2, S-4, & S-6), and S-7 Auxiliary Boiler. The project owner shall use District-approved methods to calculate heat input rates, nitrogen dioxide mass emission rates, carbon monoxide mass emission rates, and NO_x and CO emission concentrations, summarized for each clock hour and each calendar day. The project owner shall retain records on site for at least 5 years from the date of entry and make such records available to District personnel upon request.

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-8 The project owner shall install, calibrate, and operate the District-approved continuous monitors specified in condition 7 prior to first firing of the Gas Turbines (S-1, S-3, & S-5), Heat Recovery Steam Generators (S-2, S-4, & S-6), and S-7 Auxiliary Boiler. **After** first firing of the turbines and/or auxiliary boiler, the project owner shall adjust the detection range of these continuous emission monitors as necessary to accurately measure the resulting range of CO and NO_x emission concentrations. The type, specifications, and location of these monitors shall be subject to District review and approval.

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.. In addition, the project owner shall provide evidence of the District's approval of the emission monitoring system to the CPM prior to first firing of the gas turbines.

AQ-9 The project owner shall not fire the S-1 Gas Turbine and S-2 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-1 SCR System and/or abatement of carbon monoxide emissions by A-1 Oxidation Catalyst for more than 300 hours during the commissioning period. Such operation of S-1 Gas Turbine and S-2 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and/or oxidation catalyst in place. Upon completion of these activities, the project owner shall provide written notice to the District Permit

Services and Enforcement Divisions, and the CPM, and the unused balance of the 300 firing hours without abatement shall expire.

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-10 The project owner shall not fire the S-3 Gas Turbine and S-4 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-3 SCR System and/or abatement of carbon monoxide emissions by A-3 Oxidation Catalyst for more than 300 hours during the commissioning period. Such operation of S-3 Gas Turbine and S-4 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and/or oxidation catalyst in place. Upon completion of these activities, the project owner shall provide written notice to the District Permit Services and Enforcement Divisions, and the CPM, and the unused balance of the 300 firing hours without abatement shall expire.

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-11 The project owner shall not fire the S-5 Gas Turbine and S-6 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-5 SCR System and/or abatement of carbon monoxide emissions by A-5 Oxidation Catalyst for more than 300 hours during the commissioning period. Such operation of S-5 Gas Turbine and S-6 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and/or oxidation catalyst in place. Upon completion of these activities, the project owner shall provide written notice to the District Permit Services and Enforcement Divisions, and the CPM, and the unused balance of the 300 firing hours without abatement shall expire.

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-12 The project owner shall not fire the S-7 Auxiliary Boiler without abatement of carbon monoxide emissions by A-7 Oxidation Catalyst and/or abatement of nitrogen oxide emissions by A-8 SCR System for more than 100 hours during the commissioning period. Such operation of S-7 Auxiliary Boiler without abatement by A-7 and/or A-8 shall be limited to discrete commissioning activities that can only be properly executed **without** the SCR system and/or oxidation catalyst in place. Upon completion of these activities, the project owner shall provide written notice to the District Permit Services and Enforcement Divisions, and the CPM, and the unused balance of the 100 firing hours without abatement shall expire.

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-13 The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, PM_{10}, and sulfur dioxide that are emitted by the Gas Turbines (S-1, S-3, & S-5), **Heat** Recovery Steam Generators (S-2, S-4, & S-6), S-7 Auxiliary Boiler, S-9 Fire Pump Diesel Engine, and S-10 Emergency

Generator during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in condition 35.

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-14 The project owner shall not operate the Gas Turbines (S-1, S-3, & S-5) and Heat Recovery Steam Generators (S-2, S-4, & S-6) in a manner such that the combined pollutant **emissions** from these sources will exceed the following limits during the commissioning period. These emission limits shall include emissions resulting from the start-up and shutdown of the Gas Turbines (S-1, S-3, & S-5).

NO_x (as NO_2)	4,805 pounds per calendar day	381 pounds per hour
CO	11,498 pounds per calendar day	930 pounds per hour
POC (as CH_4)	495 pounds per calendar day	
PM_{10}	660 pounds per calendar day	
SO_2	42 pounds per calendar day	

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with.

AQ-15 The project owner shall not operate the S-7 Auxiliary Boiler such that the pollutant emissions will exceed the following limits during the commissioning period. These emission limits shall include emissions that occur during Auxiliary Boiler start-ups.

NO_x (as NO_2)	428 pounds per calendar day	33 pounds per hour
CO	368 pounds per calendar day	22 pounds per hour
POC (as CH_4)	25.4 pounds per calendar day	
PM_{10}	96 pounds per calendar day	
SO_2	12.4 pounds per calendar day	

Verification: The project owner shall submit in the monthly compliance report to the CPM how this condition is being complied with..

AQ-16 Prior to the end of the Commissioning Period, the project owner shall conduct a District and CEC approved source test using external continuous emission monitors to determine compliance with the limitations specified in condition 26. 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. Twenty working days before the execution 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 CEC 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 CEC CPM within seven (7) working days prior to the planned source testing date. Source test results shall be submitted to the District and the CEC CPM within 60 days of the source testing date.

Verification: No later than 35 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 90 days of the source testing date.

Conditions for the Gas Turbines (S-1, S-3, & S-5) and the Heat Recovery Steam Generators (HRSGs; S-2, S-4, & S-6) for the Period Following Commissioning

AQ-17 The project owner shall fire the Gas Turbines (S-1, S-3, and S-5) and HRSG Duct Burners (S-2, S-4, and S-6) exclusively with natural gas. (BACT for SO_2 and PM_{10})

Verification: The project owner shall complete, on a daily basis, a laboratory analysis showing the sulfur content of natural gas being burned at the facility. The daily sulfur analysis reports shall be incorporated into the quarterly compliance reports.

AQ-18 The project owner shall not operate the units such that the combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2, S-3 & S-4, and S-5 & S-6) exceeds 2,630.8 MM BTU (HHV) per hour, averaged over any rolling 3-hour period. (PSD for NO_x)

Verification: As part of the quarterly and annual compliance reports, the project owner shall include information on the date, time, and duration of any violation of this permit condition.

AQ-19 The project owner shall not operate the units such that the combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2, S-3 & S-4, and S-5 & S-6) exceeds 63,139.2 MM BTU (HHV) per calendar day. (PSD for PM_{10})

Verification: As part of the quarterly and annual compliance reports, the project owner shall include information on the date, time, and duration of any violation of this permit condition.

AQ-20 The project owner shall not operate the units such that the combined cumulative heat input rate for the Gas Turbines (S-1, S-3, & S-5) and the HRSGs (S-2, S-4, & S-6) exceeds 61,100,064 MM BTU (HHV) per year. (Offsets)

Verification: As part of the quarterly and annual compliance reports, the project owner shall include information on the date, time, and duration of any violation of this permit condition.

AQ-21 The project owner shall not fire the HRSG duct burners (S-2, S-4, and S-6) unless its associated Gas Turbine (S-1, S-3, and S-5, respectively) is in operation. (BACT for NO_x)

Verification: As part of the quarterly and annual compliance reports, the project owner shall include information on the date, time, and duration of any violation of this permit condition.

AQ-22 The project owner shall ensure that the S-1 Gas Turbine and S-2 HRSG are abated by the properly operated and properly maintained A-2 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-2 SCR catalyst bed has reached minimum operating temperature. (BACT for NO_x)

Verification: As part of the quarterly and annual compliance reports, the project owner shall provide information on any major problem in the operation of the Oxidizing Catalyst and Selective Catalytic Reduction Systems for the Gas Turbines and HRSGs. The information shall include, at a minimum, the date and description of the problem and the steps taken to resolve the problem.

AQ-23 The project owner shall ensure that the S-3 Gas Turbine and S-4 HRSG are abated by the properly operated and properly maintained A-4 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-4 SCR catalyst bed has reached minimum operating temperature. (BACT for NO_x)

Verification: As part of the quarterly and annual compliance reports, the project owner shall provide information on any major problem in the operation of the Oxidizing Catalyst and Selective Catalytic Reduction Systems for the Gas Turbines and HRSGs. The information shall include, at a minimum, the date and description of the problem and the steps taken to resolve the problem.

AQ-24 The project owner shall ensure that the S-5 Gas Turbine and S-6 HRSG are abated by the properly operated and properly maintained A-6 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-6 SCR catalyst bed has reached minimum operating temperature. (BACT for NO_x)

Verification: As part of the quarterly and annual compliance reports, the project owner shall provide information on any major problem in the operation of the Oxidizing Catalyst and Selective Catalytic Reduction Systems for the Gas Turbines and HRSGs. The information shall include, at a minimum, the date and description of the problem and the steps taken to resolve the problem.

AQ-25 The project owner shall ensure that the Gas Turbines (S-1, S-3, & S-5) and HRSGs (S-2, S-4, & S-6) comply with requirements (a) through (h) under all operating scenarios, including duct burner firing mode and steam injection power augmentation mode. Requirements (a) through (h) do not apply during a gas turbine start-up or shutdown. (BACT, PSD, and Toxic Risk Management Policy)

(a) Nitrogen oxide mass emissions (calculated as NO_2) at P-1 (the combined exhaust point for S-1 Gas Turbine and S-2 HRSG after abatement by A-2

SCR System) shall not exceed 19 pounds per hour or 0.00723 lb/MM BTU (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated as NO_2) at P-2 (the combined exhaust point for S-3 Gas Turbine and S-4 HRSG after abatement by A-4 SCR System) shall not exceed 19 pounds per hour or 0.00723 lb/MM BTU (HHV) of natural gas fired.

Nitrogen oxide mass emissions (calculated as NO_2) at P-3 (the combined exhaust point for S-5 Gas Turbine and S-6 HRSG after abatement by A-6 SCR System) shall not exceed 19 pounds per hour or 0.00723 lb (HHV) of natural gas fired.

(PSD for NO_x)

(b) The nitrogen oxide emission concentration at emission points P-1, P-2, and P-3 each shall not exceed 2.0 ppmv, on a dry basis, corrected to 15% O_2, averaged over any 1-hour period. (BACT for NO_x)

(c) Carbon monoxide mass emissions at P-1, P-2, and P-3 each shall not exceed 23.15 pounds per hour or 0.0088 lb/MM BTU of natural gas fired, averaged over any rolling 3-hour period. (PSD for CO)

(d) The carbon monoxide emission concentration at P-1, P-2, and P-3 each shall not exceed 4.0 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. (BACT for CO)

(e) Ammonia (NH_3) emission concentrations at P-1, P-2, and P-3 each shall not exceed 5 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-2, A-4, and A-6 SCR Systems. The correlation between the gas turbine and HRSG heat input rates, A-2, A-4, and A-6 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-1, P-2, and P-3 shall be determined in accordance with permit condition 40. (TRMP for NH_3)

(f) Precursor organic compound (POC) mass emissions (as CH_4) at P-1, P-2, and P-3 each shall not exceed 6.64 pounds per hour or 0.00252 lb/MM BTU of natural gas fired. (BACT)

(g) Sulfur dioxide (SO_2) mass emissions at P-1, P-2, and P-3 each shall not exceed 1.84 pounds per hour or 0.0007 lb/MM BTU of natural gas fired. (BACT)

(h) Particulate matter (PM_{10}) mass emissions at P-1, P-2, and P-3 each shall not exceed 9 pounds per hour when the HRSG duct burners are not in operation. Particulate matter (PM_{10}) mass emissions at P-1, P-2, and P-3 each shall not exceed 11.5 pounds per hour when HRSG duct burners are in operation. (BACT)

(i) Compliance with the hourly NOx emission limitations specified in condition 25(a) and 25(b) shall not be required during short-term excursions limited to a cumulative total of 10 hours per rolling 12-month period. Short-term excursions are defined as 15-minute periods designated by the project owner that are the direct result of transient load conditions, not to exceed four consecutive 15-minute periods, when the 15-minute average NOx concentration exceeds 2.0 ppmv, dry @ 15% O_2. Examples of transient load conditions include, but are not limited to the following:

(1) Initiation/shutdown of combustion turbine inlet air cooling

(2) Initiation/shutdown of combustion turbine steam injection for power augmentation

(3) Rapid combustion turbine load changes

(4) Initiation/shutdown of HRSG duct burners

The maximum 1-hour average NOx concentration for periods that include short-term excursions shall not exceed 30 ppmv, dry @ 15% O_2. All emissions during short-term excursions shall be included in all calculations of hourly, daily, and annual mass emission rates as required by this permit.

Verification: The project owner shall submit to the District and CPM, quarterly reports for the proceeding calendar quarter within 30 days from the end of the quarter. The report for the fourth quarter can be an annual compliance summary for the preceding year. The quarterly and annual compliance summary reports shall contain the following information.

(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).

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.

AQ-26 The project owner shall ensure that the regulated air pollutant mass emission rates from each of the Gas Turbines (S-1, S-3, and S-5) during a start-up or a shutdown does not exceed the limits established below. (PSD)

	Start-Up (lb/start-up)	Shutdown (lb/shutdown)
Oxides of Nitrogen (as NO_2)	240	80
Carbon Monoxide (CO)	2,514	902
Precursor Organic Compounds (as CH_4)	48	1 16

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-27 No more than one Gas Turbine (S-1, S-3, or S-5) shall be in start-up mode at any point in time. (PSD).

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25 and report any instance in which more than one turbine has been in start-up mode.

Conditions for S-7 Auxiliary Boiler

AQ-28 The project owner shall fire the Auxiliary Boiler exclusively with natural gas. (BACT for SO_2 and PM_{10})

Verification: The project owner shall maintain, on a daily basis, a laboratory analysis showing the sulfur content of natural gas being burned at the facility. The daily sulfur analysis reports shall be incorporated into the quarterly compliance reports.

AQ-29 The project owner shall not operate the unit such that the heat input rate to S-7 Auxiliary Boiler exceeds 129 million BTU per hour, averaged over any rolling 3-hour period. (Cumulative Increase)

Verification: As part of the quarterly and annual compliance reports, the project owner shall include information on the date, time, and duration of any violation of this permit condition.

AQ-30 The project owner shall not operate the unit such that the daily heat input rate to S-7 Auxiliary Boiler exceeds 3,096 million BTU per day. (Cumulative Increase)

Verification: As part of the quarterly and annual compliance reports, the project owner shall include information on the date, time, and duration of any violation of this permit condition.

AQ-31 The project owner shall not operate the unit such that the combined cumulative heat input rate to S-7 Auxiliary Boiler exceeds 387,000 million BTU per consecutive twelve month period. (Cumulative Increase)

Verification: As part of the quarterly and annual compliance reports, the project owner shall include information on the date, time, and duration of any violation of this permit condition.

AQ-32 The project owner shall ensure that S-7 Auxiliary Boiler exhaust gas is abated by A-7 Oxidation Catalyst and A-8 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at S-7 and the A-8 SCR catalyst bed has reached minimum operating temperature. (BACT)

Verification: As part of the quarterly and annual compliance reports, the project owner shall include information on any major problem in the operation of the Oxidation Catalyst and the SCR systems for the boiler. The information shall include, at a minimum, the date, time, duration, and description of the problem, and the steps taken to resolve the problem.
shall not exceed 0.0114 lb/MM BTU (HHV) of natural gas

AQ-33 The project owner shall ensure that S-7 Auxiliary Boiler complies with requirements (a) through (h) at all times, except during an auxiliary boiler start-up or shutdown. (BACT, PSD)

(a) Nitrogen oxide mass emissions (calculated as NO_2) at P-4 (the exhaust point for S-7 Auxiliary Boiler, after abatement by A-7 Oxidation Catalyst and A-8 SCR System)
fired or 1.5 pounds per hour, averaged over any rolling 3-hour period. (PSD for NO_x)

(b) The nitrogen oxide emission concentration at P-4 shall not exceed 9.0 ppmv, on a dry basis, corrected to 3% O_2, averaged over any rolling 3-hour period. (BACT for NO_x)

(c) Carbon monoxide mass emissions at P-4 (the exhaust point for S-7 Auxiliary Boiler, after abatement by A-7 Oxidation Catalyst) shall not exceed 0.0386 lb/MM BTU (HHV) of natural gas fired or 5.0 pounds per hour, averaged over any rolling 3-hour period. (PSD for CO)

(d) The carbon monoxide emission concentration at P-4 shall not exceed 50 ppmv, on a dry basis, corrected to 3% O_2, averaged over any rolling 3-hour period. (BACT for CO)

(e) The precursor organic compound (POC) mass emission rates at P-4 shall not exceed 0.6 pounds per hour. (BACT for POC)

(f) The ammonia (NH_3) emission concentrations at P-4 shall not exceed 10 ppmv, on a dry basis, corrected to 3% O_2, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-8 SCR System. The correlation between the auxiliary boiler heat input rates, A-8 SCR System ammonia injection rate, and corresponding ammonia emission concentration at emission points P-4 shall be determined in accordance with permit condition 55. (TRMP for NH_3)

(g) Sulfur dioxide (SO_2) mass emissions at P-4 shall not exceed 0.09 pounds per hour or 0.0007 lb/MM BTU of natural gas fired. (BACT)

(h) Particulate matter (PM_{10}) mass emissions at P-4 shall not exceed 2.65 pounds per hour or 0.0205 lb/MM BTU of natural gas fired. (BACT)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

Conditions for All Sources

AQ-34 The project owner shall not allow total combined emissions from the Gas Turbines and HRSGs (S-1, S-2, S-3, S-4, S-5, and S-6), S-7 Auxiliary Boiler, S-9 Fire Pump Diesel Engine, and S-10 Emergency Generator, including emissions generated during Gas Turbine start-ups and shutdowns to exceed the following limits during any calendar day:

(a) 2,030.4 pounds of NO_x (as NO_2) per day (CEQA)

(b) 11,633.6 pounds of CO per day (PSD)

(c) 569.3 pounds of POC (as CH_4) per day (CEQA)

(d) 949.4 pounds of PM_{10} per day (PSD)

(e) 135.5 pounds of SO_2 per day (BACT)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-35 The project owner shall not allow cumulative combined emissions from the Gas Turbines and HRSGs (S-1, S-2, S-3, S-4, S-5, and S-6), S-7 Auxiliary Boiler, S-8 Cooling Tower, S-9 Fire Pump Diesel Engine, and S-10 Emergency Generator, including emissions generated during gas turbine start-ups and shutdowns to exceed the following limits during any consecutive twelve-month period:

(a) 263 tons of NO_x (as NO_2) per year (Offsets)

(b) 793.6 tons of CO per year (Cumulative Increase, PSD)

(c) 73.7 tons of POC (as CH_4) per year (Offsets)

(d) 148 tons of PM_{10} per year (Offsets)

(e) 21.33 tons of SO_2 per year (Cumulative Increase)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-36 The project owner shall not allow the combined heat input rate to the Gas Turbines and HRSGs (S-1, S-2, S-3, S-4, S-5, and S-6) and Auxiliary Boiler (S-7) to exceed 190,450 million BTU per calendar day. (PSD, CEC Offsets)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-37 The project owner shall not allow the cumulative heat input rate to the Gas Turbines and HRSGs (S-1, S-2, S-3, S-4, S-5, and S-6) and Auxiliary Boiler (S-7) combined to exceed 61,487,064 million BTU per year. (Offsets)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-38 The project owner shall not allow the maximum projected annual toxic air contaminant emissions (per condition 41) from the Gas Turbines and HRSGs (S-1, S-2, S-3, S-4, S-5, & S-6) combined to exceed the following limits:

formaldehyde	9,874.2 pounds per year
benzene	199.3 pounds of per year
Specified polycyclic aromatic hydrocarbons (PAHs)	9.9 pounds of per year

unless the following requirement is satisfied:

The project owner shall perform a health risk assessment to determine the total facility risk using the emission rates determined by source testing and the most current Bay Area Air Quality Management District approved procedures and unit risk factors in effect at the time of the analysis. This risk analysis shall be submitted to the District and the CEC CPM within 60 days of the source test date. The project owner may request that the District and the CEC CPM revise the carcinogenic compound emission limits specified above. If the project owner demonstrates to the satisfaction of the APCO that these revised emission limits will not result in a significant cancer risk, the District and the CEC CPM may, at their discretion, adjust the carcinogenic compound emission limits listed above. (TRMP)

Verification: Compliance with condition 41 shall be deemed as compliance with this condition. In addition, approval by the District and the CPM of the reports prepared for condition 41 will constitute a verification of compliance with this condition.

AQ-39 The project owner shall demonstrate compliance with conditions 18 through 21, 25(a) through 25(d), 26, 27, 29, 30, 31, 33(a) through 33(d), 34(a), 34(b), 35(a), and 35(b) by using properly operated and maintained continuous monitors (during all hours of operation including equipment Start-up and Shutdown periods) for all of the following parameters:

(a) Firing Hours and Fuel Flow Rates for each of the following sources: S-1 & S-2 combined, S-3 & S-4 combined, S-5 & S-6 combined, and S-7.

(b) Oxygen (O_2) Concentration, Nitrogen Oxides (NO_x) Concentration, and Carbon Monoxide (CO) Concentration at each of the following exhaust points: P-1, P-2, P-3, and P-4.

(c) Ammonia injection rate at A-2, A-4, A-6, and A-8 SCR Systems

The project owner shall record all of the above parameters every 15 minutes (excluding normal calibration periods) and shall summarize all of the above parameters for each clock hour. For each calendar day, the project owner shall calculate and record the total firing hours, the average hourly fuel flow rates, and pollutant emission concentrations.

The project owner shall use the parameters measured above and District-approved calculation methods to calculate the following parameters:

(d) Heat Input Rate for each of the following sources: S-1 & S-2 combined, S-3 & S-4 combined, S-5 & S-6 combined, and S-7.

(e) Corrected NO_x concentration, NO_x mass emission rate (as NO_2), corrected CO concentration, and CO mass emission rate at each of the following exhaust points: P-1, P-2, P-3, and P-4.

For each source, source grouping, or exhaust point, the project owner shall record the parameters specified in conditions 39(e) and 39(f) at least once every 15 minutes (excluding normal calibration periods). As specified below, the project owner shall calculate and record the following data:

a) total Heat Input Rate for every clock hour and the average hourly Heat Input Rate for every rolling 3-hour period.

b) on an hourly basis, the cumulative total Heat Input Rate for each calendar day for the following: each Gas Turbine and associated HRSG combined, the auxiliary boiler and all seven sources (S-1, S-2, S-3, S-4, S-5, S-6, & S-7) combined. hour period.

c) the average NO_x mass emission rate (as NO_2), CO mass emission rate, and corrected NO_x and CO emission concentrations for every clock hour and for every rolling 3-

d) on an hourly basis, the cumulative total NO_x mass emissions (as NO_2) and the cumulative total CO mass emissions, for each calendar day for the following: each Gas Turbine and associated HRSG combined, the auxiliary boiler, and all seven sources (S-1, S-2, S-3, S-4, S-5, S-6, & S-7) combined.

e) For each calendar day, the average hourly Heat Input Rates, Corrected NO_x emission concentration, NO_x mass emission rate (as NO_2), corrected CO emission concentration, and CO mass emission rate for each Gas Turbine and associated HRSG combined and the auxiliary boiler.

f) on a daily basis, the cumulative total NO_x mass emissions (as NO_2) and cumulative total CO mass emissions, for the previous consecutive twelve month period for all seven sources (S-1, S-2, S-3, S-4, S-5, S-6, & S-7) combined.

(1-520.1, 9-9-501, BACT, Offsets, NSPS, PSD, Cumulative Increase)

Verification: At least 30 days before first fire, the project owner shall submit to the CPM a plan on how the measurements and recordings required by this condition will be performed.

AQ-40 To demonstrate compliance with conditions 25(f), 25(g), 25(h), 26, 33(e), 33(g), 33(h), 34(c) through 34(e), and 35(c) through 35(e), the project owner shall calculate and record on a daily basis, the Precursor Organic Compound (POC) mass emissions, Fine Particulate Matter (PM_{10}) mass emissions (including condensable particulate matter), and Sulfur Dioxide (SO_2) mass emissions from each power train. The project owner shall use the actual Heat Input Rates calculated pursuant to condition 39, actual Gas Turbine Start-up Times, actual Gas Turbine Shutdown Times, and CEC and District-approved emission factors to calculate these emissions. The calculated emissions shall be presented as follows:

(a) For each calendar day, POC, PM_{10}, and SO_2 emissions shall be summarized for: each power train (Gas Turbine and its respective HRSG combined) and all seven sources (S-1, S-2, S-3, S-4, S-5, S-6, & S-7) combined.

(b) on a daily basis, the cumulative total POC, PM_{10}, and SO_2 mass emissions, for each year for all seven sources (S-1, S-2, S-3, S-4, S-5, S-6, & S-7) combined.

(Offsets, PSD, Cumulative Increase)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-41 To demonstrate compliance with Condition 38, the project owner shall calculate and record on an annual basis the maximum projected annual emissions of: Formaldehyde, Benzene, and Specified PAH's. Maximum projected annual emissions shall be calculated using the maximum Heat Input Rate of 61,100,064 MM BTU/year and the highest emission factor (pounds of pollutant per MM BTU of heat input) determined by any source test of the S-1, S-3, and S-5 Gas Turbines and/or S-2, S-4, and S-6 Heat Recovery Steam Generators. If the highest emission factor for a given pollutant occurs during minimum-load turbine operation, a reduced annual heat input rate may be utilized to calculate the maximum projected annual emissions to reflect the reduced heat input rates during gas turbine start-up and minimum-load operation. The reduced annual heat input rate shall be subject to District review and approval. (TRMP)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-42 Within 60 days of start-up of the EAEC, the project owner shall conduct a District-approved source test on exhaust point P-1, P-2, or P-3 to determine the corrected ammonia (NH_3) emission concentration to determine compliance with condition 25(e). The source test shall determine the correlation between the heat input rates of the gas turbine and associated HRSG, A-2, A-4, or A-6 SCR System ammonia injection rate, and the corresponding NH_3 emission concentration at emission point P-1, P-2, or P-3. The source test shall be conducted over the expected operating range of the turbine and HRSG (including, but not limited to, minimum and full load, and steam injection power augmentation mode) to establish the range of ammonia injection rates necessary to achieve NO_x emission reductions while maintaining ammonia slip levels. Source testing shall be repeated on an annual basis thereafter. Ongoing compliance with condition 25(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. Source test results shall be submitted to the District and the CEC CPM within 60 days of conducting the tests. (TRMP)

Verification: Approval of the source test protocols, as required in condition 16, and the source test reports shall be deemed as verification for this condition. The project owner shall notify the District and the CPM within seven (7) working days before the execution of the source tests required in this condition. Source test results shall be submitted to the District and to the CPM within 60 days of the date of the tests.

AQ-43 Within 90 days of start-up of the EAEC and on an annual basis thereafter, the project owner shall conduct a District-approved source test on exhaust points P-1, P-2, and P-3 while each Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum load (including steam injection power augmentation mode) to determine compliance with Conditions 25(a), (b), (c), (d), (f), (g), and (h), while each Gas Turbine and associated Heat Recovery Steam Generator are operating at minimum load to determine compliance with Conditions 25(c) and (d), and to verify the accuracy of the continuous emission monitors required in condition 39. The project owner shall test for (as a minimum): water content, stack gas flow rate, oxygen concentration, precursor organic compound concentration and mass emissions, nitrogen oxide concentration and mass emissions (as NO_2), carbon monoxide concentration and mass emissions, sulfur dioxide concentration and mass emissions, methane, ethane, and particulate matter (PM_{10}) emissions including condensable particulate matter. Source test results shall be submitted to the District and the CPM within 60 days of conducting the tests. (BACT, offsets)

Verification: Approval of the source test protocols, as required in condition 16, and the source test reports shall be deemed as verification for this condition. The project owner shall notify the District and the CPM within seven (7) working days before the execution of the source tests required in this condition. Source test results shall be submitted to the District and to the CPM within 60 days of the date of the tests.

AQ-44 The project owner shall obtain approval for all source test procedures from the District's Source Test Section and the CPM prior to conducting any tests. The project owner shall comply with all applicable testing requirements for continuous emission monitors as specified in Volume V of the District's Manual of Procedures. The project owner shall notify the District's Source Test Section and the CEC CPM in writing of the source test protocols and projected test dates at least 7 days prior to the testing date(s). As indicated above, the project owner shall measure the contribution of condensable PM (back half) to the total PM_{10} emissions. However, the project owner may propose alternative measuring techniques to measure condensable PM such as the use of a dilution tunnel or other appropriate method used to capture semi-volatile organic compounds. Source test results shall be submitted to the District and the CEC CPM within 60 days of conducting the tests. (BACT)

Verification: Submitting and getting approval of the source test procedures is the verification of this condition. The project owner shall notify the District and the CPM within seven (7) working days before the execution of the source tests required in this condition. Source test results shall be submitted to the District and to the CPM within 60 days of the date of the tests.

AQ-45 Within 90 days of start-up (commercial operation) of the EAEC and on a biennial basis (once every two years) thereafter, the project owner shall conduct a District-approved source test on exhaust point P-1, P-2, or P-3 while the Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum allowable operating rates to demonstrate compliance with Condition 36. The gas turbine shall also be tested at minimum load. If three consecutive biennial source tests demonstrate that the annual emission rates calculated pursuant to condition 39 for any of the compounds listed below are less than the BAAQMD Toxic Risk Management Policy trigger levels shown, then the project owner may discontinue future testing for that pollutant:

Benzene		6.7 pounds/year
Formaldehyde	$\leq$	33 pounds/year
Specified PAHs (TRMP)		0.044 pounds/year

Verification: The project owner shall notify the District and the CPM within seven (7) working days before the execution of the source tests required in this condition. Source test results shall be submitted to the District and to the CPM within 60 days of the date of the tests.

AQ-46 The project owner shall not allow the total combined sulfuric acid mist (SAM) emissions from S-1 through S-7 to exceed 7 tons totaled over any consecutive twelve month period. The SAM emission rate shall be calculated using the total heat input for the sources and the highest results of any source testing conducted pursuant to condition 47. If this SAM mass emission limit is exceeded, the project owner must utilize air dispersion modeling to determine the impact (in g/m^3) of the sulfuric acid mist emissions pursuant to Regulation 2-2-306. (PSD)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-47 Within 90 days of start-up (commercial operation) of the EAEC and on a semi-annual basis (twice per year) thereafter, the project owner shall conduct a District-approved source test on exhaust points P-1 through P-4 while each gas turbine, HRSG duct burner, and auxiliary boiler is operating at maximum heat input rates to demonstrate compliance with the SAM emission rates specified in condition 46. The project owner shall test for (as a minimum) SO_2, SO_3, and H_2SO_4. After acquiring one year of source test data on these sources, the project owner may petition the District to reduce the test frequency to an annual basis if test result variability is sufficiently low as determined by the District. Source test results shall be submitted to the District and the CEC CPM within 60 days of conducting the tests. (PSD)

Verification: The project owner shall notify the District and the CPM within seven (7) working days before the execution of the source tests required in this condition. Source test results shall be submitted to the District and to the CPM within 60 days of the date of the tests.

AQ-48 The project owner of the EAEC shall submit all reports (including, but not limited to monthly CEM reports, monitor breakdown reports, emission excess reports, equipment breakdown reports, etc.) as required by District Rules or Regulations and in accordance with all procedures and time limits specified in the Rule, Regulation, Manual of Procedures, or Enforcement Division Policies & Procedures Manual. (Regulation 2-6-502)

Verification: The project owner shall submit to the District and CPM the reports as required by procedures and time limits specified in the Rule, Regulation, Manual of Procedures, or Enforcement Division Policies & Procedures Manual.

AQ-49 The project owner of the EAEC shall maintain all records and reports on site for a minimum of 5 years. These records shall include but are not limited to: continuous monitoring records (firing hours, fuel flows, emission rates, monitor excesses, breakdowns, etc.), source test and analytical records, natural gas sulfur content analysis results, emission calculation records, records of plant upsets and related incidents. The project owner shall make all records and reports available to District and the CEC CPM staff upon request. (Regulation 2-6-501)

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, EPA or CEC staff.

AQ-50 The project owner of the EAEC shall notify the District and the CEC CPM of any violations of these permit conditions. Notification shall be submitted in a timely manner, in accordance with all applicable District Rules, Regulations, and the Manual of Procedures. Notwithstanding the notification and reporting requirements given in any District Rule, Regulation, or the Manual of Procedures, the project owner shall submit written notification (facsimile is acceptable) to the Enforcement Division within 96 hours of the violation of any permit condition. (Regulation 2-1-403)

Verification: Submittal of these notifications as required by this condition is the verification of these permit conditions. In addition, as part of the quarterly and annual compliance reports of Condition 25, the project owner shall include information on the dates when these violations occurred and when the project owner notified the District and the CPM.

AQ-51 The project owner shall ensure that the stack height of emission points P-1, P-2, and P-3 is each at least 175 feet above grade level at the stack base. (PSD, TRMP)

Verification: 120 days prior to the start of any site clearing or ground disturbance activities, the project owner shall provide the District and CPM an "approved for construction" drawing showing the appropriate stack height and location of sampling ports and platforms. The project owner shall make the site available to the District, EPA and CEC staff for inspection.

AQ-52 The project owner shall ensure that the stack height of emission point P-4 is at least 120 feet above grade level at the stack base. (PSD, TRMP)

Verification: 120 days prior to the start of any site clearing or ground disturbance activities, the project owner shall provide the District and CPM an "approved for construction" drawing showing the appropriate stack height and location of sampling ports and platforms. The project owner shall make the site available to the District, EPA and CEC staff for inspection.

AQ-53 The project owner of EAEC shall provide adequate stack sampling ports and platforms to enable the performance of source testing. The location and configuration of the stack sampling ports shall comply with the District Manual of Procedures, Volume IV, Source Test Policy and Procedures, and shall be subject to BAAQMD review and approval. (Regulation 1-501)

Verification: 120 days prior to the start of any site clearing or ground disturbance activities, the project owner shall provide the District and CPM an "approved for construction" drawing showing the appropriate stack height and location of sampling ports and platforms. The project owner shall make the site available to the District, EPA and CEC staff for inspection.

AQ 54 Within 180 days of the issuance of the Authority to Construct for the EAEC, the project owner shall contact the BAAQMD Technical Services Division regarding requirements for the continuous emission monitors, sampling ports, platforms, and source tests required by conditions 39, 42, 43, 45, and 60. All source testing and monitoring shall be conducted in accordance with the BAAQMD Manual of Procedures. (Regulation 1-501)

Verification: The project owner shall notify the CPM within 7 days of receiving the District's approval for the source testing and monitoring plan.

AQ-55 Prior to the issuance of the BAAQMD Authority to Construct for the East Altamont Energy Center, the Project owner shall demonstrate that valid emission reduction credits in the amount of 302.45 tons/year of Nitrogen Oxides, 84.755 tons/year of Precursor Organic Compounds, and 148 tons/year of PM_{10} or equivalent (as defined by District Regulations 2-2-302.1 and 2-2-302.2) are under their control through enforceable contracts, option to purchase agreements, or equivalent binding legal documents. (Offsets)

Verification: At least 30 days 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-56 Prior to the start of construction of the East Altamont Energy Center, the project owner shall provide to the District valid emission reduction credit banking certificates in the amount of 302.45 tons/year of Nitrogen Oxides, 84.755 tons/year of Precursor Organic Compounds, and 148 tons/year of PM_{10} or equivalent as defined by District Regulations 2-2-302.1 and 2-2-302.2. (Offsets, CEC)

Verification: At least 30 days prior to start of construction, the project owner shall provide valid emission reduction credit banking certificates to the District and the CPM for approval.

AQ-57 Pursuant to BAAQMD Regulation 2, Rule 6, section 404.1, the project owner of the EAEC shall submit an application to the BAAQMD for a major facility review permit within 12 months of completing construction as demonstrated by the first firing of any gas turbine, HRSG duct burner, or auxiliary boiler. (Regulation 2-6-404.1)

Verification: The project owner shall submit to the CPM copies of the Federal (Title IV) Acid Rain and (Title V) Operating Permit within 30 days after they are issued by the District.

AQ-58 Pursuant to 40 CFR Part 72.30(b)(2)(ii) of the Federal Acid Rain Program, the project owner of the East Altamont Energy Center shall submit an application for a Title IV operating permit to the BAAQMD at least 24 months before operation of any of the gas turbines (S-1, S-3, or S-5) or HRSGs (S-2, S-4, or S-6). (Regulation 2, Rule 7)

Verification: The project owner shall submit to the CPM copies of the Federal (Title IV) Acid Rain and (Title V) Operating Permit within 30 days after they are issued by the District.
The samples shall be analyzed for sulfur content using District-

AQ-59 The East Altamont Energy Center shall comply with the continuous emission monitoring requirements of 40 CFR Part 75. (Regulation 2, Rule 7)

Verification: At least 45 days prior to any site clearing or ground disturbance activities, the project project owner shall seek approval from the District for an emission monitoring plan.

AQ-60 The project owner shall take daily samples of the natural gas combusted at the EAEC.
approved laboratory methods. The sulfur content test results shall be retained on site for a minimum of five years from the test date and shall be utilized to satisfy the requirements of 40 CFR Part 60, subpart GG. (cumulative increase)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

Permit Conditions for S-8 Cooling Tower

AQ-61 The project owner shall properly install and maintain the cooling towers to minimize drift losses. The project owner shall equip the cooling towers with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0005%. The maximum total dissolved solids (TDS) measured at the base of the cooling towers or at the point of return to the wastewater facility shall not be higher than 3,400 ppmw (mg/l). The project owner shall sample and test the cooling tower water at least once per day to verify compliance with this TDS limit. (PSD)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-62 The project owner shall perform a visual inspection of the cooling tower drift eliminators at least once per calendar year, and repair or replace any drift eliminator components which are broken or missing. Prior to the initial operation of the East Altamont Energy Center, the project owner shall have the cooling tower vendor’s field representative inspect the cooling tower drift eliminators and certify that the installation was performed in a satisfactory manner. Within 60 days of the initial operation of the cooling tower, the project owner shall perform an initial performance source test to determine the PM_{10} emission rate from the cooling tower to verify compliance with the vendor-guaranteed drift rate specified in condition 61. The CPM may, in years 5 and 15 of cooling tower operation, require the project owner to perform source tests to verify continued compliance with the vendor-guaranteed drift rate specified in condition 61. (PSD)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-63 S-1, S-3, and S-5 Gas Turbines shall each be equipped with air inlet filter(s) and lube oil vent coalescer(s). (BACT for PM_{10})

Verification: One hundred and twenty (120) days prior to start any site clearing or ground disturbance activities, the project owner shall provide the District and CPM an "approved for construction" drawing showing the appropriate air inlet filter and lube oil vent coalescers.

Permit Conditions for S-9 Fire Pump Diesel Engine

AQ-64 S-9 Fire Pump Diesel Engine is subject to the requirements of Regulation 9, Rule 1 ("Sulfur Dioxide"), and the requirements of Regulation 6 ("Particulate and Visible Emissions"). The engine may be subject to other District regulations, including Regulation 9, Rule 8 ("NOx and CO from Stationary Internal Combustion Engines") in the future.

(Regulation 9, Rule 1, Regulation 6)

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, EPA or CEC staff.

AQ-65 The project owner shall ensure that S-9 burns no more than 1,420 gallons of diesel fuel totaled over any consecutive 12 month period for the purpose of reliability-related activities as defined by Regulation 9-8-232. (Offsets, BACT)

Verification: The project owner shall submit to the District and CPM the diesel fuel used in the quarterly and annual compliance reports as required by Condition 25.

AQ-66 The project owner may cause S-9 to burn an unlimited amount of diesel fuel for the purpose of providing power for the emergency pumping of water. (Regulation 9-8-330.1)

Verification: The project owner shall submit to the District and CPM the diesel fuel use in the quarterly and annual compliance reports as required by Condition 25.

AQ-67 The project owner shall equip S-9 with a non-resettable totalizing counter which records fuel use. (cumulative increase)

Verification: 120 days prior to the installation of the fire pump diesel engine, the project owner shall submit to the District and CPM the manufacturer specifications for the fuel meter.

AQ-68 The project owner shall ensure that the sulfur content of all diesel fuel combusted at S-9 does not exceed 0.0015% by weight. (TRMP, TBACT)

Verification: The project owner shall submit to the District and CPM sulfur content of the diesel fuel in the quarterly and annual compliance reports as required by Condition 25.

AQ-69 The project owner shall maintain the following monthly records in a District-approved log for at least 2 years and make such records and logs available to the District upon request:

a) total fuel use for S-9 for the purpose of reliability testing

b) total fuel use for S-9 for the purpose of emergency pumping of water

c) fuel sulfur content

(cumulative increase)

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, EPA or CEC staff.

Permit Conditions for S-10 Emergency Generator

AQ-70 S-10 Emergency Generator is subject to the requirements of Regulation 9, Rule 8 ("NOx and CO from Stationary Internal Combustion Engines") and the requirements of Regulation 6 ("Particulate and Visible Emissions"). (Regulation 9, Rule 8, Regulation 6)

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, EPA or CEC staff.

AQ-71 The project owner shall ensure that S-10 burns no more than 1,150 MM BTU (HHV) of natural gas totaled over any consecutive 12-month period nor 11.5 MM BTU (HHV) of natural gas per day for the purpose of reliability-related activities as defined by Regulation 9-8-232. (Offsets, BACT)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-72 The project owner may cause S-10 to burn an unlimited amount of natural gas for the purpose of emergency use as defined by Regulation 9-8-221. (Regulation 9-8-330.1)

Verification: he project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

AQ-73 The project owner shall equip S-10 with a non-resettable totalizing counter which records fuel use. (cumulative increase)

Verification: 120 days prior to the installation of the emergency generator, the project owner shall submit to the District and CPM the manufacturer specifications for the fuel meter.

AQ-74 The project owner shall maintain the following monthly records in a District-approved log for at least 2 years and make such records available to the District upon request:

a) total fuel consumption for S-10 for the purpose of reliability testing

b) total fuel consumption for S-10 for the purpose of emergency use

(cumulative increase)

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, EPA or CEC staff.

AQ-75 The project owner shall not operate both S-9 Fire Pump Diesel Engine and S-10 Emergency Generator on the same calendar day for the purposes of reliability-related activities. (PSD)

Verification: The project owner shall submit to the District and CPM the quarterly and annual compliance reports as required by Condition 25.

REFERENCES

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BIOLOGICAL RESOURCES

Testimony of 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, as well as guidelines established by the California Environmental Quality Act (CEQA). 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, or 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). Western is the lead federal agency for purposes of NEPA and the Endangered Species Act. Western must address impacts to floodplains and wetlands under the Department of Energy (DOE) Floodplain/Wetland regulations (Title 10, Code of Federal Regulations, section 1022) and Executive Orders 11988 and 1990.

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 consultation with the U.S. Fish and Wildlife Service (USFWS) if “take” may result during lawful project activities. Western was the lead agency in requesting the consultation. 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, prohibit 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.

Clean Water Act

Title 33 United States Code, section 404 et seq., prohibits the discharge of dredged or fill material into the waters of the United States without a permit. The administering agency is the Army Corps of Engineers.

Department of Energy-Floodplain and Wetland Regulations

This regulation at Title 10, Code of Federal Regulations (CFR), section 1022 establishes policy and procedures for discharging the Department of Energy's (DOE's) responsibilities with respect to compliance with Executive Order (E.O.) 11988 and E.O. 11990, including: (1) DOE policy regarding the consideration of floodplain/wetlands factors in DOE planning and decision-making; and (2) DOE procedures for identifying proposed actions located in floodplain/wetlands, providing opportunity for early public review of such proposed actions, preparing floodplain and wetland assessments, and issuing statements of findings for actions in a floodplain.

STATE

California Endangered Species Act of 1984

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

California Code of Regulations

Title 14, California Code of Regulations, sections 670.2 and 670.5, list 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.”

Protection for Migratory Birds

Fish and Game Code section 3513 protects California’s migratory birds by making it unlawful to take or possess any migratory nongame bird as designated in the Migratory Bird Treaty Act or any part of such migratory nongame bird.

Protection for Fully Protected Species

Fish and Game Code, sections 3511, 4700, 5050, and 5515, designate certain species as fully protected and prohibits the take of such species or their habitat unless for scientific purposes (see also California Code of Regulations Title 14, Division 1, Subdivision 3, Chapter 3, section 670.7).

Protection of Nest or Eggs

Fish and Game Code section 3503 protects California’s birds by making it unlawful to take, possess, or needlessly destroy the nest or eggs of any bird.

Protection of Significant Natural Areas

Fish and Game Code section 1930 et seq. designate 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., designate state rare, threatened, and endangered plants.

Delta Protection Act of 1992

Sections 29700 –29712, Legislate protection for the Sacramento-San Joaquin Delta and its natural resources including wildlife, fish, and the habitats on which they depend. Section 29760 specifies the adoption of a comprehensive, long-term resource management plan, which includes requirements for the conservation, preservation, and restoration of Delta wildlife, fisheries, and habitats.

LOCAL

Alameda County East County Area Plan (1994)

Policy 113 requires landscaping that 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.

There are also two regional resource management plans that have been developed to protect open space, habitats and populations of special status species (San Joaquin County 2000; USFWS 1998). Both of these plans establish a concern for special status species and loss of habitat quantity and quality in the project vicinity. The two plans include:

The San Joaquin County Multispecies Habitat Conservation and Open Space Plan (SJMSCP) provides a strategy for balancing protection of essential wildlife habitat as well as open space, with the increasing demands of human society and economy driving land development. This plan applies to San Joaquin County only, and relies upon minimizing, avoiding, and mitigating impacts to species covered within the plan. One of the focal species in the plan is the San Joaquin kit fox.

The Recovery Plan for Upland Species of the San Joaquin Valley, California. The primary objective of this recovery plan is the recovery of 11 endangered and threatened species, along with protection and long-term conservation of candidate species and species of special concern. The species covered in the plan inhabit grasslands and scrublands of the San Joaquin Valley, adjacent foothills, and small valleys. The San Joaquin kit fox is a focal species in this plan as well.

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 east of the Altamont Hills. 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 will require approximately 43.5 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 may 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 exist south, west, 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. Wetland review will also be required through Western per DOE Floodplain/Wetland review requirements found at Title 10, Code of Federal Regulations, section 1022. (ACOE) (EAEC 2001u, pp.12-14).

Vernal pool communities support highly co-evolved plants and animals that are endemic to these seasonally flooded depressions. Vernal pools form on the surface above an impermeable soil layer such as a hardpan, claypan, or volcanic basalt (Ericksen and Belk 1999; Holland and Jain 1988;Thorne 1984; USFWS 1994; USFWS 1996). 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 vernal pool fairy shrimp is a federally threatened species that potentially inhabits vernal pools near the proposed EAEC. The low-growing and sparse plant cover common around the 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, the closest 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 Applicant proposes to avoid vernal pool habitats 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). The proposed project will avoid significant direct impacts to this protected habitat area. The Applicant must 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 also 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). Riparian habitat does not occur on the EAEC project site, but it is present in the vicinity. 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 dona*x) exists where Mountain House Creek crosses Byron Bethany Road from southwest to northeast. Impacts to riparian habitats will be avoided or minimized by the proposed project.

EAEC Project Site Vegetation

Site vegetation was fallow and tilled when biology staff visited the site in May and August 2001 and March 2002. However, within the past 5 years the site has been used to cultivate oat-hay, alfalfa, tomatoes, and lima beans (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.

The irrigation ditches along the eastern boundary contain no woody vegetation or emergent vegetation but they do contain burrows that may be inhabited by San Joaquin kit fox or burrowing owl. 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*). No natural drainages or ponds exist on the EAEC project site, but there are agricultural drainage ditches along the southern and eastern borders.

Wildlife in the Project Area

Agricultural and ruderal vegetation provides habitat for both common and rare wildlife populations. For example, some commonly observed 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 in the area. Bats often feed on insects as they fly over agricultural and natural areas, and all bat species are state species of special concern.

Locally common and abundant wildlife species are important components of the ecosystem. Due to habitat loss, many of these species must continually adapt 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 but many occur in habitat conditions (i.e. vernal pools, wetlands) that are not present on-site. Surveys for special-status plants confirmed that none of the species were growing on the 174-acre project site or within the 43.5-arce area proposed to contain the power plant (EAEC 2001a, Table 8.2-1A). Long-term human management for intensive agriculture in the region has eliminated many of the local environmental conditions required for survival by these special-status plant species.

The CDFG identified potential for the presence of sensitive species and natural communities not mentioned in the AFC (CDFG 2001a, page 2). These include: loggerhead shrike, golden eagle, vernal pool fairy shrimp, rose mallow, Mason's lilaeopsis, and valley sink scrub plant community. These species and communities were evaluated and will be protected if nests, individuals, or habitats are found in areas impacted by EAEC facilities or linears.

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

Common Name	Scientific Name	Status
Plants		
Ferris' milkvetch	*Astragalus tener var ferrisiae*	FSC/1B
Alkali milkvetch	*Astragalus tener var. tener*	FSC/1B
Heartscale	*Atriplex cordulata*	FSC/1B
Brittlescale	*Atriplex depressa*	--/1B
San Joaquin saltbrush	*Atriplex joaquiniana*	FSC/1B
Big tarplant	*Blepharizonia plumosa ssp. plumosa*	--/1B
Hispid bird's-beak	*Cordylanthus mollis ssp. hispidus*	--/1B
Palmate-bracted bird's- beak	*Cordylanthus palmatus*	FE/SE/1B
Recurved larkspur	*Delphinium recurvatum*	--/1B
Diamond-petaled Calif.poppy	*Eschscholzia rhombipetala*	--/1B
Rose mallow	*Hibiscus lasiocarpus*	--/2
Mason's lilaeopsis	*Lilaeopsis masonii*	--/1B
Showy madia	*Madia radiata*	--/1B
Rayless ragwort	*Senecio aphanactis*	--/2
Showy indian clover	*Trifolium amoenum*	FE/-
Caper- fruited tropidocarpum	*Tropidocarpum capparideum*	FSC/1A
Insects and Crustacea		
Vernal pool fairy shrimp	*Branchinecta lynchi*	FT/-
Longhorn fairy shrimp	*Branchianecta longiantenna*	FE/
Vernal pool fairy shrimp	*Branchianecta lynchi*	FT/
Valley elderberry longhorn beetle	*Desmocerus californicus dimorphus*	FT/
Mammals		
San Joaquin pocket mouse	*Perognathus inornatus inornatus*	FSC/--
San Joaquin kit fox	*Vulpes macrotis mutica*	FE/ST
Riparian woodrat	*Neotoma fuscipes riparia*	FE/SSC
Riparian brush rabbit	*Sylvilagus bachmani riparius*	FE/SE
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
Common Name	**Scientific Name**	**Status**

Fish		
Sacramento River winter-run chinook	*Oncorhynchus tshawytscha*	FE/SE
Central Valley spring-run chinook	*Oncorhynchus* tshawytscha	FT/ST
Central Valley steelhead	*Oncorhynchus mykiss*	FT/SSC
Delta smelt	*Hypomesus transpacificus*	FT/ST
Critical habitat for the delta smelt		
Sacramento splittail	*Pogonichthys macrolepidotus*	FT/SSC
Central Valley fall/late fall run chinook	*Oncorhynchus. tshawytscha*	FC/--
Birds		
Bald eagle	*Haliaeetus leucocephalus*	FT/SE/SFP
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*	FPT/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.

IMPACTS AND ANALYSIS

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).

If built, the EAEC would result in the permanent removal of approximately 43.5 acres of prime agricultural land that also provides wildlife habitat. The construction laydown area, natural gas, water supply pipelines, and transmission lines would also result in temporary habitat losses, which 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 on the project site during biological surveys of the project area. However, there is the potential for the special status species to occur within the project site because the EAEC property, and vicinity, provide foraging and dispersal habitats in an area that has become increasingly fragmented by human development (Gan 2001a; Gan 2001b; Larson 2001). The

USFWS directed the Applicant to assume local presence of the federally endangered San Joaquin kit fox and to mitigate for habitat loss. There are other special status wildlife species, such as raptors, shorebirds, and songbirds that would benefit from the habitat mitigation established for the San Joaquin kit fox.

Table 2 BIOLOGICAL RESOURCES
Acreage Impacts

	Permanent Impacts (acres)	Temporary Impacts (acres)*
Power plant footprint	43.5	0
Construction laydown areas	0	29.1
Transmission tower footprints	0.5	0
Transmission line	N/A	N/A
Fiber optic cable installation	0	50 ft. x 1000ft. Right-of-Way
Raw water pipeline (Route 3E)**	0	2.2
Water supply pump at Canal 45	0.2	0
Recycled water supply pipeline		4.6 miles x 75 feet within a highly disturbed Right-of-Way
Natural gas pipeline (new preferred route) including meter station	0.5	8.2
Total	44.7	39.5 (excluding Rights-of-Way)

Source: EAEC 2001a, Table 8.2-2, page 8.2-17; EAEC 2001v, page 3; EAEC 2002d, Table 1)
*If the Right of Way is no longer graded and disked (highly disturbed) at the time of installation of the recycled water pipeline, biological surveys and mitigation for temporary impacts may be required in consultation with the USFWS and CDFG.

Impacts to Special Status Plants

The entire 174-acre project site has been heavily disturbed and cultivated over many decades, and does not support populations (or individuals) of special status plant species. However, the project site lies close to natural areas where some special status 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 that 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 if project activities occur in these areas. The plant species in **Biological Resources Table 1** have not been recorded on-site, and it is unlikely that any populations potentially persisting in the area will be significantly impacted by the proposed project facilities. However, plant species such as big tarplant and showy Indian clover may grow along grassland portions of project linear features.

The proposed project linears follow existing roads and rights-of-way as much as possible. The Applicant conducted plant surveys on-site and along proposed linears, which confirmed that agricultural and ruderal plant species predominate in the area. Special status plant species were not detected by the Applicant during these surveys. Nevertheless, 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 impacts to the plants, or to relocate them in compliance with the California Native Plant Protection Act. Western determined that there would be no significant impacts to the federally listed plant species (Western 2002a).

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 2001a; Larson 2001). For example, the EAEC project site and vicinity provide habitats suitable for San Joaquin kit fox, California red-legged frog, California tiger salamander, Swainson's hawk, burrowing owl, and other candidate, fully protected, or species of concern. The potential impacts to wildlife species of concern are discussed in the section below.

Mitigation for impacts to federally listed 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. A CDFG streambed alteration permit shall be required for alteration of streambeds and a Determination of Consistency shall be required to address impacts to state-listed species, such as the San Joaquin kit fox.

In general, in recognition of significant impacts to all sensitive species discussed below, the Applicant 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.

The USFWS Section 7 Consultation through Western

As the lead Federal agency, Western prepared the Biological Assessment which considered the effects of the proposed action on the Federally protected species (refer to Western 2002a and listed in **Biological Resource Table 1**). Under regulations 50 CFR 402.14(b), Western determined that the proposed action will not affect any of the invertebrates, fish species, reptiles, the riparian woodrat or the riparian brush rabbit or designated Critical Habitat. Western also determined that the proposed action may affect, but is unlikely to adversely affect, the bald eagle and mountain plover. Staff concurs with the determination of no impact to riparian woodrat, riparian brush rabbit, and bald eagle. Western's determination was based on discountable or insignificant effects due to the lack of habitat and evidence of usage of the project area by these birds. Based on agreements between the USFWS and the Applicant, the proposed action may adversely affect the California red-legged frog and the San Joaquin kit fox. The California tiger salamander, a Candidate species, would probably be affected by any actions that would affect the red-legged frog.

Below staff provides analysis of impacts to other federal and state listed species and species of special concern.

Significant Impacts

For the following species, staff has determined that the proposed project will remove or degrade habitats that are essential to the survival of special status species, particularly local populations. Habitat mitigation shall be required to decrease the impacts to less than significant levels.

San Joaquin kit fox: 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; O'Farrell 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 (O'Farrell 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 (O'Farrell 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 2001a; Larson 2001; O'Farrell 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).

Protocol level surveys were not conducted because the USFWS considered the area occupied, and protocol level surveys would not be useful to USFWS in determining mitigation (EAEC 2001r). Reconnaissance surveys conducted by the Applicant in January, May, and August 2001 did not find active or occupied dens on-site (Western 2002a, page 2-7). However, there are abundant ground squirrel burrows on site, on the berms and ditches around the borders of the site, and along the linear routes (EAEC 2001a page 8.2-1). These burrows may be enlarged and used by kit fox (EAEC 2001r).

On a larger scale, 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 2001a; 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 (Morrell 1975; O'Farrell 1983; Wheslar 1992; Zeiner et al. 1990). The project area is on the northern side of an essential migration corridor for the kit fox. The proposed project site also lies near the California Aqueduct and Delta Mendota Canal, both of which have been used by the kit fox as well as its predators and competitors (e.g. coyote and red fox). It is important to maintain the connectivity, quality, and quantity of the remaining kit fox habitat in this area of Alameda County.

The proposed project lies in Alameda County and very near the San Joaquin County boundary to the east. Alameda County constitutes a critical pinch point for the northern population of the kit fox (CDFG 2002a; Hau 2001; USFWS 2002d). The Recovery Plan for Upland Species of the San Joaquin Valley, The San Joaquin County Multi-species and Open Space Conservation Plan, and the Draft Conservation Strategy for the San

Joaquin Kit Fox in the Tracy Triangle Area, Alameda & San Joaquin Counties, California have identified the area within which the proposed EAEC would be located, as vital to the recovery of this species (USFWS 2002d).

The San Joaquin kit fox Planning and Conservation Team (KFPACT) was formed in May 2001. This group is composed of research and regulatory scientists, local, state, and federal agency representatives (including Energy Commission staff), and private organizations. Continual evaluation of research and conservation priorities has identified the area surrounding the proposed EAEC as a part of an essential habitat area and a valuable migration corridor for kit fox (KFPACT 2002a). This corridor is vital to maintain population viability and interconnectedness among the northern satellite population, as well as, connection with the more southerly kit fox population (Hau 2001; USFWS 2002d). The KF PACT has identified habitat loss and fragmentation, especially in the Livermore area and Tracy Triangle area, as priority concerns that need to be addressed to protect the species (Hau 2001; KFPACT 2002a; USFWS 2002d). Other important factors include the degradation of habitats with exotic vegetation and landscape features that favor coyote and red fox (Hau 2001).

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 proposed EAEC will permanently remove approximately 45 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 surrounding 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).

The EAEC will result in significant impacts to the San Joaquin kit fox because the project area constitutes important, occupied habitat for the dispersal, cover, foraging, and denning activities of this species (Gan 2001a; KFPACT 2002a; Larson 2001; Zeiner et al. 1990). In addition, the project linears follow road berms, rights-of-way, and levees that may be suitable for kit fox dens. These adverse impacts to the San Joaquin kit fox will be mitigated through the Biological Opinion, resulting from the section 7 consultation process between the USFWS and Western. CDFG participated in the consultation process and will provide a Consistency Determination for the San Joaquin kit fox because it is also a state listed species.

Potentially Significant Impacts

Staff has determined that the following special status species could potentially be significantly impacted by the proposed project without avoidance of sensitive habitats and the implementation of mitigation measures. These species are known to inhabit the project vicinity; however, the proposed project will not significantly impact essential portions of their habitat or geographic range. No known nests or actively occupied territories were found for these species in the project area. However, the impacts to foraging or nesting habitat may be significant in a cumulative manner, due to the rapid urbanization occurring in the project region. In cases of habitat loss, staff seeks to minimize impacts to all special status species. Consequently, staff seeks to ensure that the species in this category would benefit from habitat compensation mitigation provided for impacts to San Joaquin kit fox.

<u>California red-legged frog:</u> 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 this area is not suitable perennial habitat for the frog. Natural drainages near the corner of Kelso and Bruns roads, however, contained water as did several agricultural ditches and ponds. These drainages may be used by the red-legged frog during dispersal. The proposed project has a low potential to significantly affect populations and habitats of the California red-legged frog. However, because the frog is a listed species, any potential impact may be deemed significant and the USFWS Biological Opinion will cover this species as well. Avoidance of wetland habitat combined with habitat mitigation will effectively reduce adverse impacts to an insignificant level.

<u>California tiger salamander</u>: 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 have 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 for 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: 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 in 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 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. The Applicant reported a lack of suitable nest trees on-site, along linears and adjacent areas, and did not see any Swainson's hawks during surveys on May 4, August 14, 2000, or January 18, 2001 (EAEC 2001a, page 8.2-7). There are also no known communal roosts (used especially during migration) for this species on-site or on adjacent lands. Despite a lack of confirmed nesting habitat within the project area, staff is concerned about cumulative impacts from loss of hunting habitat in the region. The disturbance of habitats used by this species should be avoided or minimized. Overall, the EAEC will result in loss of approximately 45 acres of hunting habitat for this species. This may be significant without mitigation because rapid urbanization is occurring in the project vicinity.

Western pond turtle: 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.

Burrowing owl: The burrowing owl is a state species of special concern, that 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 been declining 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). This owl species has adapted to the changing landscape by using agricultural crops and rangelands for hunting and it nests along ditches, pastures, and agricultural fields. The EAEC will contribute directly to a loss of foraging habitat for this species. There were no occupied burrows on the project site, however, ground squirrel burrows were abundant on-site along the drainages, ditches, and linears and are potential habitat. Surveys to avoid any nests and relocate owls will enable avoidance of harm to this species.

Golden eagle: 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, and domestic livestock such as lambs and calves), rabbits, rodents, reptiles, birds, and carrion (Zeiner et al. 1990). Golden eagles inhabit 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 in the project area (Smith and Murphy 1973; Zeiner et al. 1990). 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. The EAEC will result in the permanent loss of potential foraging habitat for this species.

White-tailed Kite: This fully protected species inhabits oak grassland, rolling hills, and agricultural areas of California. The white-tailed kite is most active around dawn and dusk and hunts for 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). White-tailed kites roost communally in trees or on the ground and hunt in areas close to the roost. 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 near the Western Substation (Bridges 2001). The Applicant reported that they did not find any nests or communal roosts of this species on-site or within 5 miles of the EAEC project site. Approximately 45 acres of hunting, and potential communal roosting habitat will be permanently and adversely impacted by the EAEC.

Short-eared owl: This 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 consists of 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 Applicant during biological surveys, the site is potential habitat for the short-eared owl. The proposed project will result in the loss of approximately 45 acres of hunting habitat for this species.

Northern harrier: 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. The harrier faces many of the same problems as the short-eared owl. Harriers nest on the ground and have suffered a reduction in range due to human alteration and destruction of 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). The loss of agricultural and fallow or natural habitats due to the EAEC may adversely affect this species.

Loggerhead shrike: 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 that feeds on rodents, reptiles, amphibians, and small birds (Zeiner et al. 1990). The EAEC will permanently remove 45 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.

<u>California horned-lark</u>: 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 fields on the EAEC project site and larks may nest in fallow vegetation around the EAEC project site. Thus, the EAEC will result in a permanent loss of foraging habitat for this sensitive species.

<u>Tricolored blackbird</u>: The tricolored blackbird 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.

<u>Mountain Plover</u>: This diurnal plover is proposed for federal listing as a threatened species and is a state species of special concern. The mountain plover 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 45 acres of potential foraging habitat for this species.

<u>Bats:</u> 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. However, the proposed project will result in a loss of foraging habitat, which in turn may result in significant cumulative impacts to

regional habitats. Any special status bat species in the area would benefit from the habitat mitigation proposed nearby.

No Impacts or Less than Significant Impacts

Staff has determined that the following species will not be impacted by the proposed project.

San Joaquin Pocket Mouse: 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. Consequently, impacts to this 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, well below the reported range for this species (EAEC 2001a, page 8.2-14). The EAEC project site itself does not provide suitable habitat. It is unlikely that the species would be present in the developed agricultural lands surrounding the EAEC project site. Therefore, project impacts to this species are not expected to be significant.

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 will require approximately 4,616 acre-feet per year (AFY) of water, and up to 7,000 AFY in peak years. (EAEC 2001a, page 8.14-4). This water would be delivered by the Byron Bethany Irrigation District (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). BBID maintains that serving the EAEC with this water will not result in additional water diversions from the California Aqueduct. 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 (Delta Protection Act 1992; NMFS 2001a). The Delta also supports fish of importance to sport fishermen (EAEC 2001a page 8.2-19; NMFS 2001a). In the PSA staff was 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) 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 (NMFS 2001a; NMFS 2002b). As part of Western's section 7 consultation with the NMFS, NMFS evaluated the following species for impacts: 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*). In their first response letter NMFS concluded: "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 2001a).

The NMFS submitted comments during formal section 7 consultation with Western on March 20, 2002 and June 5, 2002 (NMFS 2002a; NMFS 2002b). In these response letters, NMFS indicated that, according to their review of the most up-to-date project information, the proposed EAEC would not result in significant adverse impacts to Delta fish. The June 5, 2002 letter also provided an explanation of the NMFS concurrence with Western's determination, based upon new information confirming the project's water supply. At the same time, the NMFS stated that if the project description changes, reconsideration of their determination may be necessary. Based on the available data, staff concurs with the NMFS determination of no significant impacts to special status Delta fish species.

Impacts Related to Landscaping and Visual Screening

The Applicant has proposed landscaping around the facility to partially screen the project structure (refer to the **Visual Resources** section of this Staff Assessment). The landscape around the proposed EAEC was historically open grassland. The natural openness of the area has been modified by many types of exotic trees that have been planted around building structures. Such modification has altered the habitat characteristics of the local landscape, resulting in adverse impacts to species reliant upon open grasslands. One such species is the San Joaquin kit fox.

The USFWS and CDFG indicated that the Applicant's original landscape plan would result in unacceptable adverse biological impacts to listed, sensitive, and protected wildlife species (CDFG 2001a; Gan 2001a; Larson 2001). The area around the EAEC still provides important habitat, which connect increasingly fragmented habitat patches and provides potential dispersal, hunting, and nesting habitats for many special status species. 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 (see also, KFPACT 2002a).

In particular, the USFWS and CDFG expressed concerns that planting large trees and shrubs would provide nesting and perching sites for large raptors. Large raptors would prey upon San Joaquin kit fox, and other special status species, whose populations are threatened by habitat loss, habitat degradation, habitat fragmentation, and/or competition with non-native species (Hau 2001; KFPACT 2002a; Larson 2001). In addition, the planting of shrubs and trees within grasslands creates habitat conditions that favor the red fox and coyote while degrading its quality for use by kit fox. The plantings would likely provide refuge and hunting cover for terrestrial predators (i.e. coyote, and the non-native red fox) whose local abundance is particularly detrimental to San Joaquin kit fox populations in this critical habitat area (Gan 2001b; Larson 2001; USFWS 2002d). 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 the species. 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 (e.g. kit fox) is that the mortality rate becomes greater than reproductive success and survival, and the habitat becomes a sink, thus causing a species’ decline (Meffe and Carroll 1997; Pulliam, H.R. 1988).

Western has also expressed concern that the planting of numerous trees around the facility would attract birds such as doves, blackbirds, pigeons, and starlings (Bridges 2001a). The Western Tracy Substation has documented problems with birds colliding with their electrical equipment and causing outages (Bridges 2002a; Sornborger 2002a). Consequently, Western has expressed concern that the planting of additional trees would attract more birds and increase the frequency of bird collisions and electrocutions with the EAEC switchyard (which will be owned by Western).

There are also relevant policies in Alameda County. 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, that harms special status species (per comments of USFWS and CDFG).

The Applicant attempted to develop a landscaping plan that would visually screen the facility from key observation points without causing significant biological impacts (EAEC 2001y, page 2). Three workshops were held to discuss this issue (September 12, 2001, November 7, 2001, and January 22, 2002). In response to comments on the second design, a third plan was submitted by the Applicant on April 3, 2002. Although USFWS, CDFG and staff prefer that no trees and shrubs are planted around the project site, it was agreed that the landscaping plan submitted on April 3, 2002 would sufficiently minimize biological impacts. The trees are planted very close to the site fence and the design incorporates many native plant species as well as management practices designed to minimize biological impacts to San Joaquin kit fox (see mitigation section).

Construction Impacts

The proposed generating facility site would require a 43.5-acre power plant footprint, including the area to be used for landscaping (EAEC 2001 section 8.2 pages 17-18; EAEC 2002a). Construction of the generating facility and linears will result in permanent loss of approximately 45 acres of habitat as well as temporary disturbances to approximately 40 acres of habitat. The proposed construction laydown area will be compacted and overlain with a layer of gravel or other material. Upon completion of laydown, the site will be returned to agricultural use (EAEC 2001a, page 8.2-28) or restored as natural vegetation using plants approved by Energy Commission in consultation with the USFWS, Western, and CDFG. 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 animal species. Construction may also disturb sensitive plant 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 would be significant but may 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.

Operation Impacts

Operation of the proposed project will result 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 2001a, 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

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.

<u>Cooling Tower Drift:</u> 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 is 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 PM10 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 PM10 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). 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. The EAEC is surrounded by agricultural fields, which may provide attractive foraging habitat for birds such as egrets, herons, and birds of prey. However, these species should have ample visibility and clearance to avoid hitting the stacks. Staff concludes that the HRSG stacks are not expected to cause significant numbers of bird collisions. If a collision problem is detected on the facility by the Designated Biologist, corrective action and/or monitoring should be implemented.

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 subsequent submittal (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 to 40 dBA during the night, and L90 levels between 35 to 45 dBA during the day, mostly due to distant traffic (EAEC 2001a, page 8.5-6; EAEC 2001w, pages 40-42). The increases from the plant (as much as 13 dBA) would be significant and would need to be mitigated (EAEC 2001a, page 8.5-8). The predicted operational noise levels are below 60 dBA, which is the threshold level 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 60 dBA. 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 proposed 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 to 98 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 downward 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 all rodenticides, herbicides, and insecticides shall be consistent with USDA label requirements.

IMPACTS FROM LINEAR FACILITIES

Natural Gas Supply Pipeline

A new preferred gas pipeline route was presented by the Applicant on February 6, 2002 (EAEC 2002a, page 2, Figure 1). This new pipeline route would be 1.8 miles long. As sited, the pipeline originates from the EAEC site and follows the route 2A pathway for 0.9 miles. However, unlike alternative 2A, it would turn southwest at the Delta Mendota Aqueduct and run along the eastern side of the Aqueduct for approximately 0.9 miles to its terminus at the PG&E main pipeline.

The new 0.9 mile section running along the Aqueduct would transect sensitive habitats such as those open habitats used by San Joaquin kit fox and burrowing owl. In addition, there are three wetlands, that may be impacted. These three areas are packed-earth or concrete-lined canals operated by BBID (Canals 70, 120 and 155). They are seasonally dry and lack aquatic or riparian vegetation. Constructing in these areas when flow is not present in the canal and preventing adverse impacts to water quality will be sufficient to avoid significant adverse impacts to sensitive species. The southern segment of the pipeline may impact designated critical habitat for the California red-legged frog as well as the habitat of the western pond turtle (EAEC 2002a, page 8). The California tiger salamander has been found less than 0.5 miles from the pipeline route and may also disperse through this area or estivate in burrows along the pipeline route. The areas that may be impacted are water channels that are maintained by the BBID and are seasonally dry and devoid of riparian vegetation. Pre-construction surveys and implementation of construction during the dry season would eliminate significant impacts to these areas. The Biological Resources Mitigation Monitoring and Implementation Plan will address the monitoring of listed species prior to and during construction of the gas pipeline. Habitat mitigation will provide habitats to benefit the kit fox and burrowing owl, as well as wetlands, that provide habitat for salamanders, frogs, and turtles.

Alternative 2A (the Applicant's original preferred alternative) would require 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. Staff supports both this alternative and the new preferred alternative because both routes will be constructed to avoid and mitigate the adverse biological impacts to sensitive habitats, plants, and wildlife.

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.

Construction Impacts: Construction of the preferred natural gas supply pipeline would require horizontal directional drilling (HDD), trenching, or jack and bore construction methods (at the railroad crossing). Impacts due to construction of the pipeline will be temporary disturbance of ruderal vegetation along the north side of the road (EAEC 2001a, page 8.2-20). 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 Impacts: 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 Impacts: Maintenance of the gas pipeline will involve weed control above the pipeline route along Bruns Road and Kelso Road (EAEC 2001a, page 8.2-20). 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. No significant impacts resulting from pipeline maintenance are expected unless the pipeline maintenance requires ground disturbance. At such a time, the USFWS and CDFG should be consulted.

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

Raw Water Supply Pipeline

All proposed raw 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. The pipeline would run south along Bruns Road east of 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 (HDD) (EAEC 2001a, page 8.2-18). 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 (EAEC 2001a, page 8.2-18). If construction requires disturbance of drainages or streams, a CDFG Streambed Alteration Agreement may be needed.

Construction Impacts: The impacts to biological resources from the raw water supply pipeline are projected to be insignificant because wetland and sensitive species will be surveyed prior to construction and avoided. Construction of the water supply lines would require HDD and trenching in some locations, as well as temporary construction staging areas. 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 and CDFG 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. EAEC LLC has refined the construction of the water supply route by extending the horizontal directional drill so that the pipe will “daylight” on the EAEC LLC 174 acre parcel, which is on the east side of Mountain House Road (EAEC 2002a, page 3). This will eliminate the trenching of Mountain House road for this project feature. 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 unless the pipeline maintenance requires ground disturbance. At such a time, the USFWS and CDFG should be consulted.

Recycled Water Supply Pipeline

The Applicant has proposed to design the EAEC with the capacity to use recycled water from the Mountain House Community Service District Wastewater Treatment Plant (MHCSD WWTP). Please refer to the **Soil and Water Resources** section of this Staff Assessment for analysis of the recycled water supply. In the AFC, the Applicant originally provided two alternative routes (**4A** and **4B**), both of which are approximately 4.6 miles long. The routes differed in their origin from the project site and in their location along the north or the south side of Byron Bethany Road (EAEC 2001a; Figure 2.1-1).

The Applicant's original preferred route **4B** exits the northwest corner of the project site, heading north to Byron Bethany Road and then turned south. At this point the route had the potential to be sited on the north or south side of Byron Bethany Road. This route would have resulted in significantly greater impacts to sensitive biological resources than route **4A**, which started at the southwestern edge of the project site and traveled west along Kelso Road to the south side of the Byron Bethany Road. Both pipeline routes crossed creek beds and the Union Pacific Railroad and terminated at the future MHCSD WWTP pump station (EAEC 2001a, Figure 8.2-1, page 2-11 to 2-12, and section 7.1.2).

The Applicant has since refined the preferred route **4B** such that the pipeline would: 1) exit the project site at the northeast corner, rather than the northwest corner, and 2) be installed along the south side of Byron Bethany Road. This change was made in order to avoid biological resources on the north side of the road (EAEC 2002a, page 3 and Figure 2).

Staff concurs with the Applicant's preferred recycled water pipeline route. Special status species, such as the San Joaquin kit fox, California red-legged frog, western pond turtle, Swainson's hawk, and burrowing owl are unlikely to be impacted by construction of the pipeline along the refined route **4B**. A kit fox den was identified less than 2,000 feet from the area of the proposed water source and, as such, there is still the potential for impacts at that location. 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). Any temporary impacts to special status species and habitats (wetlands, ruderal, and agricultural) may be mitigated to less than significant levels with avoidance and minimization measures as well as compliance with conditions contained in any required CDFG and ACOE permits.

<u>Construction Impacts:</u> The refinements to the recycled water pipeline and the raw water pipeline will avoid sensitive habitats and reduce the amount of construction required for the line. Therefore, the new recycled water pipeline route presented in EAEC (2002a) will result in fewer biological impacts due to the highly disturbed nature of the installation route. The Applicant proposes to install the recycled water pipeline on the south side of Byron Bethany Rd. The south side of the road is presently graded and disked due to a separate and ongoing construction project (EAEC 2002a).

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.

Fiber Optic Cable

Western requested the installation of an 8-inch fiber optic cable conduit from the EAEC switchyard west across Mountain House Rd. along an existing dirt road and into the north side of theTracy Substation, a linear distance less than 1,000 ft. and a width of 50 ft. (EAEC 2002a, page 2, Figure 2). The fiber optic cable will provide a second communication path between the EAEC switchyard and the Tracy Substation. The installation of this cable via trenching will temporarily disturb ruderal vegetation. With appropriate construction avoidance and mitigation measures, adverse impacts will be insignificant. Operation of the cable will not result in biological impacts.

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 lines 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 potential 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. However, there has been a documented problem with bird electrocution and “nuisance” perching at the Tracy Substation, which lies directly across the street (Sornborger 2002a). Ultimately, the EAEC has the potential to create an increase in avian collisions with the new transmission lines. Staff recommends implementation of a short-term (one year) monitoring program to quantify avian collisions, and electrocutions.

Construction Impacts: Construction impacts of the transmission line will include the permanent removal of approximately 0.5 acres of agricultural vegetation on the south side of the Kelso Road near the Western Substation. The same area under the towers would be temporarily disturbed by equipment (flatbed and crane) during construction.

Maintenance Impacts: Maintenance impacts may include increased traffic and the storage of equipment during repairs. Impacts should be minimal when best management practices are implemented.

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 45 acres of wildlife habitat. There are two additional energy projects under review or approved 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 project (submitted 8/16/01 and approved July 17, 2002) 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 potentially 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 potentially significant cumulative adverse impacts to endangered populations of native fish species.

The EAEC will contribute to the cumulative loss and degradation of habitats essential to the persistence and recovery of special status wildlife species. Staff seeks to ensure that potential cumulative impacts from the EAEC are mitigated. Through agency-approved terrestrial mitigation, such as that proposed by the Applicant, the EAEC will mitigate impacts to less than significant levels and avoid contributing to potentially significant cumulative terrestrial impacts.

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 of the proposed facility (EAEC 2001a, section 8.2.3; EAEC 2001u, pages 1-21; EAEC 2002d).

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 is in the process of obtaining a section 7 permit from USFWS with Western acting as the lead agency. The section 7 permit will specify actions that 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). The Applicant also committed to avoid wetlands and implement wetland and waterway protection measures (EAEC 2001u, pages 12-15).

Habitat Mitigation

The Applicant has proposed to mitigate for significant adverse impacts to listed species by providing the money to purchase suitable mitigation habitat. Specifically, the Applicant has proposed habitat mitigation/compensation for the San Joaquin kit fox (EAEC 2002d). The California red-legged frog, California tiger salamander, and other special status species will also benefit from the protection and management of this habitat (EAEC 2001p, pages 1-2; EAEC 2002d).

The Applicant proposes to place a conservation easement on the Gomes Farms property, a 151-acre parcel that lies approximately one mile west of the EAEC project site (EAEC 2002d, Figures1). The Applicant obtained this property with CDFG, USFWS, and Energy Commission staff guidance. The habitat value of this parcel is high because the parcel:

- provides suitable short grassland habitat for San Joaquin kit fox and other special status species;
- creates and maintains habitat connectivity with adjacent wildlife preserves, mitigation parcels, and open space;
- contains rare habitat features and a diversity of habitat types(e.g. alkali marsh and wetlands, connectivity to uplands and riparian drainages); and
- provides adequate size to mitigate for impacts of the project.

The Applicant proposes to establish a conservation easement on the 151-acre parcel, to prepare a management plan, and to establish an endowment to manage the parcel in perpetuity. The size of the endowment will be based upon a Property Analysis Report (PAR), that will be conducted through the Center for Natural Lands Management (CNLM). The mitigation land will be managed by a qualified third party natural land management organization approved by Energy Commission staff, USFWS, CDFG, and Western.

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:

Obtain and comply with the conditions of a section 7 authorization for incidental take of this species;

1. Conduct pre-design surveys for all areas potentially affected by the project;
2. Set and enforce speed limits in the construction area at 20 miles per hour or less;
3. Provide any excavations or ditches with escape ramps and check for trapped wildlife before work commences each day;
4. Cap pipes over 4 inches in diameter or check before they are moved; and
5. Implement 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 is occupied;
2. Avoid all suitable breeding habitats; and
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. Conduct pre-construction field surveys shall be implemented to identify potentially suitable habitat; and
2. Implement 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; and

3. An incidental take agreement (CDFG Section 2080.1) will be obtained if construction cannot avoid active nests by ½ mile.

Burrowing Owl:

1. Conduct pre-construction surveys in the spring (before February 1) to determine if habitat is occupied by burrowing owls;
2. Implement mitigation measures that protect burrowing owls by passive relocation and/or restriction of any 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); and
3. Incorporate areas in landscape/mitigation corridor for forage and potential burrow habitat.

California Horned Lark:

1. Perform surveys at the appropriate time of year to identify locations of potential nests within 100 feet of project features; and
2. Avoid construction in the vicinity of horned lark nests (EAEC 2001a, page 8.2-13).

Tricolored Blackbird:

1. Conduct pre-construction surveys for this species within 100 feet of project features; and
2. Avoid wetlands as well as construction in the vicinity of blackbird 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; and
3. Lease the 134-acres of land surrounding the EAEC for use in wildlife-friendly agriculture (per USFWS and CDFG guidelines).

The Applicant also agreed to conduct additional surveys for tarplant (EAEC 2001p, data response 46).

Mitigation for Landscaping and Visual Screening

In an attempt to reduce the biological impacts due to the landscaping for visual screening, the Applicant submitted a revised landscape plan on April 3, 2002 (EAEC 2002c). The landscaping also lies within the 43.5 acre footprint. Therefore, additional habitat compensation was not proposed. The revised plan incorporates several measures designed to decrease biological impacts including: locating the vegetation closer to the project fence, increasing the use of native species, decreasing the use of large trees, and proposing to maintain shrubs and trees with a 3 foot clearance from the ground.

Mitigation Practices for Construction

The Applicant has proposed to implement 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; and

compliant with EAEC best management practices and procedures for protecting biological resources at all times;

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 (required in staff's proposed Condition of Certification **BIO-5)**;

Conform with the BRMIMP and general mitigation measures at all times (required in staff's proposed Condition of Certification **BIO-12**);

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;

Use of existing roads for the delivery of construction materials and equipment to the site and laydown area; and

Removal of the temporary construction laydown area and restoration to its existing condition as soon as feasible after construction was complete (EAEC 2001a, page 8.2-28).

The Applicant did not provide specific mitigation for decommissioning of the power plant facility but rather 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 steam blows 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; and
>
> 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.

In addition, the Applicant proposes the following (EAEC 2001a, page 8.2-28):

> HDD would be used to bore the pipelines under drainages, canals, and sensitive habitats;
>
> Vegetation would be removed when trenching methods are used to install pipelines. Most of the habitat disturbed would be annual grassland and weeds occurring along roadsides, but some agricultural fields could also be trenched; and
>
> After construction, the trench would be back-filled with the excavated soil and restored to pre-construction conditions, both with respect to contour and to 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 that, with agency-approved habitat mitigation, the impacts would be insignificant (EAEC 2001a, page 8.2-29).

STAFF’S PROPOSED 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, many of which were originally put forth by the Applicant:

Hiring of a Designated Biologist and Biological Monitors (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-7, BIO-8,** and **BIO-9)**;

Preparation of a BRMIMP (see Condition of Certification **BIO-5)**;

Implementation of construction and operation mitigation measures (see Conditions of Certification **BIO-11**and **BIO-12)**; and

Preparation of facility closure plans (for emergency and permanent closures) (see Condition of Certification **BIO-6**).

Staff supports the proposed habitat mitigation strategy for addressing permanent and temporary habitat losses, as well as, a minimization of adverse impacts caused by landscaping in this critical habitat region for the San Joaquin kit fox (see Conditions of Certification **BIO-13** and **BIO-14**).

Under Western’s review process, the proposed project must comply with the Department of Energy-Floodplain and Wetland Regulations. Specifically, Title 10, Code of Federal Regulations,section 1022 establishes policy and procedures for the Department of Energy's (DOE's) responsibilities with respect to compliance with Executive Orders 11988 and 11990, including: (1) DOE policy regarding the consideration of floodplain/wetlands factors in DOE planning and decision-making; and (2) DOE procedures for identifying proposed actions located in floodplain/wetlands, providing opportunity for early public review of such proposed actions, preparing floodplain and wetland assessments, and issuing statements of findings for actions in a floodplain. Western may thus require the Applicant to prepare a Wetland Assessment, per the requirements in Title 10, Code of Federal Regulations, section 1022 (see Condition of Certification **BIO-15**). Western will determine the need for this assessment. If required, this assessment including mitigation measures shall be prepared prior to initiation of construction of the pipelines and shall be included within the BRMIMP.

Habitat Mitigation (Condition of Certification BIO-13)

In accordance with USFWS and CDFG requirements, the significant permanent and temporary losses of habitats used by special status species must be mitigated (Gan 2001a; Larson 2001). Overall, staff supports the Applicant's proposed acquisition of the

Gomes property and provision of an endowment through a qualified and approved third party management entity (as provided in EAEC 2002d). The proposed mitigation was developed in consultation with USFWS, CDFG, and Energy Commission staff over many months. In staff's opinion, a local parcel with high biological value was obtained to provide habitat for kit fox, burrowing owl, amphibians, raptors, and other special status species. This parcel is also contiguous with other preserve lands or protected areas and habitat types.

The entire 151-acres shall apply for the habitat impacts of the project. If the Applicant incurs additional impacts in the future, they will need to purchase additional acres of habitat at an agency-approved location, using a 3:1 ratio for permanent impacts and a 1:1 ratio for temporary impacts.

In addition, if the Applicant implements additional landscaping, other than the plan approved by the USFWS, Western, CDFG, and Commission staff, they shall be required to provide additional habitat mitigation for the acres impacted by the landscaping; A 3:1 ratio will apply for permanent impacts and a 1:1 ratio will apply for temporary impacts.

The Applicant has also 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 various bird species (EAEC 2001v, Supplement B, page 3). Please refer to the **Land Use** Section of this Staff Assessment. However, the agricultural lands north and south of the power plant facility were not proposed as part of the biological resources habitat mitigation package. Because the Gomes Farms parcel fully mitigates for the project’s biological impacts, staff has not written a biological Condition of Certification regarding this agricultural easement. Although staff supports the Applicant’s proposal to maintain the areas north and south of the facility in agriculture, staff is concerned that the agricultural crops and practices implemented in this area may not always benefit wildlife. For example, staff does not support the installation of vineyards or orchards in this area due to their low value as habitat for San Joaquin kit fox and other grassland species.

Mitigation for Landscaping and Visual Screening (Condition of Certification BIO-14)

Biology staff prefers that there would be no landscaping around the facility due to biological impacts to the San Joaquin kit fox. However, the Applicant's April 3, 2002 conceptual landscaping plan is acceptable (refer to Condition of Certification **VIS-3**). This plan has been reviewed and approved by the USFWS, CDFG, and Western in consultation with Energy Commission staff. The April 3, 2002 plan minimizes the use of large trees and includes an acceptable selection of native plant species (EAEC 2002c). The Applicant's proposed management of the landscaping, including the maintenance of a 3 foot clearance from the bottom of the vegetation to the ground, is also acceptable. The Applicant should also consult with Western regarding the distance of landscaping from electrical equipment (Bridges 2002a). The final landscaping design should be approved by Energy Commission staff in consultation with the USFWS, CDFG, and Western. Any changes to the April 3, 2002 landscaping plan and management practices should be approved by the USFWS, CDFG, and Western in consultation with Energy Commission staff.

In addition, staff recommends that the Applicant install artificial refuge dens for the San Joaquin kit fox around the perimeter of the project (refer to Condition of Certification **BIO-14**). These dens will provide the kit fox with a place to escape from predators. The use of these dens by kit fox and other mammals should be monitored and the red fox population (also proposed by the Applicant) should be controlled. The details of this installation and monitoring will be developed in consultation with the USFWS, CDFG, and Western and included in the BRMIMP.

Avoidance and Minimization Measures to Protect Special Status Species (Condition of Certification BIO-12)

Staff recommends the implementation of pre-construction surveys for the following species:

Listed and sensitive plant species (i.e. big tarplant), which may grow along grassland portions of project linear features;

Listed and sensitive animal species such as those listed in the Applicant's proposed mitigation, and all raptor nests (including northern harrier and short-eared owl), and

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.

Staff also recommends the implementation of a one-year monitoring program to determine impacts from avian collisions with transmission lines and electrical equipment. The monitoring program will be developed in consultation with Western and CDFG and provided as part of the BRMIMP.

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-11, BIO-12** and **BIO-6** for facility closure).

Mitigation for Impacts from the Gas Supply Pipeline

Staff supports the selection of the preferred gas supply pipeline route because it will avoid 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. The Applicant shall comply with conditions set forth through USFWS, CDFG, and ACOE permits required for the project. Western may require the Applicant to prepare a Wetland Assessment, per the requirements in Title 10, Code of Federal Regulations, section 1022 (see Condition of Certification **BIO-15**).

Mitigation for Impacts from the Water Supply Pipeline

Staff supports selection of alternative 3E, the Applicant's preferred water supply pipeline route. Mitigation will include the Applicant's proposed mitigation measures and full compliance with USFWS, CDFG, and ACOE permit conditions. Western may require the Applicant to prepare a Wetland Assessment, per the requirements in Title 10, Code of Federal Regulations, section 1022 (see Condition of Certification **BIO-15**).

Mitigation for Impacts from the Recycled Water Pipeline

Staff concludes that the Applicant's preferred recycled water pipeline route is acceptable, upon implementation of pre-construction surveys, compliance with federal and state permits, habitat mitigation, and avoidance and minimization measures. The Applicant shall comply with conditions set forth through USFWS, CDFG, and ACOE permits required for the project. Western may require the Applicant to prepare a Wetland Assessment, per the requirements in Title 10, Code of Federal Regulations, section 1022 (see Condition of Certification **BIO-15**).

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 a Condition of Certification and enforced with a Worker Environmental Awareness Program (see Conditions of Certification **BIO-4** and **BIO-12**).

The Applicant will also be required, as stipulated in the AFC, to implement designs for the transmission towers that prevent the electrocution of perching raptors per Energy Commission (1999) and APLIC (1996) guidelines (see Conditions of Certification **BIO-5** and **BIO-11**).

Mitigation for Cumulative Impacts

Upon implementation of habitat compensation and mitigation measures approved by the USFWS, Western, CDFG, and Energy Commission staff, the proposed project will not cause significant cumulative impacts. The proposed use of recycled water will eventually provide a beneficial decrease in the use of raw freshwater. This will minimize the potential cumulative impacts of regional projects that withdraw raw freshwater from the Delta.

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) CDFG 2081 Take Permit for state listed species;
3) A second letter of consultation with the NMFS, received June 12, 2002;
4) A CDFG Streambed Alteration Agreement, if applicable;
5) A U. S. Army Corps of Engineers Section 404 permit, if applicable; and
6) A Wetland Assessment, per the requirements in Title 10, Code of Federal Regulations, section 1022, 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-7, BIO8, BIO-9, BIO-10,** and **BIO-15**).

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 and biological monitors prior to the beginning of any project-related site mobilization. The qualified Designated Biologist and biological monitors must be familiar with the biological resource issues of the project area, as well as the Conditions of Certification and BRMIMP. The Designated Biologist and biological monitors 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 may 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-6**).

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.

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

The proposed EAEC project will result in significant and potentially significant adverse effects to biological resources. These potentially significant adverse biological impacts include the permanent loss of approximately 45 acres of wildlife habitat, for San Joaquin kit fox (and other special status species), as well as temporary habitat impacts that may result during the construction of the facility and linears. In addition, the installation of landscaping around the facility would have created a significant adverse impact to the San Joaquin kit fox. The Applicant's landscaping plan has been modified to minimize the area impacted by the landscaping and includes plant species and management practices that will reduce impacts to the kit fox. Careful selection of linear routes for gas and water pipelines has enabled the Applicant to avoid and minimize adverse biological impacts.

The significant adverse biological impacts of the EAEC project will be mitigated to less than significant levels upon:

- the successful implementation of habitat compensation through conservation and management of the entire Gomes Farms parcel;
- compliance with all required federal and state permits listed in the Conditions of Certification;
- administration of the Worker Environmental Awareness Program;

implementation of all recommended and stipulated avoidance and minimization measures; and

implementation of the BRMIMP.

The proposed project will be in compliance with LORS once all required federal and state permits have been obtained, and upon successful compliance with all permit conditions. If the project is approved, staff recommends that the following Conditions of Certification apply to the proposed project.

CONDITIONS OF CERTIFICATION

Selection of the Designated Biologist

BIO-1 The project owner shall submit the resume, including contact information, of the proposed Designated Biologist to the CPM for approval.

Verification: The project owner shall submit the specified information at least 60 days prior to the start of any site (or related facilities) mobilization. Site and related facility activities shall not commence until an approved Designated Biologist is available to be on site.

The Designated Biologist must meet the following minimum qualifications:

1. Bachelor's Degree in biological sciences, zoology, botany, ecology, or a closely related field;
2. Three years of experience in field biology or current certification of a nationally recognized biological society, such as The Ecological Society of America or The Wildlife Society;
3. 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 a Designated Biologist needs to be replaced, then the specified information of the proposed replacement must be submitted to the CPM at least ten working days prior to the termination or release of the preceding Designated Biologist.

Duties of the Designated Biologist and Biological Monitors

BIO-2 The Designated Biologist shall perform the following during any site (or related facilities) mobilization, ground disturbance, grading, construction, operation, and closure activities. These duties also pertain to the Biological Monitors.

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

2. Be available to supervise trained and approved Biological Monitors, 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 or their habitat;

3. The Designated Biologist and Biological Monitors and shall be thoroughly familiar with the Biological Conditions of Certification and the BRMIMP;

4. Clearly mark sensitive biological resource areas and inspect these areas at appropriate intervals for compliance with regulatory terms and conditions;

5. Inspect active construction areas where animals may have become trapped prior to construction commencing each day. At the end of the day, inspect for the installation of structures that prevent entrapment or allow escape during periods of construction inactivity. Periodically inspect areas with high vehicle activity (parking lots) for animals in harms way;

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

7. Respond directly to inquiries of the CPM regarding biological resource issues.

Verification: The Designated Biologist shall maintain written records of the tasks described above, and summaries of these records shall be submitted in the Monthly Compliance Reports. Qualified Biological monitors shall be approved by the CPM and training shall be verified according to procedures established in the BRMIMP including familiarity with the Conditions of Certification. During project operation, the Designated Biologist shall submit record summaries in the Annual Compliance Report.

Authority of the Designated Biologist and Biological Monitors

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

If required by the Designated Biologist or Biological Monitors, the project owner's Construction and Operation Manager shall halt all site mobilization, ground disturbance, grading, construction, and operation activities in areas specified by the Designated Biologist.

The Designated Biologist and Biological Monitors shall:

1. Require a halt to all activities in any area when determined that there would be adverse impact to biological resources if the activities continued;

2. Inform the project owner and the Construction/Operation Manager when to resume activities; and

3. Notify the CPM if there is a halt of any activities, and advise the CPM of any corrective actions that have been taken, or will be instituted, as a result of the halt.

Verification: The Designated Biologist and/or Biological Monitors must notify the CPM immediately (and no later than the following morning of the incident, or Monday morning in the case of a weekend) of any non-compliance or a halt of any site mobilization, ground disturbance, grading, construction, and operation activities. The project owner shall notify the CPM of the circumstances and actions being taken to resolve the problem.

Whenever corrective action is taken by the project owner, a determination of success or failure will be made by the CPM within five 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.

Worker Environmental Awareness Program

BIO-4 The project owner shall develop and implement a CPM approved Worker Environmental Awareness Program (WEAP) in which each of its employees, as well as employees of contractors and subcontractors who work on the project site or any related facilities during site mobilization, ground disturbance, grading, construction, operation and closure are informed about sensitive biological resources associated with the project.

The WEAP must:

1. Be developed by or in consultation with 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;
4. Present the meaning of various temporary and permanent habitat protection measures;
5. Provide an understanding of the duties and authority of the Designated Biologist and Biological Monitors;
6. Identify whom to contact if there are further comments and questions about the material discussed in the program;
7. Include a training acknowledgment form to be signed by each worker indicating that they received training and shall abide by the guidelines; and
8. The specific program can be administered by a competent individual(s) acceptable to the Designated Biologist.

Verification: At least 60 days prior to the start of any site (or related facilities) mobilization, the project owner shall provide to the CPM two (2) copies of the WEAP and all supporting written materials prepared or reviewed by the Designated Biologist and a resume of the person(s) administering the program.

The project owner shall provide 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 training acknowledgement forms shall be kept on file by the project owner for a period of at least six months after the start of commercial operation.

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

Biological Resources Mitigation Implementation and Monitoring Plan (BRMIMP)

BIO-5 The project owner shall submit to the CPM for review and approval a copy of the BRMIMP and shall implement the measures identified in the approved BRMIMP. Any changes to the approved BRMIMP must also be approved by the CPM in consultation with CDFG, the USFWS and appropriate agencies to insure no conflicts exists.

The final BRMIMP shall identify:

1. All biological resources mitigation, monitoring, and compliance measures proposed and agreed to by the project owner;
2. All Biological Resource Conditions of Certification identified in the Commission's Final Decision;
3. All biological resource mitigation, monitoring and compliance measures required in federal agency terms and conditions, such as those provided in the USFWS Biological Opinion ;
4. All biological resources mitigation, monitoring and compliance measures required in other state agency terms and conditions, such as those provided in the CDFG Take Permit and Streambed Alteration Agreement and ACOE permits;
5. All biological resources mitigation, monitoring and compliance measures required in local agency permits, such as site grading and landscaping requirements;
6. All sensitive biological resources to be impacted, avoided, or mitigated by project construction, operation and closure;

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

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

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

10. All locations on a map, at an approved scale, of sensitive biological resource areas subject to disturbance and areas requiring temporary protection and avoidance during construction;

11. Aerial photographs, at an approved scale, of all areas to be disturbed during project construction activities - one set collected prior to any site or related facilities mobilization disturbance and one set collected subsequent to completion of mitigation measures. Include planned timing of aerial photography and a description of why times were chosen;

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

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

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

15. A discussion of biological resources related facility closure measures;

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

17. A copy of all biological resources obtained permits.

Verification: At least 60 days prior to start of any site or related facility mobilization activities, the project owner shall provide the CPM with two copies of the BRMIMP for this project, and provide copies to the CDFG and the USFWS.

The CPM, in consultation with the CDFG, the USFWS and any other appropriate agencies, will determine the BRMIMP's acceptability within 45 days of receipt.

The project owner shall notify the CPM no less than 5 working days before implementing any modifications to the approved BRMIMP to obtain CPM approval.

Within 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 items are still outstanding.

Closure Plan Measures

BIO-6 The project owner shall incorporate into the planned permanent or unexpected permanent closure plan and the BRMIMP, measures that address the local biological resources.

The planned permanent or unexpected permanent closure plan shall 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 12 months prior to commencement of closure activities, the project owner shall address all biological resources related issues associated with facility closure which is incorporated into the BRMIMP in a Biological Resources Element. The Biological Resources Element shall be incorporated into the Facility Closure Plan and include a complete discussion of the local biological resources and proposed facility closure mitigation measures.

Incidental Take Permit

BIO-7 The project owner shall acquire an Incidental Take Permit from the California Department of Fish and Game (CDFG) (per Section 2081(b) of the Fish and Game Code; California Endangered Species Act) and/or a Consistency Determination (per Section 2080) and incorporate the terms and conditions into the project's BRMIMP.

Verification: At least 30 days prior to the start of any site or related facilities mobilization activities, the project owner shall submit to the CPM a copy of the final CDFG Incidental Take Permit and/or a Consistency Determination.

Streambed Alteration Agreement

BIO-8 The project owner shall acquire a Streambed Alteration Agreement from the CDFG, and incorporate the terms and conditions into the project's BRMIMP. If a Streambed Alteration Agreement is not needed for the project, the Project Owner shall submit a letter from CDFG stating their intention to not require the permit.

Verification: At least 30 days prior to the start of any site or related facilities mobilization activities the project owner shall submit to the CPM a copy of the final CDFG Streambed Alteration Agreement, or a letter from CDFG stating their intention to not require the permit.

Federal Biological Opinion

BIO-9 The project owner shall provide final copies of the Biological Opinion and any amendment addressing project changes from the U. S. Fish and Wildlife Service. The terms and conditions contained in the Biological Opinion shall be incorporated into the project's BRMIMP.

Verification: At least 30 days prior to the start of any site or related facilities mobilization activities the project owner shall submit to the CPM a copy of the U. S. Fish and Wildlife Service's Biological Opinion and any amendment.

U.S. Army Corps of Engineers Section 404 Permit

BIO-10 Upon final design of the project linear facilities, such as the recycled water line, the need for a U.S. Army Corps of Engineers (ACOE) Section 404 permit shall be determined. The project owner shall provide a final copy of the U.S. Army Corps of Engineers Section 404 permit or a letter from the ACOE stating that the Section 404 permit is not required. If the ACOE 404 permit is required, the biological resources related terms and conditions contained in the ACOE 404 permit shall be incorporated into the project's BRMIMP.

Verification: At least 30 days prior to the start of any site or related facilities mobilization activities, the project owner shall submit to the CPM a copy of the U.S. Army Corps permit, or a letter from the ACOE stating that the Section 404 permit is not required.

Preventative Design Mitigation Features

BIO-11 The project owner shall modify the project design to incorporate all feasible measures that avoid or minimize impacts to the local biological resources.

Measures that shall be implemented as appropriate include:

1. Design transmission line poles, access roads, pulling sites, and storage and parking areas to avoid identified sensitive resources;
2. Screen the water intake pipes that use natural waterways in a manner to avoid entrainment;
3. Avoid loss of wetland and riparian habitats; and
4. Design and construct transmission lines and all electrical components to reduce the likelihood of electrocutions of large birds.

Verification: All mitigation measures and their implementation methods shall be included in the BRMIMP.

Construction Mitigation Management to Avoid Harassment or Harm

BIO-12 The project owner shall manage their construction site, and related facilities, in a manner to avoid or minimize impacts to the local biological resources.

The project owner shall comply with the following measures:

Biological Mitigation Measures Proposed by Staff:

1. Appropriate avoidance and minimization measures shall be in place before site mobilization of a particular area, or activity that may impact sensitive biological resources;
2. Conduct pre-construction surveys for special status plant and animals according to USFWS, and CDFG protocols and recommendations, and in consultation with the CEC and Western. The Applicant has explicitly listed some surveys, that are listed below and detailed in the text of the FSA. The timing and duration of the surveys shall be reviewed, agreed upon and provided in the BRMIMP;
3. Clearly mark construction area boundaries with stakes, flagging, silt fencing, and/or rope or cord to minimize inadvertent degradation or loss of adjacent habitat during facility construction/modernization;
4. All equipment storage shall be restricted to designated construction zones or areas that are currently not habitat for special status species;
5. Traffic is restricted to existing roads, designated access roads, construction storage and staging areas, and parking areas;
6. Daytime construction at all drainages and drains to avoid impacts to special status reptiles, amphibians, and mammals;
7. There shall be temporary fencing and wildlife escape ramps for construction areas that contain steep walled holes, or trenches if outside of an approved, permanent exclusionary fence. The temporary fence shall be hardware cloth or similar materials that are approved by USFWS and CDFG;
8. Open trenches shall be inspected for wildlife each morning prior to start of daily construction activities. 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. Any wildlife observed shall be allowed to escape on its own if possible prior to commencement of construction. Otherwise, the Designated Biologist shall contact the appropriate agency for assistance;
9. To prevent entrapment of listed species, or other animals during construction, all excavated, steep-walled holes or trenches more than 2 feet deep shall either be covered at the close of each working day by plywood or provided with one or more escape ramps (3:1) constructed of earth fill or wooden planks. For all open trenches, an escape ramp shall be constructed at a minimum of every 0.25-mile;

10. Setbacks and buffers shall be established for the protection of special-status wildlife species. Distances shall be determined through consultation with the USFWS and CDFG prior to construction;
11. Pipes to be left in trenches overnight shall be capped;
12. Use of rodenticides shall be according to USDA label standards on-site, at the construction laydown area, and along linears. Use of rodenticides that are enclosed or otherwise protect kit fox, birds of prey, and other non-target species from becoming inadvertently poisoned;
13. Report all inadvertent deaths of sensitive species to the appropriate project representative. Injured animals shall be reported to CDFG, and the Project Owner shall follow instructions that are provided by CDFG;
14. Revegetate and maintain all linears, construction, staging, temporary parking, and equipment storage areas with CPM-approved plant species;
15. Implement pre-construction surveys raptor nests and all sensitive and special status species of animals and plants that are potentially on the project site, along linears, and at the construction laydown area within 14 days prior to commencement of any construction activities; and
16. Implement a monitoring program 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 shall be included in the BRMIMP and developed in consultation with the USFWS, Western, and CDFG.

Specific Mitigation Measures Proposed by the Applicant

17. Implement pre-construction surveys for big tarplant;
18. Implement nest surveys for Swainson's hawk within ½ mile of project features to determine use by Swainson's hawk. If project features are within ½ mile of Swainson's hawk nesting, avoid construction within ½ mile during nesting season if feasible. If construction cannot avoid active nests by ½ mile, an incidental take agreement (CDFG Section 2080.1) shall be obtained;
19. Implement pre-construction surveys for burrowing owl on the EAEC site, along linears, and the construction laydown area, followed by avoidance or passive relocation (per 1993 California Burrowing Owl Consortium Guidelines), if owls are observed;
20. Perform surveys at the appropriate time of year to identify locations of potential California Horned Lark nests within 100 feet of project features. Construction shall be avoided in the vicinity of nests;
21. Implement pre-construction surveys for tricolored blackbird within 100 feet of project features and avoid construction in the vicinity of nests;

22. Conduct pre-construction surveys for California red-legged frog and California tiger salamander and implement mitigation measures to avoid impacts to habitats for these species;
23. For San Joaquin kit fox: Obtain and comply with the conditions of a section 7 authorization for incidental take of this species. Conduct pre-design surveys for all areas potentially affected by the project. Set and enforce speed limits in the construction area at 20 miles per hour or less;
24. Implement the pre-construction surveys for San Joaquin kit fox, and construction practices and mitigation measures as outlined in *Standardized Recommendations for Protection of the San Joaquin Kit Fox Prior to or During Ground Disturbance* (USFWS 1999);
25. Provide safety lighting that points downward on the HRSG stacks to reduce avian collisions;
26. Lease the 134-acres of land surrounding the EAEC for use in wildlife-friendly agriculture (per USFWS and CDFG guidelines); and
27. Implement a red fox control program.

Verification: All mitigation measures and their implementation methods shall be included in the BRMIMP. The Project Owner shall provide a post-construction compliance report, within 30 calendar days of completion of the project, to the Energy Commission CPM.

Compensation for Loss of Habitat

BIO-13 Prior to the start of site mobilization for the project and any related facilities, the project owner shall provide a conservation easement on the 151-acre Gomes Farms parcel. The Gomes Farms habitat provides suitable habitat for the San Joaquin kit fox, burrowing owl, Swainson's hawk, California tiger salamander, and California red-legged frog. If the project owner causes impacts to additional acres of habitat during construction or operation of the project they shall be required to mitigate for those impacts with additional habitat compensation, at a ratio of 3:1 for permanent impacts and 1:1 for temporary impacts, at the Haera mitigation bank or other location to be approved by the CPM in consultation with the USFWS, CDFG, and Western.

The conservation easement on the Gomes Farms parcel shall be approved through CDFG or an entity approved by CDFG and will remain in effect in perpetuity. CDFG or an entity approved by CDFG will hold the conservation easement and the endowment. The project owner shall provide a Property Assessment Report (PAR) analysis for establishment of an endowment to provide for the long-term management of the habitat lands. The third party management agency shall receive the endowment funds through CDFG or an entity approved by CDFG. Selection of the third party management agency and management procedures for the conservation easement lands must be approved by the CPM in consultation with the USFWS, CDFG, and Western.

Verification: At least 30 days prior to the start of site mobilization on the project site or any related facilities, the project owner shall provide the CPM with a copy of the complete conservation easement agreement pursuant to this Condition of Certification. Upon completion of the acquisition and transfer, if applicable, of the habitat lands (include county parcel #) to the approved recipient(s), the project owner shall provide the CPM with copies of all title transfer records or records verifying other approved transactions. The Project Owner must provide to the CPM for approval, the name of the management entity, and written verification that the appropriate endowment fund (determined by the PAR analysis) has been received by the approved management entity.

Each month, the project owner shall provide information on additional planned or unplanned impacts to habitats that will be permanently or temporarily by the project. The project owner shall provide information at least 30 days prior to incurring the impacts for planned impacts and within 30 days of incurring the impacts for unplanned impacts. Each month, the Designated Biologist shall prepare, as part of the monthly compliance report, a detailed description and evaluation of any additional habitat impacts. The report shall include appropriately scaled and detailed maps, the number of acres to be impacted or already impacted, the types of habitat(s) impacted and any impacts to special status species. Within 30 days of the completion of construction, the project owner shall submit a final report on all additional acres impacted, if any. In this report, the project owner shall provide evidence of consultation with the CPM, USFWS, and CDFG to confirm the location and acreage of habitat compensation to be provided at the approved mitigation ratio. If no additional habitat acres are impacted, then no additional habitat mitigation shall be required.

Refuge Burrows for San Joaquin Kit Fox

BIO-14 The Project Owner's Landscape Plan submitted on April 3, 2002 shall be approved after licensing and implemented as approved (refer to Condition of Certification **VIS-3**). The final landscaping design shall be approved by Energy Commission staff in consultation with the USFWS, CDFG, and Western. In order to protect San Joaquin kit fox from predators and competitors that may benefit from the landscaping, and to generally minimize adverse impacts to the kit fox, the Project Owner shall install artificial refuge dens underneath the landscaping and around the perimeter of the facility. The spacing and size of the dens shall be determined in consultation with CDFG and USFWS and shall be included in the BRMIMP. A monitoring plan concerning the use of the dens shall also be developed and implemented in consultation with CDFG, USFWS, and Western and shall be included in the BRMIMP.

Verification: The approved Landscaping Plan and San Joaquin kit fox den installation and monitoring plan shall be attached to the BRMIMP and shall be submitted to the CPM for approval at least 60 days prior to the start of any site or related facility mobilization activities.

Wetland Assessment per Title 10, Code of Federal Regulations, Section 1022

BIO-15 Upon final design of the project linear facilities, the need for a Wetland Assessment, per the requirements in Title 10, Code of Federal Regulations, section 1022 , shall be determined by Western. The project owner shall provide a final copy of the Wetland Assessment that shall be reviewed and approved by Western. The biological resources related terms and conditions contained in the Wetland Assessment shall be incorporated into the project's BRMIMP. If the Wetland Assessment is not required, the project owner shall provide the CPM with a letter from Western stating that the assessment is not required.

Verification: At least 45 days prior to the start of any site or related facilities mobilization activities, the project owner shall submit to the CPM a copy of the Wetland Assessment, or a letter from Western stating that the Wetland Assessment is not necessary.

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CULTURAL RESOURCES

Testimony of 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 resources analysis for this project is to ensure that all potential impacts 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 that will reduce any potential 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 4321 et seq., requires federal agencies to consider potential environmental impacts of projects with federal involvement and to consider appropriate mitigation measures.

Title 36, Code of Federal Regulations, section 61, Federal Guidelines for Historic Preservation Projects: The U. S. 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 California 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, section 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.

Title 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 take 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 (CRHR).

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 provides for the repatriation of certain items from the federal government and certain museums to the native groups to which they once belonged. However, the provisions for repatriation only apply to items found on federal lands or Indian lands. The act also defines "cultural items," "sacred objects," and "objects of cultural patrimony"; and it establishes a means for determining ownership of these items.

National Environmental Policy Act of 1969 (NEPA; Title 42, United States Code, sections 4321-4347). This act requires federal agencies to consider the 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.

Title10, 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

California Code of Regulations, Title 14, section 4852 defines the term "cultural resource" to include buildings, sites, structures, objects, and historic districts.

Public Resources Code, Section 5000 establishes a California Register of Historic Places; determines significance of and defines eligible resources. It identifies any unauthorized removal or destruction of historic resources on sites located on public land as a misdemeanor. It also prohibits obtaining or possessing Native American artifacts or human remains taken from a grave or cairn and establishes the penalty for possession of such artifacts with intent to sell or vandalize them as a felony. This section defines procedures for the notification of discovery of Native American artifacts or remains, and states that it is the policy of the state that Native American remains and associated grave artifacts shall be repatriated.

The California Environmental Quality Act (CEQA) (Public Resources Code, section 21000 et seq.; Title 14, California Code of Regulations, section 15000 et seq.) requires analysis of potential environmental impacts of proposed projects and requires application of feasible mitigation measures.

Public Resources Code section 21083.2 states that the lead agency determines 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 “historic resource” and describes what constitutes a “significant” historic resource.

CEQA Guidelines, Title 14, California Code of Regulations, section 15126.4(b), prescribes the manner of maintenance, repair, stabilization, restoration, conservation, or reconstruction as mitigation of a project’s impact on a historical resource. It also discusses documentation as a mitigation measure; and 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, section 15064.5 defines the term “historical resources,” explains when a project may have a significant effect on historic resources, describes CEQA’s applicability to archaeological sites, and specifies the relationship between “historical resources” and “unique archaeological resources.”

Penal Code, section 622 1/2 states that anyone who willfully damages an object or thing of archaeological or historic interest is guilty of a misdemeanor.

California Health and Safety Code, section 7050.5 states that if human remains are discovered during construction, the project owner is required to contact the county coroner.

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 NRHP and the CRHR 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 pipelines) 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, p. 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 32 degrees less than fifteen days per year. The average period between the last frost of spring and the first frost of fall is more than 7.5 months (Simonds 1994). 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. A linear route crosses 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 Final 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, pp.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, social stratification (indicated by variability in grave goods), and elaborate ceremonialism (Moratto 1984, p. 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, p.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, p.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, p.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. During the 1860s, Wicklund had a hotel, blacksmith shop, warehouse, and coal bunkers (Baker et al. 1991).

Wicklund originated and thrived as a town on the Old River. Steamers transported coal and grain to San Francisco. 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, p.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, p. 13). Mountain House was another nineteenth century settlement near the project area (EAEC 2001s, p.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, p. 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, p. 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 California State University, Stanislaus 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 were 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 portion of the gas line route along 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. The site is about one mile from the project area.

The other prehistoric archaeological site (P-39-000254) is located in San Joaquin County along Mountain House Creek in the vicinity 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. A geoarchaeological study completed by the applicant's consultant confirmed that there is a potential for buried prehistoric archaeological resources in the part of the project area where the reclaimed water line route crosses Mountain House Creek (Meyer 2002:8). The alluvial fan deposits in this area date to the early Holocene (the period after the end of the ice age when Native Americans likely first occupied the area) and a buried surface was observed in the bank of a canal that runs through this area. The presence of the buried surface indicates that a surface possibly used by Native Americans exists in the area and may be revealed by ground disturbance.

The records search results showed that 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 these counties 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 about 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 the recorded boundaries of these resources from the historic period, based on surface evidence, 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 (adjacent to the route of the reclaimed water line) 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 water line route crosses 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. These and other linear resources of historic age are discussed further 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 houses 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 2001u, 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

Archaeological 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 water line route, the reclaimed water line route, and a portion of the gas line route (EAEC 2002b, p. 24). The survey of the power plant property was performed by walking parallel 20 meter transects and 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 2002b, p.24-25). No archaeological resources were identified as a result of these surveys (EAEC 2002b, p. 25-27).

The reclaimed water line route does not pass through the area recorded as the town site of Wicklund (P-39-000343), based on surface evidence, but passes within 75 meters of this site. The proximity of the reclaimed water line route to the town site indicated some potential for impacts to subsurface deposits associated with the town site as a result of excavation for installation of the reclaimed water pipeline. Therefore, staff requested a subsurface test to determine whether subsurface deposits from the historic period were present in the route of the reclaimed water line. Five trenches 18 inches wide and seven feet deep were excavated with a backhoe in the reclaimed water line route. This depth extended below the proposed impacts from the pipeline which will be installed at a depth of three to four feet below surface. All of the sediments exposed in the trenches consisted of culturally sterile fill which likely resulted from excavating the adjacent Wicklund Canal and were deposited here to form a berm along the canal. No cultural material was encountered in any of the trenches (McClintock 2002).

Historical Surveys

Staff requested that the applicant also provide a survey of historic resources (structures and buildings from the historic period), 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 produced, that adequately addressed the presence and significance of 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 (PAR Environmental Services [PAR], 2002). The survey and inventory included structures and linear resources that had not been previously recorded and that were located within an approximately one mile radius of the power plant. This area included properties that could have their setting impacted by construction of the power plant. Photographs were taken and DPR 523A forms were completed for 28 properties. Historical research was performed for 18 of the 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 28 inventoried properties are identified in Table 1 (PAR 2002). The following discussion is a brief summary of the inventoried resources identified in Table 1. Linear resources identified, 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 Southern Pacific Railroad Grade is the rail line between Tracy and Martinez and 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 Mountain House with the wider region. It was straightened and realigned in 1889. The road is now a paved two lane county road.

Table 1Cultural 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	1878			X
3	Mountain House Road (segment)	circa 1874			X
4	Hurley-Tracy Transmission Line (segment)	1951			X
5	Tracy-Contra Costa-Ygnacio Transmission Line (segment)	circa 1946-1951			X
6	Tracy-Los Vaqueros Transmission Line (segment)	circa 1946-1951			X
7	PG&E Distribution Line	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
11a	Tracy Pumping Station 16650 Kelso Rd.	1952		X	
11b	Tracy Switch Station 16800 Kelso Road	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 Rd.	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	

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 Station (Resource No. 11a), the Tracy Switch Station (Resource No. 11b), 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 Sacramento 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 Switch Station by the Hurley-Tracy Transmission Line for use by the Tracy Pumping Station. 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 Station consists of four structures. One of these is a large metal structure over the Intake Channel which houses the pump equipment. The other buildings consist of a two story concrete office building, a one story concrete office building, and a metal clad storage building. The Tracy Pumping Station was completed in 1952 and has not been modified. The Tracy Switch Station is adjacent to the pumping station and consists of 14 buildings and electrical transmission switching yards. The buildings are mostly one story metal clad structures, although the office has wood siding. The complex also has metal electrical switching equipment and transmission towers. The Tracy Switch Station was also completed in 1952, but many of the present buildings were added in the 1960s and 1990s. New transmission lines and switching equipment also have been added. The transmission lines are supported by standard design latticed steel towers set on concrete piers. The original transmission lines (the Hurley-Tracy Transmission Line, the Tracy-Contra Costa-Ygnacio Transmission Line, and the Tracy-Los Vaqueros Transmission Line) have a capacity of 230 kv and all three 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 when completed in 1919, but some sections are now concrete lined. 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 Patteson 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 Patteson 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. Patteson, 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. 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. Currently, there are a house, a barn, and two sheds on the property. The single story house has several extensions which appear to be later additions. All original windows have been replaced with aluminum slider windows.

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 have been sent notices regarding public workshops. Native Americans have also been sent letters requesting that they contact staff if they have concerns regarding any impacts to archaeological or sacred sites from the project.

Members of the Santa Rosa Rancheria, a federally recognized tribe, requested that Western ensure that an ethnographic study of the project area be completed. The purpose of the study is to provide an overview of Native American use of the project area and to identify any traditional cultural properties within a three-mile radius of the project. Staff has requested the ethnographic study and the applicant has agreed to fund the study. It will be performed by the Department of Anthropology at California State University, Fresno.

The study will include an ethnographic background report for the project area. Consultation with Nototomne Yokuts, Tachi Yokuts/Santa Rosa Rancheria and other interested groups identified through information from the NAHC will provide information for the study. It will conclude with recommendations for treatment of human remains or unanticipated discoveries and additional work, if necessary (EAEC 2002ddd, p.8).

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:

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 evaluated the survey reports and site records for any known resources located within or adjacent to the project impact area 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). Where staff has determined that the sites for which it is recommending mitigation meet the definition of historical resources, the prohibition does not apply.

The original historic survey conducted by the applicant did not identify any resources of historic age 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. Subsequent to this survey, the applicant obtained the services of a qualified historian to evaluate the PG&E Distribution Line, the Tracy Pumping Station, and the Tracy Switch Station. The applicant evaluated the PG&E Distribution Line as not eligible for the National Register of Historic Places. Although staff requested that the Tracy Pumping Station and the Tracy Switch Station be evaluated as separate properties, the applicant’s consultant evaluated them as one property and concluded that, because the switch station had lost integrity during numerous recent additions (buildings and switching equipment), the entire complex (the Tracy Pumping Station and the Tracy Switch Station) is not eligible for the NRHP.

The evaluations of the PG&E Distribution Line, the Tracy Pumping Station, and the Tracy Switch Station, provided by the applicant met the requirements for evaluating historic resources provided in CEQA and NHPA. A prior evaluation of historic structures provided by the applicant was inadequate, since it based all evaluations on potential age, focused on appearance of the 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 within one mile of the project site and linears. Results differed

considerably from those of the applicant. This historian inventoried 28 properties identified as 45 years or older (Table 1) and evaluated 18 of them using NRHP and CRHR criteria (see the discussion of NRHP and CRHR eligibility criteria in the Categorization of Identified Cultural Resources section). The consultant recommended three historic resources in the project area as eligible to both the NRHP and the CRHR. The historical resources evaluated as eligible are a segment of the Delta Mendota Canal and Intake Channel, the Tracy Pumping Station, and the Westside Irrigation District Complex. The Delta Mendota Canal retains integrity and is eligible under Criterion A as part of the Central Valley Project because it contributed to the broad historic pattern of the development of the state-wide water control public works program and the development of agricultural operations and communities throughout California's inland valleys. It is eligible under Criterion C because it is an excellent example of a revolutionary scale of canal construction. The Tracy Pumping Station is eligible under Criterion A also because it retains integrity and was part of the CVP. The pumping station is also eligible under Criterion C because the massive size of the pump made it unique in California at the time. The Westside Irrigation District Complex retains integrity and is eligible under Criterion A because it is the oldest intact example of the development of regional irrigation districts which altered farming practices and led to increased economic and residential development.

While eligibility determinations for the NRHP must be made by the lead federal agency (in this case, the Western Area Power Administration) with the concurrence of the State Historic Preservation Officer (SHPO), Energy Commission staff concurs that the Delta Mendota Canal and Intake Channel, the Tracy Pumping Station, and the Westside Irrigation District Complex resources are eligible for the CRHR. Western will recommend to the SHPO that Delta Mendota Canal and Intake Channel and the Westside Irrigation District Complex are eligible to the NRHP. They will recommend the Tracy Substation including the Tracy Pumping Station as not eligible to the NRHP based on the fact that they were constructed at the same time and there is loss of integrity. PAR recommends that the Tracy pumping station is eligible to the CRHR under criterion C. Eligibility is based on the pumping station's relation to the Delta Mendota Canal, the CVP and its massive size. Energy Commission staff concurs with this assessment.

The PG&E Distribution Line and Substation is not eligible for the CRHR under Criterion A because it was constructed as a small line to distribute electricity off the main line and was not significant in the overall transmission system at the time, nor was it the first such line. It is not associated with any historically significant person and, therefore, is not significant under Criterion B. It is not significant under Criterion C because it is not technologically unique and is an example of a common design ubiquitous across the United States.

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 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. These other resources also 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). Therefore, staff finds that they are not eligible for the CRHR.

Potential cultural concerns raised by Native Americans at the Santa Rosa Rancheria will be addressed by an ethnography of the project area, which is required in condition of certification Cul-6.

ANALYSIS AND IMPACTS

Since project development and construction usually entail surface and subsurface disturbance, the proposed East Altamont Energy Center 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 footprint. 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 and the results of the geoarchaeological study indicate 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. The results of the backhoe test near the town site of Wicklund (P-39-000343) showed that construction of the reclaimed water line would not impact subsurface deposits associated with this site. However, there is a potential to encounter buried resources from the historic period during construction of the reclaimed water line in the vicinity of the town site of Bethany and historic archaeological site P-39-000345. If archaeological sites are encountered during construction and are evaluated as eligible for the CRHR or the NRHP, impacting these sites would result in a significant impact and an adverse effect, unless mitigated.

Historical Structures and Infrastructure

Construction of the water line from Mountain House Road to Bruns Road will cross the intake channel portion of the Delta Mendota Canal and Intake Channel. Construction of the water line could impact the canal, depending upon the construction method. The applicant plans to use directional drilling to bore under the Delta Mendota canal (EAEC 2001a, pp. 7-13). Use of this construction method will not result in any significant impacts to the canal.

Construction of the power plant and associated pipeline and transmission lines will not physically affect the Tracy Pumping Station. However, construction of the EAEC could change the setting of the Tracy Pumping Station. If construction of the EAEC would materially alter the surroundings (setting) to the point that the property's historical significance would no longer be conveyed and, therefore, the property would no longer be eligible for the CRHR, impacts to the setting of the Tracy Pumping Station would be significant (CEQA Guidelines Section 15064.5[b1, b2]). However, since the Tracy Pumping Station is already in an industrial setting with the Tracy Switch Station and numerous transmission lines and towers directly adjacent, construction of the energy center would add more industrial facilities nearby. The addition of industrial facilities, would not materially alter the surroundings (setting) to the point that the property's historical significance would no longer be conveyed. Therefore, impacts on the Tracy Pumping Station from construction of the EAEC will not be significant.

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.

CUMULATIVE IMPACTS

Cumulative impacts to cultural resources in the project vicinity may occur if subsurface archaeological deposits (both prehistoric and historic) 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 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, impacts 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 Title 36, Code of Federal Regulations, section 800 and the National Environmental Policy Act. Western will consult with the State Historic Preservation Officer to fulfill their responsibilities under the NHPA.

After all requested documents are received by Western, they will provide the necessary documentation concerning cultural resources to the SHPO.   The SHPO will review and comment within 30 days. If additional information is necessary or if there is no agreement regarding the outcome, Western will provide that information or an explanation and the SHPO will have an additional 30 days to respond. Western's obligation to consult with the SHPO will have no additional impacts on the Energy Commission's permitting process.

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 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 on a 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. 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.

Cultural Concerns

The applicant did not suggest mitigation for Native American cultural concerns.

STAFF'S PROPOSED MITIGATION MEASURES

Commission staff concurs with the mitigation measures proposed by the Applicant for archaeological resources, but recommends defining the area where full time monitoring will take place. Full time monitoring would take place during construction of the reclaimed water line for 1,000 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 along a portion of Byron-Bethany Road and along Bethany Road. Monitoring should begin 1,000 feet northwest of the intersection of Byron-Bethany Road and Mountain House Creek and end at the intersection of Bethany Road and Wicklund Road.

Proposed conditions of certification ensure that impacts to known resources and potential impacts to unidentified cultural resources would be mitigated below a significant level. In summary, the conditions ensure compliance with the following requirements. Condition one, **CUL-1** requires that a qualified cultural resources specialist manage cultural resources activities for the project. It also ensures that additional qualified specialists or cultural resources monitors would be retained as needed for the project. To ensure that cultural resources are adequately protected, CUL-1 requires that the CRS have three years of experience in California. In addition to other relevant types of experience, the condition requires that the CRS have some background in data recovery, including sampling for dating and botanical studies and small artifact recovery. A background in botanical studies is important because techniques for analyzing plant remains yield information regarding the human use of plants. It is also important in identification and understanding the traditional uses of plants by Native Americans. Experience in sampling for dating is important because archaeologists need to be able to fit discovered materials into chronological frameworks. All excavations need to be adapted to the research question at hand and to the nature of the site. A broad base of particular kinds of experience is necessary for a cultural resources specialist leading an excavation.

CUL-2 provides the CRS with the necessary maps and construction schedule information necessary to schedule monitors and cultural resources activity at the project site. The verification for the condition allow staff to verify that the maps and construction schedule information have been provided to the CRS and meet the needs of that project.

Moreover, a plan for treatment of previously identified cultural resources and a method for addressing the potential for encountering undiscovered resources will be provided by the Cultural Resourses Specialist (CRS) pursuant to conditions of certification **CUL-3**. The Cultural Resources Monitoring and Mitigation Plan (CRMMP) addresses, but is not limited to areas that will be monitored. In the event cultural resources are discovered, they will be recorded on Department of Parks and Recreation form, DPR 523. According to direction provided by the Office of Historic Preservation (OHP) in "Instructions for Recording Historical Resources" in general a broad threshold is set for the kinds of resources that may be recorded. "Any physical evidence of human activities over 45 years old may be recorded for purposes of inclusion in the OHP's filing system. Documentation of resources less that 45 years old also may be filed if those resources have been formally evaluated, regardless of the outcome of the evaluation" (OHP 1995, p.2). The CRMMP also provides the reporting requirements between construction personnel, the CRS's and cultural resources staff.

Although not required or discussed in this condition, staff has developed (in draft form) a programmatic treatment plan. The purpose of this agreement is to identify in advance, cultural resources that may be treated in a programmatic manner under the agreement. Staff invites the CRS to identify cultural resources that may be discovered that would not meet the criteria of the CRHR. If staff and the CRS reach agreement, then the CRS need not notify the Energy Commission when a particular cultural resource or category of cultural resources that are identified for programmatic treatment is discovered.

CUL-4 provides for worker environmental training. The training serves to instruct workers that halting construction is necessary if a potential cultural resource is discovered. It also provides them with instruction regarding applicable laws, penalties and reporting requirements in the event something is discovered. Workers are also instructed that the CRS and other cultural resources personnel have the authority to halt construction in the event of a discovery.

CUL-5 requires notification of staff within 24 hours of a cultural resources find. Timely notification enables staff participation in determinations of significance and the selection of appropriate mitigation to lessen impacts on cultural resources to a level that is less than significant.

CUL-6 ensures that cultural resources monitoring activities are conducted in a manner that would identify cultural resources and provide useful technical information recorded in monitoring logs. Archaeological monitoring is recommended on this project because geotechnical investigation has identified the potential for subsurface sites in the vicinity of project linears. **CUL-6** specifies that cultural resources monitoring be conducted during periods of initial ground disturbance. Initial ground disturbance as it is used in this condition, means the first time grading or excavation are undertaken at the project site and at each linear. The CRS will examine subsurface soils and determine whether continued monitoring is warranted at the project site or on each linear. The CRS will then proceed in compliance with the remainder of the condition.

It is not possible to determine whether previously undiscovered cultural resources may be potentially significant. It is necessary to discover the cultural resource and assess it in relation to a research design (required in **CUL-3**) and the criteria that would make eligible to the CRHR or NRHP. Therefore, it is not possible to allocate monitoring to situations where there is a potential to discover significant cultural resources. In addition, **CUL-6** ensures that unanticipated impacts to cultural resources are identified and that any incidence of non-compliance with the conditions of certification are recognized, reported and compliance attained in a timely manner.

Furthermore, **CUL-6** requires that a weekly report written by the CRS based on information provided in the monitoring logs be provided to the CPM in the Monthly Compliance Report (MCR). If a non-compliance issue is identified, **CUL-6** requires that a report written no sooner than two weeks following resolution of a non-compliance issue be submitted in the next MCR. This is to allow the CRS time to resolve the issue and prepare a report.

CUL-7 ensures that a scope of work and research design are developed and approved by the CEC and Western prior to beginning data recovery or other mitigation. Issues regarding the determination of significance (based in part on the research design prepared for **CUL-3**) would be informally discussed on the telephone at the time a determination of significance is discussed. After the determination of significance is made (for Western this will involve consultation with the SHPO), a document is prepared to explain how data recovery or other mitigation would proceed. The document provides information to staff to ensure that the mitigation would reduce the impact of the project on the cultural resource to less than significant levels. Western would submit the document to the SHPO for concurrence in order for data recovery to begin.

CUL-8 requires that a report be prepared following any cultural resources discovery. The report will inform Western and staff regarding the cultural resource and would supply Western with a document to submit to the SHPO to complete consultation requirements under section 106. It also requires a final cultural resources report (CRR) prepared to Archaeological Resource Management Report (ARMR) Guidelines. The report would be designed to address all cultural resources activity conducted for the project, whether or not anything new was discovered.

CUL-9 requires the curation of cultural materials collected as a result of project activity. “Guidelines for the Curation of Archaeological Collections” 1993, available on the Office of Historic Preservation Website, recommends that prior to a historic or prehistoric resource survey, study or excavation, the collection strategy should be stated in the research design (**CUL-3**) and approved by the lead agency.

Staff recommends installation of the water line under the Delta Mendota Canal by boring. Use of this construction method will not cause a significant impact to 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

Based on the geoarchaeological study conducted by the Applicant, Western recommends monitoring during ground disturbance in the vicinity of the reclaimed water line. The monitoring will occur 1,000 feet on each side of the reclaimed water line’s intersection with Mountain House Creek (McClintock:2002). 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 (NRHP eligibility) can be evaluated. If evaluated as significant, mitigation measures (avoidance or data recovery) would be developed in consultation with Western.

The Delta Mendota Canal and the Westside Irrigation District have been recommended as eligible for inclusion in the NRHP. There will not be any impacts to the Westside Irrigation District and boring under the Delta Mendota Canal will successfully mitigate any impacts.

Cultural concerns raised by Native Americans at the Santa Rosa Rancheria, a federally recognized tribe, will be addressed by an ethnography of the project area, prepared by anthropologists from California State University, Fresno.

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 and will reduce impacts 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.

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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 36, section 61 (2000).

   a. 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

   b. The background of the CRS shall include at least three years of archaeological or historic, as appropriate, resource mitigation and field experience in California;

   c. and at least one year's experience in each of the following areas:

      i. principal investigator for archeological field surveys;

      ii. principal investigator for site mapping and recording;

      iii. principal investigator for site testing and data recovery, including sampling for dating and botanical studies and small artifact recovery;

      iv. principal investigator for laboratory studies of collected materials; and

      v. preparing reports for a curation repository, the State Historic Preservation Officer, and the appropriate regional archaeological information center(s).

2. familiar with the CRS's work on referenced projects.

3. 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.

4. The CRS may obtain qualified cultural resource monitors (CRMs), as necessary, to monitor on the project. CRMs shall meet the following qualifications.

   a. A BS or BA degree in anthropology, archaeology, historic archaeology or a related field and one year experience monitoring in California; or

   b. An AS or AA in anthropology, archaeology, historic archaeology or a related field and four years experience monitoring in California; or

   c. 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.

5. 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).

<u>Verification :</u> At least 90 days prior to the start of ground disturbance, the project owner shall submit the name and resume of its CRS and alternate CRS, if an alternate is proposed, to the CPM for review and approval. 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.

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.

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) If not previously submitted, 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 provided to the CRS on a weekly basis during ground disturbance and provided to the CPM in each Monthly Compliance Report (MCR).

Verification: At least 75 days prior to the start of ground disturbance, the project owner shall provide the designated CRS and the CPM with the maps and drawings. If this is to be a phased project, a letter identifying the proposed schedule of construction phases of the project shall also be submitted. If not previously submitted, 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.

CUL-3 Prior to the start of ground disturbance; the designated CRS 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.

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 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.

Verification: At least 60 days prior to the start of ground disturbance, the project owner shall provide the CRMMP, 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 The project owner shall provide in the Monthly Compliance Report the WEAP Certification of Completion form of persons who have completed the training in the prior month and a running total of all persons who have completed training to date.

CUL-5 The CRS, alternate CRS and the CRM(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 CRM(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 Cultural resource monitoring shall be conducted full time during ground disturbance necessary for construction of the reclaimed water line along a portion of Byron-Bethany Road and along Bethany Road. Monitoring should begin 1,000 feet northwest of the intersection of Byron-Bethany Road and Mountain House Creek and end at the intersection of Bethany Road and Wicklund Road.

1. Cultural resources monitoring shall be conducted during initial ground disturbance 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 disturbance 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 or e-mail 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 the area of the reclaimed water line where cultural resources monitoring shall occur full time, per this condition. Native American monitoring shall also occur during any cultural resource monitoring for the project, including investigation of initial ground disturbance and spoils and data recovery, if data recovery is necessary. 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.

5. At least 30 days prior to ground disturbance, the project owner shall ensure that an ethnography is initiated on behalf of Native Americans at the Santa Rosa Rancheria. The ethnography, shall include, but not necessarily be limited to the proposed scope of the study, provided as a response to Data Request Responses Set No. 6, Cultural Resources No.155. The scope of the study will focus on lands within a 3-mile radius surrounding the project area. Consideration of a larger area shall be included to allow discussion of historic interaction between Bay Miwok and Northen Valley Yokuts people. Primary tasks will include preparation of an ethnographic report for the project area. Consultation with Nototomne Yokuts, Tachi Yokuts/Santa Rosa Rancheria and other interested groups as identified through the consultation with the Native American Heritage Commission. The report shall also provide recommendations, if applicable. A copy of the scope of work and a summary of achieved objectives shall be provided to the CPM

and Western for review and approval. A copy of the completed ethnography shall be provided to Western and the CPM for review and approval.

Verification: 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.

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.

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.

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.

No later than 30 days after the start of ground disturbance, a copy of the scope of work of the ethnography and a summary of achieved objectives shall be submitted to the CPM and Western for review and approval. No later than 90 days after the initial ground disturbance, a copy of the completed ethnography shall be provided to Western and the CPM for review and approval.

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.

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.

Verifications: The project owner shall ensure that the CRS prepares and submits the research design and scope of work within 14 days 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 CRS 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.

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.

Although, no cultural resources are identified as a result of the project, a CRR shall be prepared that address the entire project. The proposed 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 all 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 approval. Western will submit the report, when approved, to the State Historic Preservation Officer in order to complete consultation under Section 106.

Whether or not 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 CRS shall provide a copy of a curation agreement from a public repository that meets the requirements set out in Title 36, CFR section 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

Testimony of 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 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. Anhydrous ammonia has high internal energy when 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.

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 due to the 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 1.8 miles in length including on and off-site segments (EAEC 2002a).

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.

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 Alameda County Department 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.

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, that characterize the surrounding land. The pipeline classes are defined as follows (Title 49, Code of Federal Regulations, Part 192):

Class 1: Pipelines in locations within 220 yards of ten or fewer buildings intended for human occupancy in any 1-mile segment.

Class 2: Pipelines in locations within 220 yards of more than ten but fewer than 46 buildings intended for human occupancy in any 1-mile segment. This class also includes drainage ditches of public roads and railroad crossings.

Class 3: Pipelines in locations within 220 yards of more than 46 buildings intended for human occupancy in any 1-mile segment, or where the pipeline is within 100 yards of any building or small well-defined outside area occupied by 20 or more people on at least 5 days a week for 10 weeks in any 12 month period (the days and weeks need not be consecutive).

Class 4: Pipelines in locations within 220 yards of building s with 4 or more stories above ground in any 1-mile segment.

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, that 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 adopted 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 currently 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, 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 are appropriate assumptions for use in the modeling of an accidental release. Staff believes these assumptions correspond to a reasonably conservative scenario that reflects worst case atmospheric conditions. The location of elevated terrain (terrain above the power plant stack height) is often an important factor to be considered in assessing potential exposure. The emissions 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 on the elevated terrain to the west. However, these hills contribute to the persistent winds in the project vicinity and would thus contribute to the rapid dispersion and transport of ammonia from the property in the event of a storage tank rupture.

The general population in the project vicinity 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 the location of the closest sensitive receptor in the project vicinity. The 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 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.

PROJECT IMPACTS

Storage and Use of Small Quantity Hazardous Materials

In conducting the analysis, staff determined in Steps 1 and 2 that most of the hazardous materials proposed for use at the EAEC 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, including construction of the linear facilities, 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 proposed use of hydrogen gas poses a risk of explosion. However, the amounts that will be present pose no risk of off-site blast effects. Figure 8.12-1 from the AFC indicates that the proposed location for the hydrogen trailer would be about 75 feet from the combustion turbine generator of the eastern most generating unit. Proposed Condition of Certification **HAZ- 11** requires storage of the hydrogen cylinders in an area isolated from combustion sources and away from potential damage of a turbine over speed event. The tanks and piping that are near potential traffic hazards will be protected from vehicle impact by traffic barriers.

After removing from consideration those chemicals that fit into Steps 1 and 2, staff continued with Steps 3, 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.

Storage and Use of Large Quantity Hazardous Materials

Sodium hydroxide, anhydrous ammonia, and sulfuric acid will be present in excess of the Reportable Quantity (RQ) and therefore must be included in the Hazardous Materials Business Plan (HMBP). Although not reportable, sodium hypochlorite will also be present in large quantities. Hydrochloric acid (HCl) will be present at the site in large quantities once every three to five years and at start-up, but is not stored on site. During the typical operating periods, HCl will be stored in quantities less than the RQ.

Sodium Hydroxide

Sodium hydroxide is a strong base that is used in water treatment. It has a very low vapor pressure and therefore poses no risk of atmospheric transport off-site. Sodium hydroxide does pose a risk of soil and water contamination. However, it will be stored within an impervious secondary containment structure that will prevent such contamination. It is staff's conclusion that use of sodium hydroxide poses no risk of impacting surrounding populations in the event of an accidental release at the facility.

Sulfuric Acid

Sulfuric acid would not pose a risk of off-site impacts, because it has a relatively low vapor pressure and thus emissions from spills would be confined to the site. 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, should a fire occur in the immediate vicinity of the sulfuric acid tank, the potential exists for the tank to rupture and for sulfuric acid to become vaporized and migrate off-site. In order to protect against risk of fire causing this accidental release, an additional Condition of Certification (**HAZ-5**) requires the project owner to ensure that no combustible or flammable materials would be stored or used within 100 feet of the sulfuric acid tank. There are no combustible materials proposed to be stored 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.

Hydrogen Gas

Staff has some concerns regarding the location of the hydrogen gas cylinder trailer and its proximity to the turbine and other hazardous materials. The proposed location of the ammonia tank and unloading facility is between the nitrogen and hydrogen tanks, less than 50 feet from each of the neighboring tanks. The potential hazard of the close proximity of the hydrogen tanks with regard to flammable and toxic materials hazards would be mitigated by implementation of proposed Condition of Certification **HAZ-11**.

Hydrochloric Acid

In the case with HCl, the infrequent use (10,000 pounds once every three years) poses a small risk of accidental release. While an accidental release of HCl would not cause any potential for significant impact off-site, it could adversely affect plant personnel. In order to reduce the size of any pool potentially resulting from a spill, staff proposes Condition of Certification **HAZ-12** requiring the applicant to erect portable berms to keep any spill contained to a small area.

Sodium Hypochlorite

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 in the AFC (Section 8.6.3.3) the Applicant proposes to separate incompatible materials to prevent accidental mixing and provide separate containment facilities for each material.

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 1996), natural gas is very difficult to detonate and virtually never causes the type of unconfined explosions that are often associated with 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. Explosions involving natural gas can occur in combustion equipment such as 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 further reduce the potential for equipment failure and explosion or fire 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 were also be evaluated. Current design codes require use of high quality arc welding techniques by certified welders and inspection of welds. Many failures of older natural gas lines have been associated with poor quality welds or corrosion. Current codes address 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 earthquakes. 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, occurred as a result of pipeline corrosion, pipeline construction or materials defects, rupture by heavy equipment excavating in the area such as bulldozers and backhoes, weather effects, and earthquakes. Given the gas line failures which occurred in the Marina District of San Francisco during the 1989 Loma Prieta earthquake, the January 1994 Northridge earthquake in Southern California, the January 1995 gas pipeline failures in Kobe, Japan, 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 the Department of Transportation (DOT) statistics, the frequency of incidentsresulting in fatalities, injury, or significant economic loss 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 cause 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.

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. This worst case scenario would not result in a 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 of this occurring.

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-6 and 7)**.

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 would 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 hazardous 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.

The use of anhydrous ammonia can result in the formation and release of a gaseous 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 that 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 likely result in a gas jet of ammonia leaving the containment structure at a high rate. In an actual release the resultant cooling of the ammonia in the tank due to reduced pressure and auto refrigeration would have the effect of lowering the temperature of the ammonia remaining in the containment vessel, limiting the ammonia release rate. However, pursuant to EPA and CAL ARP guidelines, the worst-case off-site consequence analysis did not consider this mitigating 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 looks at four “bench mark” concentration levels: 1) the lowest concentration posing a risk of lethality, or 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 150 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. As part of its analysis of a potential release, staff evaluates the locations at which each of these benchmark concentration levels would be reached. 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 postulated release exceeds 75 PPM at any public receptor, staff presumes that the potential may exist for a significant impact. However, staff may also conduct further analysis to refine its estimates and assess the probability of occurrence of the release and/or the nature of the potentially exposed population. Staff may, based on such analysis, ultimately 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 analyses, it was assumed that spilled material would be contained in the covered basin below the storage vessel and below the tanker truck pad. In addition, the applicant assumed winds of 1.0 meter per second and atmospheric stability class F. The U.S. 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 conducted by the applicant showed that off-site airborne concentrations of ammonia would be above the level the Energy Commission uses for significance (75 ppm), but only 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 1,476 feet, an area which includes the open space (fields) to the east, south, and north of the facility, and slightly beyond 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 the modeled catastrophic release. The probability of a tank failure occurring at the same time farm workers are present, with low winds blowing in the direction of workers and F class atmospheric stability, is too low to be considered plausible. 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.

Staff conducted an independent review of the applicant's modeling of a failure of the anhydrous ammonia storage tank and found that the input variables for the SLAB modeling were generally correct for this type of accidental release. Some minor inconsistencies (differences of 1-2%) in input parameters were found when compared to those recommended by the SLAB guidance document, but when SLAB was run with the correct values, the differences in output were negligible.

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 and 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. This opinion is based on the environmental mobility, toxicity, quantities transported, and frequency of delivery of the various chemicals.

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 cloud formed during the release.

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. The Applicant prepared a transportation risk analysis on October 9, 2001 (EAEC 2001v, page 3). This analysis indicated that the risk associated with transportation of anhydrous ammonia to the EAEC would be insignificant. Staff agrees with this conclusion and the Applicant's focus on the surface streets within 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 U.S. Department of Transportation Regulations [49 C.F.R. Subpart H, §172-700], and California Department of Motor Vehicles (DMV) Regulations on Hazardous Cargo). These regulations also address the issue of driver competence.

Staff also evaluated the risk of impact associated with the transportation of anhydrous ammonia based on transport statistics developed by Davies and Lees (Lees 1996). Based on this data, the worst-case accident rate for transport by rural multi-lane undivided roads would be applicable to the project area. The maximum rate of accidental release per vehicle mile traveled on such roads is .36 in one million miles traveled (Lees 1996). The incidence of significant spillage per vehicle mile is estimated to be 1×10^{-7}(that is, one in every 10 million miles traveled) For vehicles transporting hazardous materials, about 10% of all accidents cause fatalities. Most of these fatalities occur in the immediate vicinity of the accident. Typically such fatalities are the result of injuries associated with the accident itself not accidental release of cargo. In fact, the average number of fatalities associated with release accidents is only 1% higher than the number of fatalities associated with accidents that did not result in release (Lees 1996). Most accidents involving significant release occur when the transport vehicle either leaves the road, overturns, or collides with a train. On average there were about 10 fatalities per accident, regardless of release. However, as mentioned above, most of these were the result of the accident rather than released materials. Based on differences between the number of fatalities in accidents with and without loss of cargo, staff estimated that 1% of the average fatality rate is due to released materials and the rest are due to the physical injuries that occurred in the accident. Another estimate provided in (Lees 1996) is that for every 40 fatalities associated with hazardous materials transport one is due to release of the hazardous materials cargo.

Further, the occurrence fatalities and injuries as indicated by accident statistics does not imply that such impacts were on nearby populations. In fact, the population most often impacted by ammonia transport accidents is other road users. The potential for impacts on in-route populations near highways will be highly dependent on the proximity of in route populations at the accident location and on other factors present at the time of the accident, such as wind direction and potential for atmospheric dispersion. It is staff's opinion that the risk of impact (injury or fatality) to the populations along the transportation route would be at least one order of magnitude less than the risk of release by itself. Risk of impact is the product of release probability and concurrent probability of worst case atmospheric dispersion conditions and presence of receptors in the area affected by hazardous concentrations. Staff has generally viewed risks with probabilities of less than 1 in 100,000 per year, for up to 10 potential fatalities, as insignificant. Based on the limited number of miles along the route that are in close proximity to proposed populated areas, staff believes that the potential risk per year of more that 10 fatalities associated with ammonia transportation for this project are well below 1 in 1,000,000 per year for in-route populations.

However, one concern that was not adequately addressed in the available accident statistics is the potential effect of dense fog on the accident rate. Dense fog frequently occurs in the project area and has been associated with very serious accidents. It is staff's belief that involvement of an ammonia transport vehicle in such an accident could result in loss of cargo and that transport would potentially increase risk of impact to both in-route populations and road users. Staff concludes that the risks associated with transportation of anhydrous ammonia are insignificant during normal driving conditions. However, staff believes that shipments should not occur when heavy fog is present on the delivery route. Staff therefore, has proposed Condition of Certification **HAZ- 8**. This condition restricts delivery when dense fog is present along the delivery route.

In light of the proposed development along Byron Bethany Road, staff further evaluated the relative risk of transporting aqueous ammonia and anhydrous ammonia. The use of aqueous ammonia would likely increase the number of hazardous materials tanker truck vehicle miles traveled per year by more than three-fold. Since most fatalities associated with the transportation of hazardous materials such as ammonia are the result of the vehicular accident and not loss of cargo, it can be argued that based strictly on vehicle miles travel and number of trips taken, the use of aqueous ammonia could possibly increase the risk to road users. This would only be true if all other factors remained the same and only the number of trips (not the time of day or the presence of other drivers) were changed.

Although staff concludes that the risks of impact from the transportation of anhydrous ammonia are insignificant, it should be noted that many members of the public have expressed concern regarding transportation of anhydrous ammonia near their communities. While the risk associated with transportation of anhydrous ammonia is very low and well within accepted norms, it is readily feasible to use aqueous ammonia. It is staff's conclusion that in the absence of a significant risk from the use of anhydrous ammonia at this proposed facility, staff can find no basis for recommending a requirement to use aqueous ammonia based on transport risks.

Because of concerns about future development along the anhydrous ammonia transportation route, staff asked the applicant to provide additional information about road improvements and land uses along the route. In response to staff's inquiry regarding transportation of anhydrous ammonia, the applicant prepared an additional response and analysis (EAEC 2002b). The applicant provided documentation that the transportation route will be improved during the construction of the Mountain House Community. Road improvements included increasing the width of the roads, adding left turn and merging lanes, adding raised medians, and adding lanes in both directions. Thus, the roads would be changed from the existing one-lane non-divided roads to a divided road with two lanes in each direction. Staff finds that these road improvements greatly increase the safety of traffic flow and hence would significantly reduce the risk associated with transportation of hazardous materials to the proposed facility. The applicant also clarified the hazardous materials transportation route to include two routes: I-5 to I-205 to Grant Line Road to Byron Road to Mountain Home Road to the project and I-5 to I-205 to Mountain House Parkway to Byron Road to Mountain Home Road to the project. Both of these routes would pass through the new Mountain House Community on Byron Road. The second route would also pass through the new community on Mountain House Parkway. The applicant also provided a detail of the planned land uses along the route within the proposed Mountain House Community. Land uses along the route would include commercial and some residential. Most residences would be located off the routes but within 1,000 feet.   The closest school would be located just beyond 1,000 feet from the road.

To address the issue of tanker truck safety, the Applicant stated that 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-9** to ensure that, regardless of which vendor supplies the 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 routes are allowed (Condition of Certification **HAZ-10**). This requirement will also apply to the transportation of hazardous wastes for disposal. Thus, no hazardous materials deliveries or hazardous waste transport will pass by the Mountain House School.

Seismic Issues

The possibility exists that an earthquake might 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, heightened concerns 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, containment areas, and 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.

Security Issues

This facility proposes to use anhydrous ammonia. This chemical has been identified by the U.S. EPA as a hazardous material where special site security measures must be developed and implemented to ensure that unauthorized access is prevented. The EPA published a Chemical Accident Prevention Alert regarding Site Security (EPA 2000a) and a Chemical Safety Alert (EPA 2000) concerning precautions to take to prevent theft of anhydrous ammonia. The U.S. Department of Justice published a special report on Chemical Facility Vulnerability Assessment Methodology (U.S. DOJ 2002). In order to ensure that this facility or a shipment of anhydrous ammonia is not the target of unauthorized access, staff's proposed General Condition of Certification on Construction and Operations Security Plan **COM-8** will require the project owner to prepare a Vulnerability Assessment and implement Site Security measures consistent with the above-referenced documents.

CUMULATIVE IMPACTS

Staff reviewed the potential for the operation of the East Altamont Energy Center combined with the existing Aqua Chlor facility located approximately 7 miles from the project site. Staff concludes that the distance separating these facilities precludes the risk of both facilities effecting the same population.

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. Staff did not identify a significant impact on any population and concludes that there will be no significant impact on any minority/low income population.

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 surrounding the anhydrous ammonia storage tanks equipped with a roof and a water-spray system to “knock-down” much of the anhydrous ammonia if accidentally released;

secondary containment areas surrounding other large quantity chemical tanks; and

a sloped containment pad that will drain into a sump placed beneath the tanker truck anhydrous ammonia delivering area; 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, regulations, 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; and

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 that 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 on-site 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 of the required Risk Management Plan (RMP).

To address transportation risks staff proposes requiring the use of specific routes for delivery, requiring use of high integrity vehicles, and restricting delivery during hazardous fog conditions. Staff has not recommended requiring the use of aqueous ammonia. However, its use would be feasible.

FACILITY CLOSURE

The requirements for the handling of hazardous materials would 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

San Joaquin County Board of Supervisors

Comment: *The Board of Supervisors stated its opposition to the facility unless certain environmental concerns were addressed.*

Response: Staff has evaluated the comments of the SJC Board of Supervisors and has proposed several Conditions of Certification which will mitigate hazardous materials impacts to a level of insignificant risk.

PUBLIC COMMENTS

G&DK-1 *Gary and Dolores Kuhn expressed concern about the proximity of Mountain House School to the EAEC project and the danger of transporting and storing ammonia that could potentially harm the public. They also asked if an ammonia leak would necessitate a warning and shelter at the Mountain House School.*

Response: The worst-case facility accidental release 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. No warning system or shelter would be necessary.

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

Response : The Applicant has stated that anhydrous ammonia will be delivered 37 times per year. The tank truck will have a capacity of 7,500 gallons. The two storage vessels each have a capacity of 10,000 gallons.

G&DK-17 *Mr. And Mrs. Kuhn requested an explanation to why anhydrous ammonia is used instead of aqueous ammonia.*

Response: The applicant has proposed to use anhydrous ammonia. Staff evaluated the storage, use, and transportation of anhydrous ammonia and, after mitigation, could find no significant impact. Therefore, staff could find no basis for recommending a requirement to use aqueous ammonia. The applicant claims that anhydrous ammonia is less expensive and because it is more concentrated than the aqueous form, will result is fewer tanker truck trips from the Interstate through the community.

J&DH-1 *Mr. And Mrs. Hayes asked for mandatory routing of anhydrous ammonia shipments to be on Byron Highway only and never past the school.*

Response: Proposed Condition of Certification HAZ-10 requires the Byron Highway route to be used. No hazardous material or hazardous waste will be transported past the Mountain House School.

JHS-1 *Ms. 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.*

Response: Staff has thoroughly evaluated the applicant's proposed handling, storage, and transfer methods for all hazardous materials (in particular, anhydrous ammonia) as well as the applicant's off-site consequence analysis. Staff is confident that when implemented, the Applicant's safety program will prevent accidental releases and should one occur, these measures will ensure that there are no impacts to 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).

G&MG-2 *Mr. And Mrs. Griffith also expressed concern about the potential risks posed to students at Mountain House School.*

Response: Please refer to the response above.

G&MG-3 *Mr. And Mrs. Griffith also expressed concern about the potential risks posed by ammonia and the natural gas pipeline.*

Response: 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 (the original and most recently proposed alternative routes) will be constructed, marked, and monitored as per U.S. 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.

SCOPING MEETING COMMENTS AND RESPONSES

Comment 7: *Is the plant a possible target for terrorist activity?*

Response: All private and public infrastructure are possible (but not very probable) targets for terrorist activity. Potentially catastrophic accidents (which may be similar to terrorist events) are analyzed in the Hazardous Materials Management Section. In this section, both the gas pipeline and ammonia tanks and procedures are evaluated. An emergency action plan and a fire prevention plan are required, as stated in the Worker Safety and Fire Protection Section. Staff has additionally proposed a Condition of Certification (HAZ-13) that would require the project owner to prepare a Vulnerability Assessment and implement Site Security measures consistent with US EPA and US Department of Justice guidelines.

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 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 the U.S. 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 ammonia.

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 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.

Verification: The project owner shall provide to the CPM, in the Annual Compliance Report, a list of hazardous materials contained at the facility in reportable quantities.

HAZ-2 The project owner shall concurrently provide a Business Plan (BP) and a Risk Management Plan (RMP) to the Certified Unified Program Authority - CUPA (Alameda County Environmental Management Department) and the CPM for review at the time the RMP is first submitted to the U.S. Environmental Protection Agency (EPA). The project owner shall include in the Business Plan all hazardous materials at the site and at lineal facilities and shall reflect all recommendations of the CUPA and the CPM in the final BP and RMP documents. Copies of the final Business Plan and RMP, reflecting all comments, shall be provided to the CPM.

Verification: At least 60 days prior to receiving any hazardous material on the site, the project owner shall provide a copy of a final Business Plan to the CPM. At least 60 days prior to delivery of ammonia to the site, the project owner shall provide the final EPA-approved RMP to the CUPA and the CPM.

HAZ-3 The project owner shall develop and implement a Safety Management Plan for delivery of 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 ammonia with incompatible hazardous materials.

<u>Verification:</u> At least sixty (60) days prior to the delivery of 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 ammonia storage facility shall be designed to either the ASME Pressure Vessel Code (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. The final design drawings and specifications for the ammonia storage tank and secondary containment basins shall be submitted to the CPM.

<u>Verification:</u> At least sixty (60) days prior to delivery of 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 within 100 feet of the sulfuric acid tank.

<u>Verification:</u> 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 after 30 years and every 5 years thereafter.

<u>Verification:</u> 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 full and comprehensive pipeline design reviews 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.

<u>Verification:</u> 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 a significant 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.

<u>HAZ-8</u> The project owner shall direct all vendors delivering ammonia to the site during the months of November through April to verify that fog conditions do not exist along state roads used for the delivery by calling the CALTRANS Highway Information Network prior to commencing delivery. If fog conditions exist, then delivery of anhydrous ammonia to the site shall be postponed until such time that the fog conditions have abated

Verification: At least sixty (60) days prior to receipt of ammonia 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 policy for verification of road conditions.

HAZ-9 The project owner shall direct all vendors delivering ammonia to the site to use only tanker truck transport vehicles which meet or exceed the specifications of DOT Code applicable to the type of ammonia used.

Verification: At least sixty (60) days prior to receipt of ammonia on site, the project owner shall submit copies of the notification letter to supply vendors indicating the transport vehicle specifications to the CPM for review and approval.

HAZ-10 The project owner shall direct all vendors delivering any hazardous material to, or hazardous wastes away from, the site to use only the routes approved by the CPM (Interstate 205 to Mountain House Parkway or I-205 to Grant Line Road, and then to the Byron Bethany road to Mountain House 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 area potentially affected by a turbine over-speed accident and that no combustible or flammable material is stored within 50 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.

HAZ-12 The project owner shall ensure that whenever the HRSG is cleaned with hydrochloric acid (HCl), a temporary berm shall be erected around the HCl storage vessel limiting the area of a spill to the smallest possible.

Verification: At least sixty (60) days prior to the initial receipt of HCl on-site, the project owner shall provide copies of the temporary berm design drawings to the CPM for review and approval.

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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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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

Testimony of 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 of 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).

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. 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 the ECAP area. In 2001 the ECAP was revised as a result of a local initiative, Measure D, which is summarized below.

Specific ECAP policies applicable to the EAEC project are listed below:

Policy 1 directs the County to identify and maintain an Urban Growth Boundary that defines areas suitable for urban development. A related item, Policy 17, restricts the County from approving urban development if it is located outside of the Boundary;

Policy 14A restricts the County from authorizing public facilities or other infrastructure in excess of that needed for development consistent with the agricultural land preservation goals embodied in Measure D. Infrastructure needed to create adequate service for the East County is acceptable;

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 85 (and Policy 81) restates the concept that areas designated "Large Parcel Agriculture" include agricultural processing facilities and other uses that primarily support the area's agricultural production;

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; and

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 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 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. It now requires a 100 acre minimum parcel size. 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.

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). 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 buildings 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).

Other Applicable County General Plans and 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). Approximately 1.5 miles of the recycled water line lie within the county's Agriculture-Urban Reserve designation and within the Mountain House Specific Plan (EAEC, 2002).

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.

Resolution Opposing the Proposed Construction of a Major Power Plant on the Border of San Joaquin County/Alameda County Line

Resolution R-01-406, passed and adopted June 26, 2001, by the San Joaquin County Board of Supervisors, states the Board's opposition to 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). Portions of the recycled water pipeline are located in the County's Agriculture-Urban Reserve 20 (AU-20) zone (EAEC, 2002).

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). Approximately 0.5 miles of the recycled water line runs alongside Mountain House areas zoned for General Industrial and Public Facilities (EAEC, 2002).

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 2001 and EAEC 2001r). 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 Administration (Western) Tracy substation and major transmission line corridors. Three high voltage transmission lines cross the property north of the proposed plant site. 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 thirty-four (134) 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).

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, is located 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.

Byron Airport is approximately 3 miles northwest of the site in Contra Costa County.

Construction for the new community (i.e., urban development) of Mountain House is occurring approximately 2 miles southeast of the project site in San Joaquin County. However, the boundaries for the future development will be approximately one mile east of the site.

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: irrigated agricultural land and pasturelands; the Delta-Mendota Canal water management area which 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).

PROJECT FEATURES

The EAEC would consist of an 820 MW combined cycle plant augmented by 245 MW of duct firing, and a 230 kV switchyard. These facilities would occupy approximately 25 acres.

The linear facilities for the project would include two new 0.5-mile 230-kV transmission lines in Alameda County; a 1.8-mile natural gas supply line in Alameda County; a 2.1-mile water supply line in Alameda and Contra Costa Counties; a 1.5-mile recycled water line in Alameda and San Joaquin Counties, and a buried, short fiber optic line running across Mountain House Road from the project site to the Tracy Substation (EAEC, 2002).

The raw water supply line would follow Mountain House Road and Byron Bethany Roads for short distances before following a field road and crossing under the Delta Mendota Intake Channel. All raw water supply lines proposed for the project would exist in zones designated by both Alameda and Contra Costa Counties as either agricultural or public zones.

An approximately 4.6-mile recycled water line would run northeast from the project site to Byron Bethany Road, southeast along the south side of the road crossing from Alameda to San Joaquin County, east along Bethany Road and then north on Wicklund Road, both in San Joaquin County.

A new 20-inch natural gas pipeline would be installed along an existing ROW, and would connect to PG&E's main existing pipeline. All gas pipeline alternatives would 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).

IMPACTS

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; or

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 if it precludes or unduly restricts existing or planned future uses.

CONFORMITY 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). To ensure compliance with FAA regulations regarding the marking and/or lighting of the EAEC's exhaust stacks, staff is recommending that the Commission require Condition of Certification **LAND-5.**

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 174-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:

ACCDA 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).

The Alameda County Certificate of Compliance was docketed on November 9, 2001, in Data Set 2I. Therefore, it conforms to the requirements of the Subdivision Map Act.

Alameda County Land Use LORS and policies

Alameda County ECAP and Zoning Ordinance

Energy Commission staff has reviewed the ECAP; Measure D which modifies the ECAP; and the Alameda County Zoning Ordinance. Staff has identified four policy items that we think are unclear, and may be subject to varying interpretations. 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.
>
> The power plant project may not conform to the allowable uses for the County's "A" District designation, particularly given the agriculture-oriented provisions of Measure D.

Staff generally considers electric generating facilities such as the EAEC to be large industrial uses, which depending on the overall geographic setting, can fit into the broad category of urban development. The ECAP as modified by Measure D, emphasizes the County's commitment to agricultural activities and agricultural land preservation in the region which includes the EAEC site. Measure D's redefinition of the ECAP designation of Large Parcel Agriculture requires a minimum parcel size of 100 acres. Although the EAEC parcel size is 174 acres, the EAEC is clearly a non-agricultural use which would require conversion of prime agricultural land.

While Measure D focuses primarily on limiting East County development to very low density agricultural uses, its Policy 14A does permit infrastructure necessary to provide adequate services for the area. Its redefinition of the Large Parcel Agriculture designation permits utility corridors. Staff's review of the ECAP as amended by Measure D, indicated that large power plants were not specifically addressed.

The County's Zoning Ordinance specifies that public utility uses are conditional uses which are permitted in A districts, if approved by the County's zoning administrator. Since the EAEC is a privately owned, merchant power plant that would serve a broad region of electricity consumers beyond the confines of the ECAP area, staff was uncertain about its status as a public utility use. Staff believes that the emergence of merchant plants in California has made the concept of electricity generation as a "public good or service" somewhat ambiguous. Furthermore, staff was uncertain about whether Measure D's provisions would affect the uses allowed in A Districts.

Energy Commission staff has reviewed letters dated August 15, 2001, October 4, 2001 and April 26, 2002 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, the Alameda County Zoning Ordinance, and the issue of "need" (as referenced in Measure D) in regard to the facility. The Director's August 15, 2001 letter also addressed the status of the site as a legal parcel in accordance with the State Subdivision Map Act.

Pursuant to the four local land use policy items noted above, and the first two letters from Alameda County, Energy Commission staff met with the Director of the County's Community Development Agency, Adolph Martinelli, and his staff on November 16, 2001. We discussed a number of questions 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, and allowed under the ECAP's Policy 14A.

They acknowledged that given the 1,100 MW size of the EAEC, the project will provide electricity beyond that "needed" by the East County area residents and businesses. However, they stated their belief 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. Furthermore, the EAEC would function as a public utility because it substantially serves a key need of the public at large.

Commission staff formalized the questions asked at the November 16, 2001 meeting in a March 7, 2002 letter to the Director of the County's Community Development Agency, Adolph Martinelli. Commission staff issued the letter in order to receive clarification on issues raised in the first two letters and the November meeting. The April 26, 2002 reply to the Commission's letter concurred with and formalized the answers provided at the meeting.

The Commission staff believes that there are a number of reasonable perspectives on 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 open to varying interpretations. While staff considers the EAEC to be an industrial use requiring agricultural land conversion, we believe that Alameda County's interpretation of the plant as infrastructure which is needed to meet electricity needs in the County is plausible. The County's overall conclusion that the project complies with the ECAP, including the provisions of Measure D, is also plausible. The Alameda County letters and November meeting provide Commission staff policy guidance for the project's conditions of certification and provide the County's findings regarding the consistency of the project with County LORS. While the Energy Commission is the CEQA lead agency, staff generally defers to local governments' interpretation of their land use LORS and policies.

While Commission staff has received further information from the County since the PSA in the form of the April 26, 2002 letter, staff's conclusions remain unchanged from the PSA. Although staff does not completely agree with the conclusions of the County, we find that its interpretation is a reasonable one and defer to the County's interpretation of their own laws, ordinances, standards, and policies.

To ensure that the EAEC conforms with the Alameda County Zoning Code, staff is recommending that the Commission require the following Conditions of Certification:

LAND-1 regarding compliance with the design and performance standards for the A District;

LAND-2 regarding compliance with the County's parking standards;

LAND-3 regarding compliance with the County's oudoor advertising regulations applicable to any EAEC signs erected (either temporary or permanent);

LAND-4 regarding the County's review and comment on descriptions of the final laydown/staging areas identified for construction of the EAEC; and

LAND-6 regarding compliance with the County's requirements for minimum setbacks from the property line.

Alameda County Agricultural Land Preservation Activities

Alameda County is in the process of forming an agricultural land trust, which is an impact mitigation response to the farmland and open space conversion associated with the EAEC project, and part of its overall effort to implement ECAP Policies 76 and 77 and Measure D. On August 28, 2002, the Alameda County Board of Supervisors adopted an Amended and Restated East Altamont Energy Center Mitigation Agreement which was signed by a representative from the Alameda County Counsel's Office, and a representative of the applicant. The amended and restated provisions in the agreement reflect the County's acceptance of the Commission staff's suggestions to strengthen the linkage between the use of funds for farmland preservation and mitigation of impacts.

Conditional Use Permit Findings Required for Public Utility Uses in "A" Districts

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. 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 below under provisions of its Zoning Ordinance. Mr. Sorenson agreed to the Energy Commission staff's request that the County staff make these findings, which were received in a letter from the Director of the County's Community Development Agency, Adolph Martinelli, dated December 17, 2001. In this letter, the Director provided a list of findings that the County would be required to make for the project if it were the authorizing agency to bring it into conformity with Alameda County LORS. The conditional use permit findings from the December 17, 2001 letter are presented as follows:

1. Is the use required by the public need?

   Yes. The State of California experiences episodes when the grid, or system of power generating facilities, transmission lines and substations that provide electrical energy to California, is unable to either generate or transmit enough energy to all users to allow uninterrupted supply to homes, commercial and industrial uses, and essential public services. The State of California imports a considerable percentage of the electricity consumed because there is inadequate generating capacity within the state. Rolling blackouts are implemented by the California Independent System Operator to fairly apportion the limited energy. Alameda County utilizes the same grid network as the rest of the State, and is subject to these periodic shortages of electrical energy. The proposed power plant would provide a significant contribution to the State and County electrical energy supply and reduce the potential for interruption of electrical service during periods of high consumption. In addition, generation from cleaner, modern facilities helps displace generation from older more polluting plants, thereby reducing air emissions (ACCDA, 2001c).

2. Will the use be properly related to other land uses and transportation and service facilities in the vicinity?

   Yes. Although the proposed use is not agricultural in nature, the applicant has agreed to help preserve and enhance agricultural use within Alameda County, both locally on the same property, and in other areas through the use of grants to County for agricultural preservation. The use will not inhibit agricultural use on adjacent parcels of land, it will not significantly affect the immediate human environment if proposed mitigation measures are adopted and implemented, and the low volume of trips generated by the proposed power plant is fully compatible with the adjacent rural transportation system. The location of the proposed plant is considered appropriate due to the close proximity of available water, natural gas supply lines and electrical lines, all of which are essential for the production of electricity. The proposed project is compatible with other public, utility, and industrial uses nearby including the Tracy substation, pumping plants for the Delta-Mendota Canal and the California Aqueduct, the PG&E gas compressor station and several wind turbine projects. All required services are being provided (ACCDA, 2001c).

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?

No. The mitigation, monitoring and reporting elements described in the Application for Certification by this project, further described in the Preliminary Staff Assessment in the sections on Public Health, Hazardous Materials, Worker Safety, Transmission Line Safety and Nuisance, and Waste Management for this project, and agreed to by the applicant, will ensure that the use will not be detrimental to any of the surrounding properties or the health, safety or welfare of the general public (ACCDA, 2001c).

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?

   No. Public and quasi-public uses, which include public utilities and private entities that provide services such as natural gas, electricity, and water and that serve an important public need, are conditionally permitted in the A – Agriculture District, and with appropriate conditions of approval and design considerations are consistent with applicable policies of the Alameda County General Plan including the East County Area Plan (1994) as amended by Alameda County Measure D (November 2000) (ACCDA, 2001c).

Commission staff believe that the conditional use permit findings presented by the County are not unreasonable, and that the proposed EAEC is consistent with the findings and could be permitted as a conditional use.

<u>Other Local Land Use LORS and policies</u>

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. Similarly, the linear facilities extending from the proposed project into San Joaquin County are consistent with the land use designation and zoning for the lands they traverse.

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.
Western operates the Tracy substation and the adjacent transmission corridor, 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; and 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 prime agricultural land, the applicant, in coordination with Alameda County, has proposed to mitigate by contributing funds to Alameda County for a 1:1 purchase of prime agricultural land for permanent farming use and/or easement purchases; and establishment of a local agricultural land trust.

Staff supports the above mitigation approach in principle, but recommends **Condition of Certification LAND-7** to ensure that the potentially significant impact caused by the conversion of agricultural land will be fully mitigated**.** The applicant has signed the Amended and Restated East Altamont Energy Center Farmlands Mitigation Agreement, which is a joint document also signed by Alameda County. Per the Agreement, the applicant is committed to providing a total of one million dollars to the County for the purchase of 40 acres of prime farmland that would be in permanent agricultural use, through establishment of a preserve or purchase of easements. Staff believes that when the County has received the initial and final payments, the potentially significant impact will have been sufficiently mitigated. **LAND-7** provides a written, formal link between the Commission's decision on the EAEC project and the Agreement.

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 temporarily 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 EAEC's linear facilities. 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), would be affected by air quality impacts and the visual impacts of the plume from the proposed facility. As travelers on 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.

Without mitigation in the form of agricultural land preservation and land trusts, the project presents a potentially significant impact due to the conversion of agricultural resources and open space. Staff believes that with the implementation of **Condition of Certification LAND-7,** the EAEC is compatible with existing and planned land uses in the East Altamont area, and impacts would be less than significant.

CUMULATIVE IMPACTS

Land Use Table 1 displays the cumulative projects within a 6-mile radius of the project site.

Land Use Table 1
Cumulative Development Projects

Development	Size	Location	Jurisdiction	Status
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 Service District – "New Town" Development	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. The project involves development of a new community with residential, commercial, and industrial development
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 southeast, 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.
North Livermore Plan	13,500 acres	Approx. 7.5 miles to the southwest, north of Livermore	City of Livermore	EIR was finalized and adopted by the City of Livermore in 2000. The plan has been delayed due to passage of Alameda County Measure D.
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; environmental permitting process is in progress. Groundbreaking 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	Approved by CEC; construction 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.

Source: TPP, 2001; San Joaquin County, 2000; San Joaquin County, 2001; EAEC, 2001; FPL Tesla, 2001; HDR, 2001; Lombardo, 2001; Stentz, 2002.

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. Staff believes that the EAEC Farmlands Mitigation Agreement between the applicant and the County of Alameda, along with **Condition of Certification LAND-7**, will 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 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 land use analysis, staff has not identified significant unmitigated 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

EAST BAY REGIONAL PARK DISTRICT

Comment: *In a letter Dated January 14, 2002, the East Bay Regional Park District (District) stated that the District is considering development of a number of trails in the Livermore and Tri-Valley area, including the area around the Mountain House development, Bethany Reservoir, and the Brushy Peak Regional Reserve. The District was concerned that development of the EAEC project take the prospect of future trails into account, when addressing roadway improvements and various design components.*

Response: Staff discussed the letter with District staff on June 14, 2002. The District is primarily concerned with preserving trail options in the Bethany Reservoir area, which is approximately 2.5 miles from the EAEC site. Currently, there are no trail plans in the vicinity of the EAEC project, so EAEC roadway improvements and other design features will not affect trail opportunities.

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 FSA section "Alameda County Land Use LORS and policies". Staff has addressed the item regarding the conversion and loss of productive agricultural land in the FSA 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 acres 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 FSA section "Alameda County Land Use LORS and policies."

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. Although staff does not completely agree with the conclusions of the County, we find that its interpretation is a reasonable one and defer to the County's interpretation of their own guidelines, standards, policies and conclusions that the EAEC is a consistent and allowed use.
2. Staff supports the County's successful effort to reach a mitigation agreement with the applicant regarding the conversion and loss of productive agricultural land, which is a potentially significant impact. After reviewing the final agreement, Staff has concluded that in order to reduce the potentially significant impact to a level of insignificance under CEQA, the applicant must comply with **Condition of Certification LAND-7** in addition to contributing the agreed upon $1 million fee in the Farmland Mitigation Agreement.
3. 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.
4. 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.
5. 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.

   If the project is certified, staff recommends that the Commission adopt the following proposed Conditions of Certification.

PROPOSED CONDITIONS OF CERTIFICATION

LAND-1 The project owner shall comply with the minimum design and performance standards for the "A" District set forth in the Alameda County Zoning Ordinance.

Verification: At least 30 days prior to the start of construction, the project owner shall submit written documentation, including evidence of review by the Alameda County Community Development Agency that the project meets the above referenced requirements and has been reviewed by the County.

LAND-2 The project owner shall comply with the parking standards established by the Alameda County Zoning Ordinance (Title 17, Chapter 52, Sections 780-950).

Verification: At least 30 days prior to start of construction, the project owner shall submit to the CPM, written documentation, including evidence of review by Alameda County, that the project conforms to all applicable parking standards.

LAND-3 The project owner shall ensure that any signs erected (either permanent or for construction only) comply with the outdoor advertising regulations established by the Alameda County Zoning Ordinance (Title 17, Chapter 52, Section 510).

Verification: At least 30 days prior to start of construction, the project owner shall submit to the CPM, written documentation, including evidence of review by Alameda County, that all erected signs will conform to the zoning ordinance.

LAND-4 The project owner shall provide the Director of the Alameda County Community Development Agency for review and comment and the CPM for review and approval, descriptions of the final lay down/staging areas identified for construction of the project. The description shall include:

(a) Assessor's Parcel numbers;

(b) addresses;

(c) land use designations;

(d) zoning;

(e) site plan showing dimensions;

(f) owner's name and address (if leased); and,

(g) duration of lease (if leased); and, if a discretionary permit was required; (2) copies of all discretionary and/or administrative permits necessary for site use as lay down/staging areas.

Verification: The project owner shall provide the specified documents at least 30 days prior to the start of any ground disturbance activities.

LAND-5 The project owner shall provide appropriate evidence of compliance with Federal Aviation Administration (FAA) regulations regarding the marking and/or lighting of the project's new exhaust stacks. The project owner shall provide to the CPM copies of all completed documents demonstrating FAA compliance in accordance with the schedule set forth in FAA Form 7640-2, Notice of Actual Construction or Alteration or other appropriate documentation as required by FAA. This requirement shall also be applied if at any time the project is abandoned.

Verification: At least 30 days prior to start of commercial operation, the project owner shall submit proof that the project's stacks have been marked and/or lighted in accordance with FAA regulations and requirements.

LAND-6 The project owner shall provide to the CPM for approval, a site plan with dimensions showing the locations of the proposed buildings and structures in compliance with the minimum yard area requirements (setbacks) from the property line as stipulated in the Alameda County Zoning Ordinance.

Verification: Thirty (30) days prior to the start of construction, the project owner shall submit a site plan showing that the project conforms to all applicable yard area requirements as set forth in the City/County Zoning Ordinance.

LAND-7 The project owner shall mitigate at a one to one ratio for the conversion of prime farmland as classified by the California Department of Conservation, to a non-agricultural use, for the construction of the power generation facility.

Verification: The project owner will provide payment to the Alameda County agricultural land trust of the $500,000 first installment of a mitigation fee within 30 days following the construction start, and the $500,000 second and final installment within 30 days of the commencement of commercial operation, as set forth in the East Altamont Energy Center Farmlands Mitigation Agreement.

The project owner shall provide in its monthly compliance reports a discussion of any land and/or easements purchased in the preceding month by the trust with the mitigation fee money provided, and the provisions to guarantee that the land managed by the trust will be farmed in perpetuity. This discussion must include the schedule for purchasing forty (40) acres of prime farmland and/or easements within 5 years of start of construction as compensation for the forty acres of prime farmland to be converted by the EAEC.

The project owner shall provide confirmation to the CPM that the first and final mitigation payments have been made to the Alameda County agricultural land trust.

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NOISE AND VIBRATION

Testimony of Jim Buntin and Steve Baker

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), and to ensure that noise impacts are less than significant. For an explanation of technical terms employed in this testimony, please refer to **Noise: Appendix A** immediately following this section.

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 the effects 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.

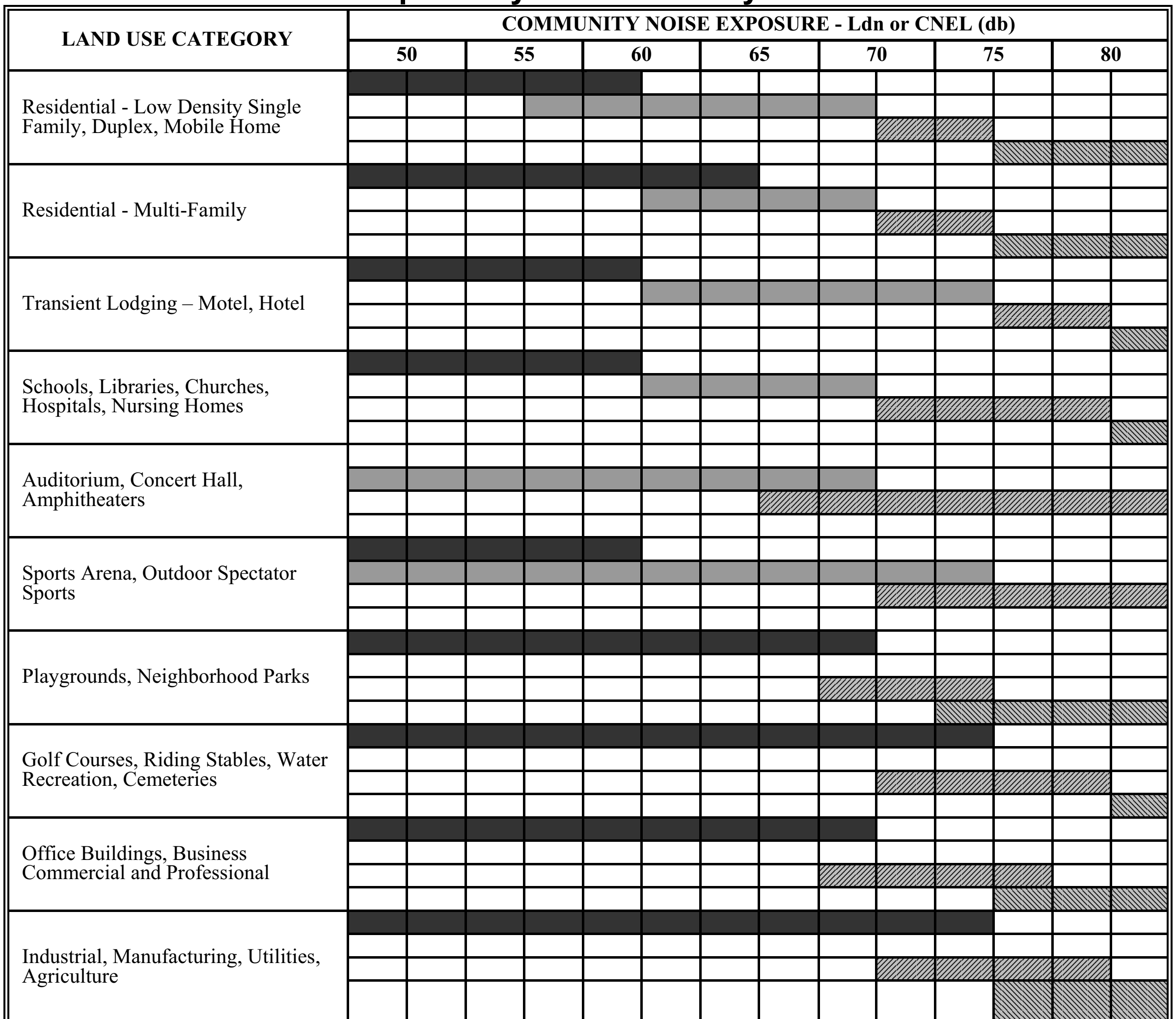
STATE

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**.

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.

Noise: Table 1
Land Use Compatibility for Community Noise Environment



(solid dark)	**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.
(gray)	**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.
(fine hatch)	**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.
(coarse hatch)	**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.

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 sensitive receptor.

Staff considers it reasonable to assume that an increase in background noise levels up to 5 dBA in a rural setting is insignificant; an increase of more than 10 dBA is clearly significant. An increase between 5 and 10 dBA should be considered adverse, but may be either significant or insignificant, depending on the particular circumstances of a case.

Factors to be considered in determining the significance of an adverse impact as defined above include:

1. the resulting noise level[1];
2. the duration and frequency of the noise;
3. the number of people affected;
4. the land use designation of the affected receptor sites;
5. public concern; and
6. prior CEQA determinations by other agencies specific to the project.

Noise due to construction activities is usually considered to be insignificant in terms of CEQA compliance if:

7. the construction activity is temporary;
8. use of heavy equipment and noisy activities is limited to daytime hours; and
9. all industry-standard noise abatement measures are implemented for noise-producing equipment.

[1] For example, a noise level of 40 dBA would be considered quiet in many locations. A noise limit of 40 dBA would be consistent with the recommendations of the California Model Community Noise Control Ordinance for rural environments, and with the data supporting the noise guidelines of the World Health Organization. If the project would create an increase in ambient noise no greater than 10 dBA at nearby sensitive receptors, and the resulting noise level would be 40 dBA or less, the project noise level would likely be insignificant.

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 standards for stationary sources in Title 6, Chapter 6.60 of the General Ordinance Code. The noise levels considered acceptable for any single- or multi-family residential, school, hospital, church, public library or commercial properties 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 County 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 two new 0.5 mile-long 230 kV transmission lines.

The equipment that has the greatest potential to generate significant noise levels includes the gas turbines, steam turbine 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, if employed, would have 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. The Mountain House residential area, currently under development, is significantly farther away from the proposed project than the above receptors.

Linear Facilities

The EAEC will connect with the electrical grid at a new switchyard located on the plant site. Approximately 0.5 miles of two new double-circuit 230 kV transmission lines will connect the new switchyard to an existing 230 kV double-circuit transmission line that will be sectionalized to provide interconnections with Western's Tracy Substation and Westley Substation. The new lines will be installed over agricultural land and Kelso and Mountain House Roads.

The project will include construction of approximately 1.8 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 existing 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 (The applicant stated in the AFC that this location is also representative of the nearby school site.)
4. A location adjacent to residences at Livermore Yacht Club

Noise: Table 3 summarizes the ambient noise measurement results at the above-listed monitoring locations (EAEC 2001, AFC § 8.5.2.2, EAEC 2001b).

NOISE Table 3
Summary of Measured Noise Levels

Measurement Sites	Measured Noise Levels, dBA			
	Average During Daytime Hours	Average During Quietest Nighttime Hours		CNEL
	L_{eq}	L_{eq}	L_{90}	
1 (January 2001)	55.0	45.9	31	57
1 (October 2001)	47.8	42.1	34	59*
2 (January 2001)	52.3	44.6	30	57
2 (October 2001)	51.5	48.6	39	56*
3**	66	39.4	30 - 32	55 - 60*
4 **	58	38.4	32 - 33	55 – 60*

* - Energy Commission staff calculation or estimate
* * - Derived from 10-minute samples

The noise environment in the immediate vicinity of the project site is dominated by noise from the wind, distant traffic, and agricultural activities.

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 per 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 applicant provided data (EAEC 2001b) indicating that the high-speed wind pattern occurs during daytime 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 (L_{90}) in October were significantly 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, when there is less wind, ambient noise levels are expected to be quite low. However, because people are more likely to be indoors with their windows closed, staff views winter noise levels as less critical than summer noise levels. Because residents are likely to open windows during the summer months, the summertime noise levels are used for judging potential noise impacts.

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 to 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 daytime ambient 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 substantially exceed the range of daytime 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 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 loudest noise encountered during construction, inherent in building any project incorporating a steam turbine, is created by the steam blows. After erection and assembly of the feed water and steam systems, the piping and tubing that comprises the steam path has accumulated dirt, rust, scale and construction debris such as weld spatter, dropped welding rods and the like. If the plant were started up without thoroughly cleaning out these systems, all this debris would find its way into the steam turbine, quickly destroying the machine.

In order to prevent this, before the steam system is connected to the turbine, the steam line is temporarily routed to the atmosphere. Traditionally, high pressure steam was 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, was quite effective at cleaning out the steam system. A series of short steam blows, lasting two or three minutes each, was performed several times daily over a period of two or three weeks. At the end of this procedure, the steam line was connected to the steam turbine, which was then ready for operation.

These high-pressure steam blows could produce noise as loud as 130 dBA at a distance of 100 feet. In order to reduce disturbance from steam blows, the steam blow piping could be equipped with a silencer that would reduce noise levels by 20 to 30 dBA, still an annoying noise level.

In recent years, a new, quieter steam blow process, variously referred to as QuietBlow™ or Silentsteam™, has become popular. This method utilizes lower pressure steam over a continuous period of 36 hours or so. Resulting noise levels reach only about 80 dBA at 100 feet; noise levels at nearby receptors are typically similar to the ambient background noise level, and thus barely noticeable. Even more recently, compressed air has been substituted for steam in the continuous blow process; resulting noise levels are similar.

According to the applicant, un-silenced high-pressure steam blow noise levels could be as high as 95 dBA at the nearest receiver (Site 1). 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 2001a). Steam blow noise levels at the nearby school would be slightly lower than these values, as the school is about one-half mile farther away. The resulting noise levels would be in the range of ambient noise levels during daytime hours and thus would not result in a significant impact. The applicant has proposed to mitigate the noise generated from construction steam blows by use of a silencer similar to that described above.

In order to minimize annoyance due to steam or air blows, staff proposes Conditions of Certification to limit noise from steam blows by requiring the use of a temporary silencer to achieve the noise level cited above, and to implement a notification process to make neighbors aware of impending steam blows (see proposed Conditions of Certification **NOISE-4** and **NOISE-5** below). This should ensure that the noise from steam blows is within reasonable limits at the nearest residences.

Linear Facilities

New off-site linear facilities will include gas and water lines, and 230 kV transmission lines. 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 as required by **NOISE-8**, the noise due to horizontal drilling will be less than 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 some industry-standard 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, however, 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 would represent an essentially 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, circulating 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. 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 in the AFC included:

- enclosing combustion turbines to meet 85 dBA at 3 feet
- enclosing the steam turbine generator
- silencers on relief valve stacks
- designing major components to limit noise to 90 dBA or 85 dBA at 3 feet
- locating the power block in central portion of site
- locating cooling towers on north side of site
- locating brine concentrator compressor inside waste water treatment facility

Noise: Table 5 lists the predicted project noise levels at the nearest receptors in terms of the background noise level (L_{90}). The October noise level measurement data were used to represent summer conditions. The predicted noise levels take into account the applicant's proposed standard noise abatement design measures listed above (EAEC 2002a).

Noise: Table 5
Summary of Predicted Operational Noise Levels

Receptor Sites	Nighttime L_{90}, dBA			
	Summer Ambient	Project	Cumulative	Change
1	34	45	45	+11
2	39	42	44	+5
3	30 – 32	43	43	+11 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 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. Therefore, the proposed project would result in a significant noise impact at the nearest residential land uses.

At Site 3, the plant noise level is predicted to be 43 dBA. It can be extrapolated from this that the plant noise level will be lower than 43 dBA at the school site, which is located south of Site 3. 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.

CEQA requires that noise impacts from a project be mitigated to a level of insignificance. In determining if a significant impact will likely occur, Energy Commission staff has traditionally followed the noise industry custom of assuming that a project that increases the existing noise level at a sensitive receptor by 5 dBA or more holds the potential to produce a significant adverse impact, and that further study is warranted in such situations. (A change of five dBA is considered to represent an increase in noise that is noticeable, but not necessarily annoying, to a majority of receptors.) See **Noise: Appendix A** for additional descriptions of the effects of noise on people.

A power plant operates as essentially a steady, continuous noise source, unlike the relatively random intermittent sounds that normally comprise a noise environment. As such, power plant noise contributes to, and becomes part of, the background noise level, or the sound heard when most intermittent noises cease. When no traffic is driving by, no airplanes are flying overhead, no dogs are barking, no frogs are croaking, and no strong wind is blowing, what remains is background noise. This "background noise level" is commonly described by the L_{90} value, which is the noise level exceeded 90 percent of the time. In most cases, a power plant will operate around the clock, for most of the year. The plant will thus contribute to, and often define, the background noise level.

Nighttime ambient noise levels in rural areas are typically lower than the daytime levels; differences between day and night background noise levels of 5 to 10 dBA are common. Exceptions may occur when insects and frogs are active at night, and when winds blow far into the night. With this assumption, staff usually believes it both prudent and conservative to employ the lowest nighttime background noise level values as the relevant noise regime. To reflect the fact that noise levels vary naturally over the quietest periods, staff does not assume that a single hourly background noise level should be used as the standard of potential impact. Rather, it is usual to calculate the average L_{90} value for the quietest period of the night, typically a period of four hours or more.

Staff also considers the potential for annoyance by plant noise at night when residents are trying to sleep. It is common in rural areas (as in this case) to find that ambient noise levels are lower in winter months than in summer months. In summer, however, residents are more likely to sleep with windows open, exposing them to higher plant noise levels inside the house than in the winter months, when windows are typically closed. Thus there is a higher potential for plant noise to annoy people during the summer months.

In this case, ambient background noise levels during nighttime hours range from 27 dBA to 48 dBA, with the lowest noise levels attained during winter. The projected cumulative power plant noise levels, after including the proposed standard noise control measures listed above, are in the range of 38 dBA to 45 dBA, as cited in **Noise: Table 5**. If constructed as proposed, the project's noise level at the nearest sensitive receptors would represent an increase of up to 13 dBA over the nighttime ambient background noise levels. Such increases in background noise levels would be clearly noticeable, profoundly altering the noise regime in the project vicinity. Energy Commission staff considers such an increase in background noise level to be clearly significant.

The proposed Condition of Certification **NOISE-6** would require that the noise level produced by the plant operation not exceed 39 dBA L_{eq} at any residence. This would ensure that the cumulative nighttime background noise level (L_{90}) at any residential receptor would not increase by more than 8 dBA under summer weather conditions, and that noise due to the plant operations would not exceed the standards of the Alameda County Community Noise Ordinance (45 dBA nighttime) at any sensitive receptor. The resulting change in ambient noise levels of 8 dBA would be noticeable, but not necessarily annoying in and of itself. Based upon the applicant's noise level predictions, power plant noise levels would be lower than 39 dBA at all other receivers due to their greater distances from the project site.

Specifically, implementation of the proposed Condition of Certification **NOISE-6** would result in the noise levels shown in **Noise: Table 6**.

The applicant has reportedly obtained an option on the property described as the Franco residence, which is the residence nearest the project site (Site 1). Upon exercise of this option after licensing of the project, the residential structure would be removed from residential use for the life of the project. If the owner were to sell the parcel of land, the former residence would be demolished. **Noise: Table 6** was prepared with the assumption that the residence at Site 1 would no longer be used as a residence, and that the most-affected residence would be at Site 2. If the applicant were to fail to remove the residence at Site 1 from residential use, it would be necessary to achieve the noise standard at Site 1, and the predicted plant noise levels at Sites 2, 3 and 4 would be further reduced by about 1 dBA. Proposed Condition of Certification **NOISE-9** requires that the Franco residence be removed from residential use for the life of the project.

Noise: Table 6
Conditioned Plant Operational Noise Levels and Resulting Ambient Noise Levels

Site	Noise Level, dBA			
	4-Hour Background Noise Level	Permitted Plant Noise Level	Cumulative	Resulting Increase in Ambient Noise Levels
2	39	38*	42	+3
3	32	39	40	+8
4	33	34*	36	+3

* Adjusted for distance, based on applicant's unmitigated noise level predictions.

Energy Commission staff believes that achieving an operational noise limit of 39 dBA (and a cumulative noise level of 40 dBA) at any residence as required by **NOISE-6** will ensure that noise impacts will be less than significant.[2] Staff recognizes that the resulting cumulative noise levels would be considered quiet, and notes that the proposed noise limit is intended to ensure that the noise from the power plant would not

[2] When measuring an ambient noise level, noise descriptors such as L_{eq}, L_{50} and L_{90} are all useful measures. When measuring the noise from a specific source such as a power plant., L_{eq} is the appropriate measure. Combining the ambient background (L_{90}) noise level with project noise (L_{eq}) yields a noise level that can be expressed in terms of L_{eq} or, since the power plant's noise output is so constant, in terms of L_{90}, the new (cumulative) background level.

constitute an annoyance to a reasonable person accustomed to the pre-project noise environment. Application of an operational noise limit of 39 dBA is consistent with the recommendations of the California Model Community Noise Control Ordinance for rural environments, and the resulting cumulative noise levels are consistent with industrial noise standards commonly applied in European countries (Gottlob, 1995).

Other factors that were considered in reaching this conclusion were:

1. No unusual noise duration or frequency characteristics are predicted for the project.
2. There will be a relatively small number of people affected by plant noise.
3. The affected land use designations are agricultural.
4. There have been no specific concerns about the predicted plant noise levels expressed by the public or other government agencies.
5. There have been no contradictory prior CEQA determinations by other agencies specific to this project.

Staff's proposed project noise limit of 39 dBA at the nearest residence is 6 dB more stringent than the limit proposed by the applicant. 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). Later, at the PSA workshop, the applicant indicated that a plant noise level of 43 to 44 dBA might be attainable.

However, the applicant provided no technical or feasibility data to support a determination that a lower level could not be attained. Staff believes, on the basis of Energy Commission experience with other power plants, that significant additional noise reduction can be achieved using a variety of measures, such as those listed below:

- low-noise equipment such as pumps and electrical transformers
- quieter gas turbine inlet air mufflers
- noise attenuating vents on turbine generator enclosures
- noise lagging on the HRSG transition ducts
- low noise cooling fans for the cooling tower that incorporate additional fan blades or specially-designed "super low noise" fans combined with noise-reducing motor enclosures

The applicant has not stated whether such measures have been considered in the plant acoustical design, nor whether they are considered to be feasible. Staff notes that the above design features have been deemed technologically feasible for other power plant installations.

Data provided to staff for similar recent projects before the Energy Commission have shown that a noise level reduction of 8 to 10 dBA may be obtained by specifying acoustical cladding and barriers for steam turbine generators, and by specifying moderate improvements in exhaust silencers for HRSG units. Noise level reductions of up to 20 dBA have been reported for cooling towers by using super-low noise fans.

In response to staff data requests, the applicant reiterated that the project would include the standard noise control specifications listed earlier in this section. The applicant also stated that: “the most practical means of mitigating the above sources further and reducing overall plant noise levels at the receptors would be to employ external sound barriers or acoustically treated buildings.” The applicant further stated that: “Such structures are normally very costly, significantly hinder maintenance activities, and can be very large, potentially impacting other project areas.” These statements imply that further noise reduction would be impractical or too costly. Staff respectfully disagrees with this implication, noting that other power plant projects approved by the Energy Commission have incorporated practical and feasible noise mitigation measures, such as those listed above, which have resulted in lower noise levels than predicted for this project.

The applicant replied to staff’s question concerning options in noise control for specific sources with a review of the noise level reduction possibilities (and costs) for cooling fans. Unfortunately, that analysis was flawed in the initial premise that cooling fans were a dominant noise source. Furthermore, the applicant’s finding that the use of low noise cooling fans would yield only a 2.6 dBA reduction in source noise levels is inconsistent with data provided to staff concerning the Morro Bay power plant project, where low-noise fans reduced cooling tower noise by up to 20 dBA.

The remainder of the applicant’s analysis, dealing with the net noise reduction for the power plant and the costs and efficiencies associated with the change of equipment specifications, is of the type that staff would expect the applicant to perform for the noise sources that most affect the sensitive receptors.

Alternative Noise Criteria

To illustrate the effects of the proposed noise limits, and to respond to the applicant’s concern about the suitability of the L_{90} descriptor as a means of defining the threshold of potential significance, Energy Commission staff conducted additional ambient noise measurements at the home adjacent to the Mountain House School (Site 3). The measurements included hourly noise levels for two 24-hour periods, as well as one-second time histories for the hours of midnight to 6 a.m. on February 15, 2002. Representative data from this sample are shown by **Noise: Figure 2**. The ambient noise levels measured at this site were consistent with the “summer” ambient noise level data in **Noise: Table 3**, which were used to develop the noise limits proposed (**NOISE-6**) for this project.

Noise: Figure 2 illustrates the relationships between the actual noise levels measured during a typical quiet hour and the noise descriptors commonly used in environmental noise assessments (e.g., L_{eq}, L_{50} and L_{90}). In this example, the noise levels measured over each one-second period in the hour from 1:00 a.m. to 2:00 a.m. are shown; the levels vary in relation to the noise sources present in that environment. The figure shows the calculated average noise level (L_{eq}), median noise level (L_{50}), and background noise level (L_{90}) for that hour, as well as the Alameda County noise standard of 45 dBA, which is the limit proposed by the applicant.

During the hour described by **Noise: Figure 2**, the background noise level (L_{90}) was calculated to be 34 dBA. An increase of 5 dBA due to introduction of a power plant noise source would yield a continuous background noise level of 39 dBA. It can be seen from **Noise: Figure 2** that the resulting noise level would be nearly equivalent to the ambient L_{eq} value, calculated to be 39.7 dBA in this example.

In this example, if the noise limit applied to the project were 39 dBA, the plant noise level would cover most background noise sources (such as distant traffic, wind, and animals), but would not completely mask them.

If the project were allowed to increase the noise level to 45 dBA at this location, as proposed by the applicant, the plant noise level would completely mask most background noise sources. Thus the change in background noise levels would be substantial, and clearly significant.

The applicant, in a Scheduling workshop, commented that land use compatibility is often judged by compliance with a noise limit in terms of the L_{dn} descriptor, and that L_{dn} should be used as the basis of a criterion for this project. Staff notes that the issue in this case is not land use compatibility *per se*, but whether the project will result in a significant noise impact due to changes in ambient noise levels. Although it is staff's opinion that use of the L_{dn} descriptor is inappropriate and unnecessary, the following discussion illustrates the possible results of using an L_{dn}-based criterion for this project.

L_{dn} is a cumulative metric, averaging the noise exposure over the entire 24-hour day after applying a 10-dBA penalty to nighttime noise levels. The L_{dn} descriptor was originally developed by the U.S. Environmental Protection Agency (EPA) to address the potential effects of noise on public health and welfare. It has traditionally been applied to assessment of noise due to transportation sources, such as aircraft (at airports), railroad line operations, and highway traffic. The purpose of the 10-dBA nighttime penalty is to account for the potential interference of noise with sleep during nighttime hours.

In this case, the power plant noise is expected to affect nighttime noise exposures, so including daytime noise exposures in the calculations is an unnecessary complication. Since the L_{dn} metric averages noise levels over the day and night hours, it is not ideally suited to assessing noise effects during nighttime only.

In addition, the established L_{dn} criteria for land use compatibility were not intended to address the issue of changes in ambient noise levels. Instead, they were developed to address annoyance.

In 1992, the Federal Interagency Committee on Noise (FICON) recommended that annoyance be used as a summary measure of the general adverse reaction of people to noise. FICON further recommended that L_{dn} values be related to the percentage of persons "highly annoyed," using a standard equation called the "Schultz Curve."

FICON recommended a land use compatibility criterion for airports of 65 dB L_{dn}. This level would result in about 13% of the population being "highly annoyed." ("Highly annoyed" means that a person is concerned enough to identify noise as a negative factor in his or her personal environment.)

The U.S. EPA determined in 1974 that the "level of environmental noise requisite to protect the public health with an adequate margin of safety" (primarily from the standpoints of hearing protection and activity interference) is 55 dB L_{dn}. This level would result in about 4% of the population being "highly annoyed."

For a continuous noise source, the L_{dn} will be approximately 6 dB higher than the average hourly noise level (L_{eq}). The EPA-recommended level of 55 dB L_{dn} is equivalent to a continuous noise level of 49 dBA. In this case, that L_{eq} value would be about 15 dBA above the ambient background noise levels in the quietest hours of the night. This would clearly be a significant change.

Given that the L_{dn} descriptor was not intended to address noise effects limited to certain hours, and that it was not intended to address changes in ambient noise levels, staff does not believe that noise limits in terms of the L_{dn} are appropriate for power plants.

Applicant's Proposed Mitigation

The applicant has reportedly obtained an option on the property described as the Franco residence, which is the residence nearest the project site (Site 1). Upon exercise of this option after licensing of the project, the residential structure would be removed from residential use for the life of the project. If the owner were to sell the parcel of land, the former residence would be demolished.

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 would include replacement of existing windows with dual-pane windows, replacement of hollow-core exterior doors with solid-core doors, air conditioning, and additional insulation in walls. These treatments could be expected to reduce interior noise levels by about 5 dBA. The applicant has transmitted the sound attenuation offers to the three nearest residents (excepting the Franco family), but has provided no indication to date that the residents are willing to accept the proposed measures.

Staff's concerns about applying such mitigation without first applying all feasible mitigation to the noise source (the power plant) are that: 1. implementation of the additional sound attenuation would not mitigate exterior noise levels, but would only serve as an enhancement of the acoustical environment inside the homes; and 2. there is no certainty that all affected residents will ultimately accept, and be satisfied with, the offered mitigation. Were that not to occur, then the mitigation upon which the Commission's decision was based would not occur. Note that staff believes that retrofitting the power plant itself after construction, to reduce noise impacts, may not be feasible. Retrofitting the sort of noise mitigation features suggested above by staff would be much more costly than incorporating them in the initial design of the project.

On September 3, 2002, the applicant docketed a revised response to staff's Data Request 78 (EAEC 2002ppp). In brief, the revised response:

1. misinterprets staff's proposed Condition of Certification **NOISE-6**, which allows a project noise level of 39 dBA, combined with the ambient background noise level of 32 dBA (at monitoring site 3), to produce a cumulative level of 40 dBA. The applicant claims that the project alone should be allowed to produce 40 dBA at site 3;
2. shows, without explanation, in Table 78-1 ambient background (L_{90}) noise levels at monitoring sites 3 and 4 that are from three to six dBA greater than previously measured; and
3. estimates the capital and operating costs of applying noise mitigation to the project. Staff notes that the applicant still does not claim that adding such mitigation measures would be infeasible or cause them to abandon the project.

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.

LORS COMPLIANCE

Alameda County has registered disagreement with staff's interpretation of the Alameda County Noise Ordinance. This Ordinance states that "It is unlawful to create any noise which causes the exterior noise level when measured to exceed the noise standards "These standards, for residential and school properties, are 50 dBA L_{50} during the daytime and 45 dBA L_{50} during the nighttime.

The Directors of the County Development Agency and Environmental Health Services Department disagreed with staff's interpretation. Their letter of December 17, 2001, stated that the noise standard of the Noise Ordinance "does not specify a standard for ambient cumulative noise levels but only for source-specific noise."

Staff respectfully disagrees. The language of the Ordinance, quoted above, refers to the total, or cumulative, noise due to the project superimposed on the ambient noise level: "…any noise which causes the exterior noise level to exceed the noise standards." The project noise, added to the existing (ambient) noise level, could cause the (cumulative) exterior noise level to exceed the standards.

While these two positions vary, this disagreement should have no impact on the project's compliance with the Alameda County Noise Ordinance. As seen in **Noise: Table 6** (above), if the project is mitigated as proposed by staff in proposed Condition of Certification **NOISE-6**, both the project's noise contribution and the cumulative (project plus ambient) noise level would comply with the 45 dBA limit of the Ordinance, measured at any residence.

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 proposed for the general area of the project, but are located at too great a distance to have a measurable 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 would be reduced to less than significant. Therefore, there would be 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

PUBLIC COMMENTS

Gary & Dolores Kuhn

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.*

Response: 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 recommended exterior noise standard will ensure that the power plant noise levels inside the most affected homes will be very low, and well within acceptable limits.

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.*

Response: See the response above.

AGENCY COMMENTS

The County of Alameda commented on staff's interpretation of the Alameda County Noise Ordinance. See "LORS COMPLIANCE," above, for a discussion of this comment.

CONCLUSIONS AND RECOMMENDATIONS

Energy Commission staff concludes that the EAEC, including staff's 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-half mile of the site and the linear facilities, 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 CPM in the first Monthly Construction Report following the start of ground disturbance, a statement, signed by the project manager, stating that the above notification has been performed, and describing the method of that notification, verifying that the telephone number has been established and posted at the site, and giving that telephone number.

NOISE-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.

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 5 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 3-day period, the project owner shall submit an updated Noise Complaint Resolution Form when the mitigation is finally implemented.

NOISE-3 The project owner shall submit to the CPM for review and approval a construction noise control program, consistent with Cal-OSHA regulations (Title 8, Group 15, Article 105, Section 5096). 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 the nearest sensitive receptor. The project owner shall conduct steam blows only during the hours of 7 a.m. to 7 p.m. on weekdays, unless the CPM agrees to longer hours based on a demonstration by the project owner that offsite noise impacts will not cause annoyance.

If a low-pressure continuous steam blow or air blow process is employed, the project owner shall submit a description of this process, with expected noise levels and projected hours of execution, to the CPM, who shall review the proposal with the objective of ensuring that the resulting noise levels will not exceed 45 dBA L_{eq}. 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 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 or air blow(s), the project owner shall notify all residents within one mile of the site of the planned 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 or air 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: The project owner shall notify residents and business owners at least 15 days prior to the first high-pressure steam blow(s). Within five (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 exterior noise level of more than 39 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, as determined by the CPM. Steam relief valves shall be adequately muffled to preclude noise that draws legitimate complaints, as determined by the CPM.

Verification: 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 Site 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.

If the results from the operational noise survey indicate that the noise level due to the plant operations exceeds 39 dBA for any given hour, mitigation measures shall be implemented to reduce noise to a level of compliance with this limit.

If the results from the operational noise survey indicate that pure tones are present, mitigation measures shall be implemented to eliminate the pure tones.

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 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 Following 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 Heavy equipment operation, pile driving, and 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. If no such shielding is provided, horizontal drill rig operation shall be limited to the hours stated above.

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 The Project owner shall remove from residential use, for the life of the project, that dwelling on Kelso Road, southeast of the project site, known as the Franco residence.

<u>Verification:</u> Prior to commercial operation, the project owner shall submit to the CPM copies of legal documents demonstrating that the project owner has control of the Franco residence, along with an affidavit, signed by the project owner, attesting that said residence is no longer used as a residence. The project owner shall submit a renewed affidavit to this effect annually in the Annual Compliance Report.

EXHIBIT 1 –
NOISE COMPLAINT RESOLUTION FORM

East Altamont Energy Center
(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.

EAEC (East Altamont Energy Center LLC) 2001b. Response Set #3 to Energy Commission Data Requests, dated October 9, 2001.

EAEC (East Altamont Energy Center LLC) 2002a. Revised Noise Receptor Data, dated August 1, 2002.

EAEC (East Altamont Energy Center LLC) 2002ppp. Data Response Set 2 (Revised) to Energy Commission Data Requests, dated August 30, 2002 and docketed September 3, 2002.

Federal Transit Administration. 1995. *Transit Noise and Vibration Impact Assessment*. DOT-T-95-16. Harris, Miller, Miller and Hanson, Inc. Burlington, Massachusetts.

Gottlob, Dieter. 1995. "Regulations for Community Noise," Noise/News International, December 1995.

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: 29 CFR § 1910.95

PUBLIC HEALTH

Testimony of Obed Odoemelam, Ph.D.

INTRODUCTION

Operating the proposed East Altamont Energy Center (EAEC) would produce combustion products and other toxics to which the general public and workers might be exposed. Such exposures 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. The non-criteria pollutants are also known as air toxics or toxic air contaminants (TACs) to reflect the nature of their biological interactions. 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 **Public Health: Attachment A**, while the potential for air quality violations is addressed 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 determine if toxic emissions from the proposed EAEC would have the potential to cause significant adverse public health impacts or to violate standards set for the protection of public health. If potentially significant health impacts are identified, staff will evaluate mitigation measures to reduce such impacts to levels of insignificance.

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 "[n]o 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.

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.

SETTING

As noted by the applicant – Calpine, doing business as East Altamont Energy Center LLC – 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.

Few residences are located in the vicinity of the site. The applicant indicated, and staff verified, that there is one "sensitive receptor" within a 3-mile radius of the project site (EAEC 2001a, pages 8.4-8, 8.12-1). This 3-mile radius is the area staff recognizes as potentially significant for the pollutant exposures of concern in this analysis. A sensitive receptor, for purposes of a public health analysis, is an establishment that houses sensitive individuals (e.g., children, the elderly, and individuals with respiratory diseases), such as a school, hospital, a daycare facility, or a nursing home. The sensitive receptor 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 increases. However, 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 individually 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:

Hazard identification – each pollutant of concern is identified along with possible health effects;

Dose-response assessment – the relationship between the magnitude of exposure and the probability of effects is established;

Exposure assessment – the possible extent of pollutant exposures from a project is established for all possible pathways by dispersion modeling; and

Risk characterization – the nature and the magnitude of the possible human health risk is assessed.

Health Effects Assessed

The risk assessment process addresses three categories of health impacts: acute (short-term) health effects, chronic (long-term) non-cancer effects, and cancer risk (also long-term).

Acute health effects result from short-term (1-hour) exposure to relatively high concentrations of pollutants, such as might occur in the event of an accidental spill. Acute effects are temporary in nature, and include symptoms such as irritation of the eyes, skin, and respiratory tract.

Chronic health effects are those which arise from long term exposure to lower concentrations of pollutants. The exposure period is considered to be greater than 12 percent of a lifetime of seventy years. Thus, human exposures of greater than eight years are considered chronic exposures. Chronic health effects include diseases such as cancer, reduced lung function and heart disease.

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

The risk of cancer is assumed to increase with duration of exposure, meaning for example, that the risk from longer exposures to carcinogens would be higher than the risk from shorter exposures. Theoretically, however, a single exposure to a carcinogen can cause cancer. Therefore, cancer is considered to be a more sensitive measure of potential adverse health effects than non-cancer risks.

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 conservative nature 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 is below 10 in a million, staff regards the suggested cancer risk as insignificant and not warranting further analysis for specific action. If the estimate is 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) estimated this fraction 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 regards 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. As mentioned earlier, the potential for significant impacts arising from criteria pollutants is assessed in the **Air Quality** section.

Exhaust from diesel-fueled construction equipment has been established as a potent human carcinogen. Thus 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 reduction in PM10 that results from the use of low-sulfur fuel (which is 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 preventing the cancer and non-cancer risks.

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 the impacts from air toxics tend to be highest in close proximity to the source and quickly drop off with distance. This means that the levels of EAEC's air toxics would be highest in the immediate area and would decrease rapidly with distance. 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). This documentation included:

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, chromium, copper, ethylbenzene, formaldehyde, hexane, lead, mercury, naphthalene, nickel, polycyclic aromatic hydrocarbons (PAHs), propylene oxide, silver, toluene, xylene, zinc, and 1,3-butadiene. The following were considered with regard to a possible cancer risk: acetaldehyde, arsenic, benzene, cadmium, chromium, formaldehyde, PAHs and propylene oxide, and 1,3-butadiene.

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 health 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), with the emergency pump responsible for approximately 0.9 in a million of this risk.

The relative contributions of the project's sources of the considered carcinogens are listed below:

Project Source	Potential Contribution to Total Cancer Risk
Gas turbines	0.00035 in a million
Auxiliary boiler	0.0475 in a million
Cooling tower	0.0000286 in a million
Emergency generator	0.0149 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. Only a relatively few of the many environmental chemicals identified so far as capable of inducing cancer in animals have been shown to cause cancer in humans.

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, coupled with the lack of other nearby toxic sources, staff has determined that the project will not contribute significantly to any area toxic exposure in 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 has determined that the project operation will not result in a disproportionate adverse impact on minority or low-income populations.

RESPONSE TO PUBLIC AND AGENCY COMMENTS

JHS-1 *The commenter's concern includes the potential health risk from exposure to the pollutants from the proposed facility.*

Response. As noted in this analysis, the types of pollutants that are addressed in this Public Health analysis are unlikely (at potentially emitted levels) to pose a significant health risk to anyone in the project area.

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 operation of the proposed natural gas-burning EAEC and its auxiliary equipment are at levels that do not require mitigation beyond that already proposed by the applicant. 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.

The potential impacts from construction-related toxic exposures would 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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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

Testimony of James Adams

INTRODUCTION

The purpose of this analysis is to evaluate the effects of short 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. Staff also discusses the potential direct, secondary (indirect and induced), 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," provides that each Federal agency shall make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies and activities on minority and low income populations and Indian tribes. The order requires the U.S. Environmental Protection Agency (USEPA) and all other federal agencies to develop strategies to address this issue. The Council on Environmental Quality (CEQ) has oversight of the Federal government's compliance with Executive Order 12898 and the National Environmental Policy Act (NEPA). Implementation guidance for EJ under NEPA has been developed by the CEQ, dated December 10, 1997. Although this executive order does not directly apply to the Energy Commission, it provides guidance in assessing EJ issues for the state and does apply to the Western Area Power Administration (Western).

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 potentially 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 $0.33 per square foot of "chargeable covered and enclosed space." (Govt. Code §65995(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 southeast 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 sanitary 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 FSA. 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).

TABLE 1
SOCIOECONOMICS
Employment by Industry: Year 2000

Sector	Alameda & Contra Costa Counties	San Joaquin County
Agriculture/mining	7,200	1,400
Construction	70,000	11,800
Manufacturing	124,700	25,500
Transportation	65,100	14,800
Trade	239,000	43,500
Finance/Insurance Real Estate	107,100	8,400
Services	59,400	47,000
Government	110,700	37,000
Total	783,200	189,400

Source: California EDD 2001, California CDF 2002

IMPACTS

Staff reviewed the EAEC Application for Certification (AFC), the Data Adequacy Response Set 1, Supplement B to EAEC AFC, and all subsequent submittals. 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. The estimated construction payroll would be $49 million. Secondary (indirect and induced) jobs for local workers in other services and trades would likely be created during the construction period (EAEC 2001a, AFC page 8.8-15). In previous cases, applicants have used the IMPLAN Input-Output economic model to provide estimates for secondary employment. In general, for every direct job generated by construction and operation of the EAEC, staff expects an additional one to two jobs to be generated as well.

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 available housing units (5 percent availability rate for 530,000 total 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 Western. 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. However, the Tracy Substation will have to be modified to accommodate the project.

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. Given the relatively small number of calls for police service in the proposed project area, the Sheriff’s Department staff does not expect the EAEC will require any additional officers or equipment, and consequently, will not have a significant impact on law enforcement services and response times. (Alameda County

2001). See the **Worker Safety and Fire Protection** section of this FSA for a discussion of fire department services and responsibilities.

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.

TABLE 2
SOCIOECONOMICS 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 applicant's projections of property value and Alameda County 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 a low-income and/or minority population exists within the potentially affected area of the proposed site. It also includes any potential environmental justice issues that have been identified and whether a disproportionately high adverse human health or environmental impact on minority or low income populations, is likely to result from the proposed action or any alternatives. 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 that the potential affected area encompasses a six-mile radius from the proposed EAEC site. The six-mile radius is consistent with the radius used for staff's cumulative air quality analysis. There may be one or more census blocks or "pockets" within the six-mile radius that have a minority or low-income population greater than 50 percent. 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. Staff attended a workshop and discussed the methodology used in conducting an EJ analysis. No member of the public asked questions or made a comment on the issue.

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 have considered environmental justice impacts in their analyses. There are no significant socioeconomic environmental justice impacts related to the EAEC.

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 IMPACTS

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 may overlap for almost two years from Summer 2003 until Summer 2005. At peak construction in the spring and summer of 2004, the two projects together 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 should start this summer (2002) and will be completed in approximately seven months. Approximately 120 workers will be employed at the Tracy site during peak construction. East Altamont and Tracy Peaker construction periods will not overlap. 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**).

RESPONSE TO PUBLIC COMMENTS

G&DK-2b. *"This plant will also make the values of the surrounding property go down."*

<u>Response:</u> As noted earlier in the discussion on property values, staff does not expect the proposed project will cause a significant adverse impact on property values in the vicinity.

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

Staff believes that the EAEC will not cause a significant adverse direct, indirect 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 $8 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 project will not have any significant disproportionate adverse socioeconomic impacts on minority or low-income populations. Therefore, there are no environmental justice issues. The proposed conditions of certification ensure the compliance with LORS and that anticipated local benefits occur to the extent feasible.

RECOMMENDATION

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 Tri-County area unless:

a) to do so will violate federal and/or state statutes;

b) the materials and/or supplies are not available;

c) qualified employees for specific jobs or positions are not available; or

d) there is a reasonable basis to hire someone for a specific position from outside the local area.

Verification: At least 60 days prior to the start of demolition, 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 by letter 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

ACACA (Alameda County Auditor Controller-Agency) 2001. Personal communication with Sandra Hern, Assistant to the Tax Manager, Alameda County, and James Adams, California Energy Commission, on October 16, 2001.

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TRAFFIC & TRANSPORTATION

Testimony of David Flores

INTRODUCTION

The Traffic and Transportation section of the Final 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, doing business as East Altamont Energy Center, LLC – 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 County 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 LOS 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 in 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, turning west at Kelso Road, then southwest along the Delta Mendota Canal until it reaches the PG&E main pipeline. Total length of the pipeline is approximately 1.8 miles long.

Also, two new 230-kV double-circuit transmission lines between a new EAEC switchyard and an existing 230-kV double-circuit transmission line and a new 230-kV single-circuit transmission between Western’s Tracy Substation and the existing transmission line will span Kelso Road. The existing 230-kV double-circuit transmission line currently spans Mountain House Road.

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 is 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. 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 local 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 Impacts

Traffic Impacts/LOS Standards

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 construction employees on average and approximately 400 construction employees during peak construction months (months 11-16) (EAEC 2001a, AFC pg. 8.10-10)

Workers and deliveries traveling from the east or west on Interstate 205 will access the site via the Grant Line Road interchange. They will travel approximately 7 miles on Grant Line and Byron-Bethany roads to the site at Mountain House and Byron-Bethany roads. Workers traveling from north Contra Costa County would access the site via Byron-Bethany Road. The reverse will be applicable for traffic exiting the project towards Byron- Bethany Road.

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 Alameda County ECAP, the minimum acceptable level of service is defined as LOS 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 traffic (i.e., in the ECAP traffic standards, LOS D or better is an acceptable level of service). 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.

The unsignalized intersections of Byron-Bethany Road with Mountain House Road and Kelso Road currently operate at LOS E conditions. 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 construction trips (225) would be approaching the site from any one of the directions discussed in the **SETTING** 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 that these are reasonable assumptions. 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.

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. Although the addition of construction traffic along this stretch of roadway 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, 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, County of San Joaquin, and Caltrans to offset this project impact. The Applicant has indicated their intent to provide such a plan and staff is proposing a condition of certification to ensure that this happens (see **Condition of Certification TRANS-5**).

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 traffic control plan and implementation program related to the construction of linear facilities will include a discussion on the use of flagmen, advanced warning flashers, and signage for temporary lane closures. In addition, this traffic control plan will include timing of linear facilities construction to take place outside of peak traffic periods, in order to avoid traffic flow disruptions. **TRANS-2** requires the applicant to obtain encroachment permits for any construction activity in public roadways, such as trenching for gas pipelines. **TRANS-7** requires the applicant to repair the affected roads to pre-construction conditions. With implementation of a traffic and transportation control plan as proposed in condition of certification **TRANS-5**, traffic associated with project construction would be minimized during peak hours, by requiring construction traffic to occur during off-peak times.

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 instead 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. Directing project traffic to off-peak periods, combined with 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 a street light for night lighting at the driveway access point and at the intersection of Mountain House Road and Byron-Bethany Road. The street light will be installed on an existing power pole at the designated intersection as required by **TRANS-8.**

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 a street light, which will improve the above described roadway intersections. See **TRANS-5 and TRANS-8** 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. As part of driveway improvements for the entrance to the project site, the applicant shall provide structural roadway shoulder improvements with the final engineered construction plans designed in accordance the Alameda County Public Works Agency requirements (see **TRANS-10**).

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.

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. With mitigation incorporated, staff concludes that impacts to levels of service will be less than significant.

Traffic Hazards

Staff observations of the project area indicate that a potential traffic hazard resulting from winter ground fog or rain conditions, or a traffic flow problem could occur near the jobsite. This existing situation could be exacerbated by ground fog resulting from a vapor plume vented from the EAEC during the operational phase. Potential traffic problems related to vapor plumes are discussed under the Operational Phase heading in this section. Given that Byron-Bethany Road currently operates at LOS E, truck drivers making construction and operation phase deliveries during peak traffic periods could experience major problems turning left from Byron-Bethany Road onto Mountain House Road. Potential problems could be traffic delays and possible front and rear end collisions due to congestion and weather conditions. As indicated earlier, the applicant intends 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. The applicant has also agreed to install fog warning signs in accordance with condition of certification **TRANS-9**.

Emergency Access

The project will not hinder 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. Maintenance of emergency access is also required by **TRANS-5**.

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 and the requirements of **TRANS-4**, staff has concluded that there is no impact.

Transportation of Hazardous Material – Construction Phase

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 transportation and handling of hazardous substances associated with the EAEC can increase roadway hazard potential. Routine transport of hazardous materials, including the requirements of **TRANS-3**, is addressed under the Operational Phase heading in this section. The handling and disposal of hazardous substances are addressed in the **HAZARDOUS MATERIALS MANAGEMENT** and the **WASTE MANAGEMENT** sections of the Final Staff Assessment.

Oversize and Overweight Loads

Transportation of equipment exceeding the load size and weight limits of any roadways will require special permits from the California Highway Patrol and Caltrans. Mitigation measures that ensure compliance with these requirements are discussed under the Operations Phase heading in this section.

Operational Phase Impacts

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 Associated with Transportation of Hazardous Materials

Most of the truck traffic during the EAEC operational phase will result from routine deliveries of hazardous materials. The transportation and handling of hazardous substances can increase roadway hazard potential. According to the AFC, operation of the project will require approximately one delivery per month of anhydrous ammonia solution by licensed hazardous material transporters.

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).

Potential impacts of the transportation of hazardous substances can be mitigated to insignificance by compliance with Federal and State standards established to regulate the transportation of hazardous substances, (see the **HAZARDOUS MATERIALS** section for additional discussion and conclusions on hazardous materials transportation).

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. addition,

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, per the requirements of **TRANS-3** (See the **HAZARDOUS MATERIALS** section for additional discussion and conclusions on hazardous materials transportation).

The existing state highway and county roadway system will not be significantly affected by any increase in truck traffic associated with the operation of the EAEC project.

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.

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 EAEC facility, and the facility's stacks will be lighted in accordance with the requirements of condition of certification **TRANS-6**. Therefore, there will be no impact to air traffic safety.

Vapor Plumes and Ground Fog

The **VISUAL RESOURCES** section of the FSA indicates that the potential exists for vapor plumes to be vented from the proposed cooling towers and HRSG stacks. If vapor plumes were to reach ground level, it could affect safety on the surrounding roadways through creation of a ground fog effect, particularly on cold winter days. The major impact would be expected to occur on Byron-Bethany Road which is adjacent to the proposed facility. The modeling results (See Appendix A for plume modeling analysis) indicated that Byron-Bethany Road could experience approximately 20 hours a year of ground level fog from the cooling towers and HRSG stacks. The modeling also indicated the potential for Mountain House Road to experience plume-fogging events.

Alameda County's Public Works staff also mentioned the potential for winter season "tule" or ground fog in the Byron-Bethany and Mountain House Roads vicinity. The

County staff's concern focused on the possibility of slow moving project construction vehicles being less visible to motorist during the tule fog intervals.

To ensure that any potential impact from ground level fogging from vapor plumes or tule conditions does not result in a hazard for roadway traffic, condition of certification **TRANS-9** recommends the installation of warning signs along Byron-Bethany Road.

CUMULATIVE IMPACTS

Two 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 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 consists of an approximately 5,000-acre new town development 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 for approximately 1,000 homes 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, Bright Development, North Livermore Plan, Auto Auction Facility, and the Old River Specific Plan) have filed annexation applications or are under preliminary review by the various counties or cities in the area. However, they will not be 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 would 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, indirect or cumulative impacts resulting from the construction or operation of the project. Therefore, there are no transportation-related environmental justice issues related to this project.

RESPONSES TO PUBLIC AND AGENCY COMMENTS

Alameda County Community Development Agency/Public Works Agency -Letter dated October 4, 2001

Comment 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 intersections.*

Response: The proposed Conditions of Certification require the installation of a street light at Mountain House Road/Byron Bethany Road intersection near the project site. See discussion in the **Traffic Hazards** section of the report.

Comment 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.*

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.

Comment 3 *The intersection of Mountain House Road at Byron-Bethany Road should be realigned to provide for a 90-degree alignment*.

Response: See staff response under Item 2.

Comment 4 *No access points should be designated on Byron-Bethany Road….*

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.

Comment 5 *For roadway and building set back, the following information should be considered: a. Future width line and special building setback line ….*

Response: The County has not required additional right of way requirements therefore staff has not addressed this as an 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.

Comment 6 *Areas that are reconstructed/realigned should provide a shoulder section along the roadway. The shoulder would allow for optimum recovery and emergency purposes.*

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, it will be submitted with the applicant's final engineered construction plans.

Comment 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.*

Response: Staff has addressed this issue in **TRANS-7**. The applicant will repair portions of Byron-Bethany Road, Mountain House Road and Kelso Road after completion of project construction. Also as provided in **TRANS-7**, repairs to roadway sections shall be in accordance with the Alameda County Trench Cut Study recommendations. The applicant will work with the County to insure compliance with roadway repairs.

Comment 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"……*

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 the **Traffic Hazards** section of report for discussion of impacts.

Comment 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.*

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.

Responses to County of San Joaquin/Department of Public Works
Letter dated March 14, 2002

Comment 1 *The proposed project is required to mitigate impacts to pre-project conditions.*

Response: Staff concurs with this comment. Staff has analyzed the potential project impacts to San Joaquin County, and in various conditions of certification has required that the County of San Joaquin be included in reviewing the Traffic Control Plan, determining repairs to local roadways due to construction activities and that the necessary encroachment permits be obtained through the County.

Comment 2 *In Section 5.9, "the applicant develops a construction traffic control and implementation program, and follows all LORS acceptable to the County of Alameda and Caltrans…" The County of San Joaquin is not mentioned.*

Response: See staff response under item 1.

Comment 3 *Assessment does not identify which routes the workers will be using to and from the proposed site, during both the construction and operational phases.*

Response: Staff has addressed this issue under the Project Specific Impact/Traffic Impacts section of this analysis.

Comment 4 *It is unclear how many employees the proposed project will employ at the site, both during construction and operation of the project.*

Response: Staff has clarified this issue. See Project Specific Impacts/Traffic Impact Section for the number of construction employees on average and during peak construction months.

Comment 5 *In Section 5.9, page 5.9-17, paragraph 1, it is stated "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…San Joaquin County is equally concerned with damages imposed on its roadways….*

Response: See staff response under Item 1.

Responses to County of Alameda/Public Works Agency
Letter dated May 8, 2002

Comment 1 *We have continued concerns with the ability of the pavement, in particular on Mountain House Road where the pavement consists largely of chip seal, to withstand construction traffic loads, and trenching without failure.*

Response: As provided in TRANS-7, repairs to roadway sections shall be in accordance with the Alameda County Trench Cut Study recommendations. The applicant will work with the County to insure compliance with roadway repairs.

Comment 2 *We are concerned with construction traffic slowing to enter the site on these roadways where predominant speed of travel is very fast. This is especially of concern during times when there is "valley fog", and trucks or other slow moving vehicles will be exiting or entering the site from a narrow and unlit County Roadway.*

Response: As indicated under the Construction Phase Impact section of this analysis, staff has recommended condition of certification (TRANS-5) that will require the applicant to develop a construction traffic control plan, which will provide controlled traffic measures to alleviate traffic congestion. Condition of certification TRANS-9 will also require the applicant to work with the County in the installation of fog warning signs for motorist traveling along Byron-Bethany Road near the project site. In addition under condition of certification TRANS-8, the applicant will pay the cost for the installation of a street light/night lighting improvements at the intersection of Mountain House Road/Byron-Bethany Road.

Comment 3 *In addition, the referenced staff report advised that the installation of structural roadway shoulder as part of the installation of the entrance to the site on Mountain House Road be considered as a part of routine review of final engineered construction plans. We agree with this conclusion, and ask that this be reflected in any conditions addressing construction of the driveway access to the site.*

Response: Staff has recommended condition of certification (TRANS-10) that will require the project owner to construct structural roadway shoulder improvements as part of the installation of the driveway entrance into the project site on Mountain House Road.

CONCLUSIONS

Provided that the Applicant develops a construction traffic control and transportation demand implementation program, as required in the conditions of certification, 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 comply with Caltrans and other relevant jurisdictions' limitations on vehicle sizes and weights. In addition, the project owner or its contractor shall obtain all necessary transportation permits from Caltrans and all relevant jurisdictions for roadway use.

Verification: In the Monthly Compliance Reports, the project owner shall submit verification of any permits received during that reporting period. In addition, the project owner shall retain copies of these permits and supporting documentation in its compliance file for at least six months after the start of commercial operation.

TRANS-2 The project owner or their contractor shall comply with Caltrans, the County of San Joaquin, and the County of Alameda limitations for encroachment into public rights-of-way as applicable, 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 The project owner shall ensure that permits and/or licenses are secured from the California Highway Patrol and Caltrans for the transport of hazardous materials.

Verification: The project owner shall include in its Monthly Compliance Reports, copies of all permits/licenses secured by the project owner and/or subcontractors concerning the transport of hazardous substances.

TRANS-4 During construction of the power plant and all related facilities, the project owner shall enforce a policy that all project related parking shall occur in designated parking areas only.

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 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, County of San Joaquin 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 and County of San Joaquin streets are not being exceeded. Specifically, this plan shall include the following restrictions on construction traffic:

a) 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 San Joaquin's LOS D standard and County of Alameda's LOS E standard;

b) Schedule heavy vehicle equipment and building material deliveries as well as the offsite movement of materials and equipment from laydown areas to occur during off-peak hours;

c) Monitoring and compliance with speed limits on Mountain House Road, particularly in the vicinity of the Mountain House school;

d) The construction traffic control and transportation demand implementation program shall also address the following issues for linear facilities:

    1) Timing of pipeline construction (all pipeline construction affecting local roads shall take place outside the peak traffic periods to avoid traffic flow disruptions);

    2) Signing, lighting, and traffic control device placement;

    3) Temporary travel lane closures;

    4) Maintaining access to adjacent residential and commercial properties; and

    5) Emergency access.

Verification: At least 30 days prior to site mobilization, the project owner shall provide to the County of Alameda, the County of San Joaquin 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-6 The HRSG stacks shall have all the lighting and marking required by the Federal Aviation Authority (FAA) so that the stacks do not create a hazard to air navigation.

Protocol: The project owner shall submit to the FAA Form 7460-1 “Notice of Proposed Construction or Alteration” and supporting documents on how the project plans to comply with stack lighting and marking requirements imposed by the FAA.

Verification: At least 30 days prior to the start of construction, the project owner shall provide copies of the FAA Form 7460-1 with copies of the FAA response to Form 7460-1, to the CPM and the Alameda County Public Works Agency – Development Services Department.

TRANS-7 Following completion of project construction of the power plant and all related facilities, the project owner shall repair Mountain House Road, Kelso Road and the portions of Byron-Bethany Road that were affected by the installation of linear facilities, to their pre-construction condition.

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.

2) The project owner shall also notify the County of Alameda, the County of San Joaquin, 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, the County of San Joaquin and Caltrans (as applicable) with a copy of these images.

No later than 60 days after completion of project construction, the project owner shall meet with the CPM, the County of Alameda, the County of San Joaquin, and Caltrans (as needed) to review the photographs of the above described roadways. The agencies will determine and comment on the schedules and actions necessary to complete the repair of identified sections of public roadways to original or as near original condition as possible. Repairs to roadway sections shall be in accordance with the Alameda County Trench Cut Study recommendations.

Following completion of road improvements, if necessary, the project owner shall provide to the CPM letters from the Counties of Alameda and San Joaquin as applicable, stating their satisfaction with the road improvements.

TRANS-8 The project owner shall pay the County of Alameda to implement street light/night lighting improvements at the intersection of Mountain House Road/Byron-Bethany Road.

Verification: 30 days prior to site mobilization, the project owner shall submit to the CPM evidence that the County has been paid to implement the improvements.

TRANS-9 The project owner shall consult with the County of Alameda and submit to the CPM for approval a schedule for the installation of fog warning signs for motorists traveling along Byron -Bethany Road near the project site.

Verification: 30 days prior to start of the construction, the project owner shall provide to the CPM a letter from the County of Alameda stating its satisfaction with the placement and design of the traffic signs warning motorists about the possibility of fog.

TRANS-10 The project owner shall construct structural roadway shoulder improvements as part of the installation of the driveway entrance into the project site on Mountain House Road.

Verification: 30 days prior to site mobilization, the project owner shall submit to the CPM a letter from the County of Alameda stating its approval of the final engineered construction Plans for the driveway structural roadway shoulder improvements are in accordance with County standards.

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.

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COOLING TOWER PLUME
GROUND LEVEL FOGGING ANALYSIS

Testimony of William Walters and Lisa Blewitt

INTRODUCTION

The following provides the assessment of the potential for the East Altamont Energy Center (EAEC) cooling tower plumes to create ground level fogging. Staff completed a modeling analysis for the Applicant's proposed unabated cooling tower design.

PROJECT DESCRIPTION

The Applicant has proposed a linear 19-cell conventional wet cooling tower. The Applicant has not proposed to use any methods to abate visible plumes from the cooling tower. Project data provided by the Applicant (EAEC 2001a, AFC Section 8.11.2.4; EAEC 2001n, pages 21-42, Data Request Responses #6 and #114 to #120; EAEC 2001p, pages 72-76; and EAEC 2001ff, pages 4-6) were used to run the SACTI model to determine cooling tower plume ground level fogging.

COOLING TOWER PLUME GROUND LEVEL FOGGING ANALYSIS

The project site is located near the intersection of Mountain House Road and Byron Bethany Road in unincorporated Alameda County, approximately 1-mile west of the San Joaquin County line, and 1-mile south and east of the Contra Costa County line, and is surrounded by the following:

Byron Bethany Road to the north (N) and east (E).

Lindeman Road and Livermore Yacht Club to the east (E) and northeast (NE).

Kelso Road to the south (S).

Mountain House Road to the west (W).

Currently, the area immediately surrounding the proposed project site is generally agricultural; with the Tracy Substation and Tracy pump station located to the southwest.

The SACTI modeling analysis results for plume fogging are shown in **Table 1**.

Table 1
Staff Cooling Tower Hours of Plume Fogging

Distance from CT (meters)	Plume Direction				Total (hours)
	NNE	NE	ENE	E	
Byron Bethany Road	381	356	406	584	N/A
Lindeman Road	---	1,626	1,270	1,245	N/A
All Hours with Duct Firing (26,280 hours modeled, 195 stagnant)					
100	---	---	4.8	1.1	5.9
200	0.3	2.0	22.3	5.0	29.5
300	---	1.7	22.0	5.0	28.7
400	---	0.2	54.1	6.2	60.5
500	---	---	31.1	3.8	34.9
600	---	---	38.9	4.3	43.2
700	---	---	2.6	0.6	3.2
Daytime Hours with Duct Firing (13,374 hours modeled, 187 stagnant)					
100	---	---	0.9	---	0.9
200	---	---	4.0	---	4.0
300	---	---	4.0	---	4.0
400	---	---	4.9	---	4.9
500	---	---	3.1	---	3.1
600	---	---	3.5	---	3.5
700	---	---	0.5		0.5
Seasonal Daytime Hours with Duct Firing (6,033 hours modeled, 46 stagnant)					
100	---	---	---	---	---
200	---	---	---	---	---
300	---	---	---	---	---
400	---	---	0.5	---	0.5
500	---	---	0.3	---	0.3
600	---	---	0.4	---	0.4
700	---	---	---	---	---

Based on Tracy/Brentwood 1997-1999 meteorological data.

All hours with duct firing represents the worst-case for estimating ground level fogging. Staff estimates show 5.9 hours of fogging at a distance of 100 meters from the cooling tower for the entire three year period, 29.5 hours at a distance of 200 meters, 28.7 hours at a distance of 300 meters, 60.5 hours at a distance of 400 meters, 34.9 hours at a distance of 500 meters, 43.2 hours at a distance of 600 meters, and 3.2 hours at a distance of 700 meters.

Ground level plume fogging occurs in the direction of Byron Bethany Road and Lindeman Road, although distances from the cooling tower show that no ground level plume fogging will reach Lindeman Road. Ground level plume fogging to the northeast, east-northeast and eastern directions will reach Byron Bethany Road.

The modeling results are based on the cooling tower operating data provided by the Applicant. Changes in the cooling tower design or operating philosophy could cause the frequency and direction of plume fogging events to change. Therefore, there is the potential under real world conditions that other nearby roadways, such as Mountain House Road, may experience plume fogging events.

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) 2001n. Data Request Response Set #1. Dated July 9, 2001 and docketed July 10, 2001.

EAEC (East Altamont Energy Center) 2001p. Responses to Data Request Set 2. Dated and docketed August 17, 2001.

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TRANSMISSION LINE SAFETY AND NUISANCE

Testimony of Obed Odoemelam, Ph.D.

INTRODUCTION

The electrical energy from the proposed East Altamont Energy Center (EAEC), if approved, will be available for delivery to the area's 230- kilovolt (kV) electric grid consisting of transmission lines owned by Pacific Gas and Electric (PG&E), the Western Area Power Administration (Western), the Modesto Irrigation District (MID), and the Turlock Irrigation District (TID). According to information from the applicant – Calpine, doing business as East Altamont Energy Center, LLC – this delivery will be made through a new on-site EAEC Switchyard to be owned by Western that would be connected via two new double-circuit 230-kV transmission lines to an existing 230-kV transmission line that will be sectionalized to provide interconnections with Western's Tracy Substation and the Wesley Substation. 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 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 two double-circuit 230- kV lines over the 0.5 mile distance involved. In additions, circuits breakers and controls will be added to the Tracy and Wesley substations. 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 Western, which will assume ownership of the towers and new section of line from Tracy Substation to Tracy East (a new substation associated with EAEC). MID/TID will also follow Western standard designs and will own the new towers and new section of line from Tracy East to Westley Substation. Western designs and practices 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 line electric fields depend on the applied voltage and conductor configuration, and the same 230 kV would 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 transmission line construction and operation plan for incorporation of the measures necessary to minimize the field and non-field impacts consistent with existing health and safety

LORS. 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 distribution 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 recommends specific conditions of certification (**TLSN-3**) 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 in consultation with Western will be responsible in all cases for ensuring compliance with these grounding-related practices within the right-of-way. Staff recommends specific conditions of certification (**TLSN-2**) 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, California Code of Regulations, 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 1993.

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 avoid 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. As a Federal entity, Western transmission lines do not come under CPUC jurisdiction, however, Western lines are designed in accordance with EMF reducing guidelines. 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 Contra Costa 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 Tracy and Westley Substations.

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 switchyard. 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 the 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 Western 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 field levels.

IMPACTS

GENERAL IMPACTS

GO-95, and Title 8 of the California Code of Regulations 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 the applicant 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 unlikely to pose a significant obstruction hazard to utilizing aircraft according to FAA criteria. Therefore no FAA "Notice of Construction or Alteration" will be required. However, the applicant will contact the FAA about the lines, as is 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 Western 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 existing 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 anywhere 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 Western, 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 Western 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

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 at the levels that staff would expect for existing 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 an extent without impacts on line safety, efficiency, reliability and maintainability, staff considers further mitigation as unnecessary but recommends 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 existing lines of similar voltage and current-carrying capacity.

PUBLIC AND AGENCY COMMENTS

There were no specific public or agency comments on the issues addressed in this analysis.

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 Western 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 Western 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 design be approved as proposed. 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 for the proposed design.

CONDITIONS OF CERTIFICATION

By voluntarily agreeing to a joint analysis process with the Energy Commission and to any Conditions of Certification imposed by the Energy Commission for approval of the project, Western is not ceding any jurisdictional authority over federal facilities to the State of California.

TLSN-1 The project shall be constructed for 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 Western EMF reduction guidelines.

Verification: Thirty days before starting construction of the EAEC'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 of GO-95, GO 52, Title 8, Section 2700 et seq. of the California Code of Regulations, and Western's EMF-reduction guidelines. .

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. Should Western become owner of the transmission lines, Western will share information and reports with the CPM.

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. All measurements, reports and mitigation shall be completed prior to turn over of equipment to Western and shall be completed with Westerns approval.

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. Staff will assess the need for further mitigation from the results of such 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.

VISIBLE PLUMES – MODELING RESULTS

Testimony of William Walters

INTRODUCTION

The following provides the assessment of the East Altamont Energy Center (EAEC) Project cooling tower and heat recovery steam generator (HRSG) exhaust stack visible plumes. Staff completed a modeling analysis for both the Applicant's proposed unabated cooling tower and HRSG designs, and potential plume abated designs.

ANALYSIS SUMMARY

Subsequent to the PSA plume analysis document, staff addressed Applicant comments and has remodeled the cooling tower, HRSG and auxiliary boiler using Sacramento meteorological data, and has evaluated cloud cover to determine high visual contrast plume hours. This section presents staff's revised modeling analysis of the cooling tower, HRSG and auxiliary boiler plumes. Data presented in the PSA plume analysis document that is not relevant to the final modeling approach has been purposely left out for clarity and easier reading.

A meteorological data comparison has been added to this analysis to show that staff's use of a Sacramento meteorological data set is an appropriate proxy for the project site, which is established through comparison with the Tracy/Brentwood meteorological data set provided by the Applicant. The numeric meteorological data comparison is presented in **Tables 1** and **2**. Staff chose to use the Sacramento meteorological data set because it includes visual obstruction and cloud cover data not available in the Tracy/Brentwood data set.

The cooling tower and HRSG plumes are predicted to occur more than 10% of seasonal daylight no rain no fog hours and are therefore analyzed in more depth with consideration of cloud cover to determine high visual contrast plume hours. **Tables 4** and **5** present the revised cooling tower modeling results, and **Table 7** provides the high visual contrast plume frequencies. Following **Table 7** are the 10th percentile plume dimensions determined for the cooling towers during high visual contrast hours. **Tables 9** and **10** present the revised HRSG modeling results, and **Table 11** provides the high visual contrast plume frequencies. Following **Table 12** are the 10th percentile plume dimensions determined for the HRSGs during high visual contrast hours.

The auxiliary boiler plumes were not predicted to occur more than 10% of seasonal daylight no rain no fog hours. **Table 13** presents the auxiliary boiler plume modeling results.

PROJECT DESCRIPTION

The project includes a linear 19-cell conventional wet cooling tower. The Applicant has not proposed any methods to abate visible plumes from the cooling tower.

The project includes three separate turbine/heat recovery steam generator (HRSG) systems, each with separate exhaust stacks. The project features very large duct firing capacity, which increases exhaust moisture content, and also features very low exhaust temperatures when duct firing, which combined with the high exhaust moisture content causes a much higher plume frequency potential than in other recent 7F frame turbine projects. The Applicant has not proposed to use any methods to abate visible plumes from the HRSG exhausts.

The project also includes an auxiliary boiler that will be used to provide steam as necessary for supplemental uses.

METEOROLOGICAL DATA ANALYSIS

Staff has reviewed the 1997-1999 Tracy/Brentwood, 1976 Stockton, and 1990-1993 Sacramento meteorological data sets and has determined that the Sacramento meteorological data set provides the most defendable proxy for this project location.

The Applicant discontinued using the Tracy/Brentwood data because present weather and visibility data were not available. Staff believes that the Tracy/Brentwood data is still the most useful data set for certain analyses that do not consider present weather or visibility, such as ground level plume fogging. Staff also believes that the conditions reflected by the Tracy/Brentwood data, namely temperature and relative humidity, should be reflected in the data set that is used to substitute for the Tracy/Brentwood data.

Table 1 compares monthly ambient data from various locations around the project site. **Table 1** shows that the average minimum, maximum, and medium temperatures are very similar for each of the locations shown in the table. Therefore, any of these locations should provide reasonable temperature data for staff's analysis of the project plumes. Unfortunately, similar statistics regarding relative humidity are not available for all of these weather monitoring locations, but they do not exist in the meteorological data files for Tracy/Brentwood, Sacramento and Stockton (see Table 2). Staff observes that the site is primarily influenced by winds coming from the Bay Area. Since the Tracy/Brentwood data set provides the nearest and most accurate temperature and relative humidity data for the project site, staff believes that the most comparable meteorological data set that also has weather conditions and visibility data should be used to determine plume impact potential for this site.

Table 1
Comparison of Average Temperatures

Byron	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Avg. High	53 °F	61 °F	65 °F	71 °F	79 °F	86 °F	92 °F	91 °F	86 °F	77 °F	63 °F	53 °F
Avg. Low	36 °F	40 °F	44 °F	47 °F	52 °F	57 °F	60 °F	60 °F	57 °F	51 °F	43 °F	37 °F
Mean	45 °F	51 °F	55 °F	59 °F	66 °F	72 °F	76 °F	76 °F	72 °F	65 °F	54 °F	46 °F
Brentwood	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Avg. High	53 °F	60 °F	65 °F	71 °F	78 °F	85 °F	90 °F	89 °F	85 °F	77 °F	63 °F	53 °F
Avg. Low	35 °F	40 °F	42 °F	45 °F	50 °F	55 °F	56 °F	56 °F	54 °F	49 °F	42 °F	36 °F
Mean	45 °F	50 °F	54 °F	59 °F	65 °F	71 °F	74 °F	73 °F	70 °F	63 °F	53 °F	45 °F
Stockton	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Avg. High	53 °F	61 °F	66 °F	72 °F	80 °F	88 °F	93 °F	92 °F	87 °F	78 °F	64 °F	54 °F
Avg. Low	35 °F	39 °F	42 °F	45 °F	49 °F	54 °F	56 °F	55 °F	53 °F	48 °F	41 °F	36 °F
Mean	45 °F	51 °F	54 °F	59 °F	65 °F	72 °F	75 °F	74 °F	71 °F	64 °F	53 °F	45 °F
Tracy	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Avg. High	53 °F	61 °F	66 °F	72 °F	80 °F	88 °F	93 °F	92 °F	87 °F	78 °F	64 °F	54 °F
Avg. Low	35 °F	39 °F	42 °F	45 °F	49 °F	54 °F	56 °F	55 °F	53 °F	48 °F	41 °F	36 °F
Mean	45 °F	51 °F	54 °F	59 °F	65 °F	72 °F	75 °F	74 °F	71 °F	64 °F	53 °F	45 °F
Sacramento	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Avg. High	52 °F	60 °F	64 °F	71 °F	80 °F	87 °F	93 °F	92 °F	87 °F	77 °F	63 °F	52 °F
Avg. Low	37 °F	41 °F	43 °F	45 °F	50 °F	55 °F	58 °F	58 °F	55 °F	50 °F	43 °F	37 °F
Mean	45 °F	51 °F	54 °F	58 °F	65 °F	72 °F	76 °F	75 °F	72 °F	64 °F	53 °F	45 °F

Source: www.weather.com

Table 2 compares the temperature and relative humidity data of the three meteorological data sets.

Table 2
Meteorological Data Set Relative Humidity Comparison

Meteorological Data Set	Average Temperature	Average Relative Humidity
Tracy Brentwood 1997-1999	60.9°F	69.0%
Stockton 1976	59.8°F	59.6%
Sacramento 1990-1993	60.1°F	66.4%

Table 2 shows that the Sacramento data more closely resembles the Tracy/Brentwood data than does the Stockton data. Additionally, the Stockton data set includes only a single year of data. Staff considers multiple years of meteorological data to be necessary when modeling plume potential due to the variability in weather patterns from year to year. Considering these factors, staff does not believe that the Stockton data adequately reflects the conditions at the project site. Therefore, staff selected the Sacramento meteorological data set for the EAEC plume analysis.

CLOUD COVER DATA ANALYSIS METHOD

A plume frequency of 10% of seasonal (November through April) daylight hours is used as an initial plume impact threshold trigger, where if exceeded, the analysis is further refined by performing a high visual contrast hours analysis of the seasonal daylight no rain no fog plume hours. The high visual contrast hours analysis methodology is provided below:

The Energy Commission has identified a “clear” sky category during which plumes have the greatest potential to cause adverse visual impacts. For this project the meteorological data set[1] used in the analysis categorizes total sky cover and opaque sky cover in 10% increments. Staff has included in the “Clear” category a) all hours with total sky cover equal to or less than 10% plus b) half of the hours with total sky cover 20-100% that have a sky opacity equal to or less than 50%. The rationale for including these two components in this category is as follows: a) plumes typically contrast most with sky under clear conditions and, when total sky cover is equal to or less than 10%, clouds either do not exist or they make up such a small proportion of the sky that conditions appear to be virtually clear; and b) for a substantial portion of the time when total sky cover is 20-100% and the opacity of sky cover is relatively low (equal to or less than 50%), clouds do not substantially reduce contrast with plumes; staff has estimated that approximately half of the hours meeting the latter sky cover and sky opacity criteria can be considered high visual contrast hours and are included in the “clear” sky definition.

[1] This analysis uses an Hourly US Weather Observations (HUSWO) data set.

COOLING TOWER VISIBLE PLUME MODELING ANALYSIS

COOLING TOWER DESIGN PARAMETERS

Using information provided in the Applicant's AFC (EAEC 2001a, AFC Section 8.11.2.4), Data Request Responses #6 and #114 to #120 (EAEC 2001n, pages 21-42; EAEC 2001p, pages 72-76; EAEC 2001ff, pages 4-6), and revised Data Response 117 (EAEC 2001gg, pages 1-4), staff performed an independent psychrometric analysis and dispersion modeling analysis to determine the expected frequency and dimensions of the project's proposed unabated wet cooling tower.

The following are the relevant cooling tower design characteristics, presented below in **Table 3**, were determined through a review of the Applicant's AFC and Data Request Responses, and through additional engineering calculations.

Table 3
Cooling Tower Design Parameters

Parameter	Cooling Tower Design Parameters
Stack Height[1]	17.37 meters
Number of Cells[1]	19 Cells (1 by 19 configuration)
Equivalent Stack Diameter[2]	44.72 meters (10.26 m per cell)
Tower Dimensions[1]	313 meter length by 16.4 meter width
Tower Heat Rejection[1]	807 MW/hr (duct fired)
Tower Inlet Air Flow Rate[1]	17,191 kg/s
Liquid to Gas (L/G) Ratio[1]	1.03 (hot and annual avg. weather), 0.57 (cold weather)
Exhaust Temperature[2]	48.6°F to 98.6°F
Exit Velocity[2]	Calculated hourly based on other parameters
Exhaust mass flow rate[2]	137,250,000 to 140,951,000 lbs/hr
Exhaust Molecular Weight[3]	28.8
Moisture Content (% by weight) [2]	0.73% to 3.30%

1. Source: EAEC 2001a, AFC Section 8.11.2.4, EAEC 2001n, pages 21-42, EAEC 2001p, pages 72-76, EAEC 2001ff, pages 4-6, and EAEC 2001gg, pages 1-4.
2. Source: Staff calculations based on or interpolated from the Applicant's cooling tower data.
3. Source: Staff assumption.

The exhaust temperature and exhaust mass flow rate values were calculated for the hourly ambient conditions modeled through linear interpolation and extrapolation of the data provided by the Applicant for three ambient conditions. The exhaust moisture content was determined by assuming saturated conditions at the calculated exhaust temperature.

Staff notes that the cooling tower parameters presented by the Applicant, particularly the low operating liquid to gas flow rates assumed during cold weather, may not reflect real world cooling tower operating parameters and may underestimate plume potential from the final cooling tower design once it is built and operating. In particular, staff is concerned with the potential need to reduce the tower air flow in cold weather to reduce the potential for ice formation within the tower.

It is the Applicant's contention that the reasonable worst-case plume formation scenario can be based on the plant is using their duct burners from 10 am to 8 pm to meet peak demand. Staff has incorporated this as a reasonable worst-case assumption in the modeling analysis. However, it should be noted that there are no specific requirements that would prohibit duct firing from 8 pm through 10 am. As duct firing increases the steam load, it also increases the heat rejection load to the cooling tower. Thus, the effect of this reasonable worst-case assumption is to substantially drop the exhaust temperature and moisture content from the cooling tower during the overnight and early morning hours. Therefore, the modeled plume frequencies and plume dimensions are determined to be lower than they might be if duct firing is employed from 8 pm through 10 am.

Additionally, the Applicant has indicated that they are going to operate the cooling tower without substantially reducing air flows whether operating with or without duct firing. When the cooling load is reduced the cooling tower could be operated with fewer cells on-line, with lower air flow through the cells, or without any change in the flow rate, as is assumed by the Applicant. Staff considers the Applicant's operating approach to be a de facto plume abatement method, which the model indicates will reduce the frequency of plumes. If the project owner were to employ either of the other two operating methods, the modeled plume frequencies would not change substantially from those modeled for the duct firing case, but the plume dimensions would be smaller due the reduced overall water mass flow rate being exhausted from the tower.

STAFF COOLING TOWER PLUME MODELING RESULTS

Staff modeled the cooling tower plumes using both a modified version of the Combustion Stack Visible Plume (CSVP) model and the Seasonal/Annual Cooling Tower Impact (SACTI) model. In general, staff finds the CSVP model to be more useful for predicting the frequencies and dimensions of the cooling tower plumes. However, the CSVP and SACTI modeling tools each have strengths and limitations. The CSVP model indicates hours when no plume is expected, thereby giving more accurate numbers for the plume frequencies. In addition, the CSVP model uses hourly meteorological data, which allows for greater specificity in the plume frequency analyses. SACTI can be used to provide information about the potential for ground level fogging (which is covered in the Traffic and Transportation section of this FSA), and can be used for plume dimension results comparison to determine if the CSVP model has over or under-predicted the dimensions of the plumes. Another difference is that the SACTI model is designed to model multiple cell cooling towers, whereas the CSVP model is a single point source model. Because the CSVP model is a single point source model, staff used both an equivalent stack diameter modeling approach and a single cell modeling approach (evaluated later in this report), when using CSVP for the analysis of plume dimensions.

As stated above, the CSVP model provides more accurate information about plume frequency. **Table 4** provides the CSVP model visible plume frequency results using the Sacramento 1990 to 1993 meteorological data.

Table 4
Staff Predicted Hours with Cooling Tower Steam Plumes
Sacramento 1990 to 1993 Meteorological Data

		Duct Fired		No Duct Firing		Limited Duct Firing	
	Total Hours Available	**Plume (hr)**	**Percent**	**Plume (hr)**	**Percent**	**Plume (hr)**	**Percent**
All Hours	34,980	20,302	58.0%	12,898	36.9%	15,301	43.7%
Daylight Hours	17,865	6,281	35.2%	3,187	17.8%	4,822	27.0%
Seasonal Daylight	8,004	4,772	59.6%	2,658	33.2%	4,187	52.3%
Seasonal* Daylight No Rain No Fog Hours	6,339	3,116	49.2%	1,098	17.3%	2,555	40.3%

*Seasonal conditions occur from November through April.

Staff's analysis of plume frequencies and plume sizes is based on the limited duct firing case. However, as can be seen in **Table 4**, the plume frequencies could be higher than that assumed for the limited duct firing case if there are more hours of duct firing, or lower if there are fewer hours of duct firing than assumed in the limited duct firing case.

For comparison the CSVP and SACTI model predicted plume size characteristics for the duct firing case are provided in **Table 5**. Staff found an error in the original stack diameter that staff input to the SACTI model. The corrected SACTI modeling results are reflected in this table.

Table 5 indicates that the SACTI model predicts smaller plumes than the equivalent stack CSVP modeling results and larger plumes than the CSVP single cell modeling approach. The SACTI model groups meteorological data and uses only 25 ambient temperature and relative humidity combinations and 9 separate wind speed and stability combinations, while there are actually over 19,600 combinations of temperature, relative humidity, wind speed and stability in the Sacramento meteorological data file, which are all modeled individually by the CSVP model. Therefore, the SACTI plume size results are marked by large step changes while the CSVP model provides a much smoother interpretation of the plume size curve. Additionally, the SACTI model does not model calm hours, which will create differences in the frequency size distribution results, as calm hours would be expected to have very large, specifically very high, plumes. Therefore, staff prefers that the CSVP model over SACTI because it provides a more accurate frequency size distribution of the plumes.

Table 5
Staff Predicted Duct Firing Cooling Tower Steam Plume Dimensions
Sacramento 1990 to 1993 Meteorological Data

	CSVP Model (Equivalent Stack – Duct Firing)			**SACTI Model (Duct Firing)***			**CSVP Model (Single Cell - Duct Firing)**		
	Length (m)	**Height (m)**	**Width (m)**	**Length (m)**	**Height (m)**	**Width (m)**	**Length (m)**	**Height (m)**	**Width (m)**
All Hours									
50%	75	95	40	50-60	20-30	40-60	15	27	9
10%	3,490	375	230	800-900	90-100	140-160	584	139	49
Maximum	>5,000	5,186	2,070	>10,000	700-800	1,000-1,200	>5,000	901	686
Seasonal Daylight No Rain No Fog Hours**									
50%	No Plume	No Plume	No Plume	30-40	20-30	40-60	No Plume	No Plume	No Plume
10%	375	389	85	300-400	90-100	120-140	73	64	19
Maximum	>5,000	4,978	1,656	6000-7000	700-800	600-800	3,761	860	421

No Plume – Plumes are not predicted to occur at the listed frequency.
* SACTI height results are from the exhaust height of the cooling tower (17.37 meters), the length results do not include the length of the tower (313 meters). SACTI does not model the calm wind hours which comprised 5,127 hours for all hours, or 14.7% of all hours, and of the all hours plumes and 679 hours for seasonal daylight no rain no fog hours, or 10.7% of seasonal daylight no rain no fog hours. Calm condition plumes are very tall plumes due to the lack of wind induced horizontal mixing.
** Seasonal conditions occur from November through April.

Staff completed a confirmation modeling analysis using ISCST3 as shown in **Table 6**:

Table 6
Confirmation Modeling Analysis Results
Tracy/Brentwood 1997 to 1998 Meteorological Data

Date Modeled	ISCST3		CSVP (Equivalent Diameter Approach)		CSVP (Single Cell Approach)	
(YYMMDDHH)	Length (m)*	Height (m)	Length (m)*	Height (m)	Length (m)*	Height (m)
97011410	180	95	184	184	36	38
97011417	170	120	189	505	38	80
98122112	20	65	32	139	7	34
99010313	>7,000	450	>5,000	2,460	1,235	435
99020912	175	35	87	52	17	22
99042606	300	55	145	82	28	25

* These results are length from the tower, and do not include the length of the 313 meter cooling tower.

This modeling study indicates that the CSVP equivalent stack modeling approach provides conservative, but reasonable, plume dimensions, while the single cell approach dramatically underestimates the plume dimensions. Generally, the plume height may be moderately overestimated due to an increase in the buoyancy induced plume rise of the “combined” stacks using the equivalent stack diameter approach, and the lack of downwash calculations in CSVP. For certain circumstances, such as 100% relative humidity (such as during model hour 99010313) and during high wind conditions (such as during model hours 99020912 and 99042606) the plume length tends to be underestimated, while the plume height remains somewhat overestimated. However, calm hour plume sizes, using staff’s 1 m/s wind speed assumption, will generally be grossly underestimated. Due to the uncertainties in the meteorological conditions and the cooling tower exhaust conditions, staff believes that a conservative modeling analysis as provided by the equivalent diameter modeling approach is appropriate to determine potential visual impacts from cooling tower plumes, but staff recommends additional confirmation of the specific plume dimensions to be used in plume simulations.

Staff uses a plume frequency of 10% of seasonal (November through April) daylight no rain no fog high visual contrast hours as the threshold that triggers the need for a study of the visual impacts from the plumes. Both models predicted large plumes for more than 10% of seasonal daylight hours. Therefore, a cloud cover data analysis has been performed to determine the number of plume hours that occur during hours that are defined as high visual contrast hours. **Table 7** presents the results of the CSVP model plume hours cloud cover data analysis.

Table 7
Staff Predicted Cooling Tower Plume Hours by Cloud Cover Category

Plume Hours by Cloud Cover Type					
All		**Clear**		Scattered/Broken/Overcast	
Hrs	%	**Hrs**	**%**	Hours	%
2,555	40.3	**1,048**	**16.5**	1,507	23.8

* Percentiles calculated by dividing the number of plume hours by the reference number of seasonal daylight no rain no fog hours (6,339).

Cooling tower plumes will occur during clear conditions a total of 1,048 hours or 16.8% of seasonal daylight no rain no fog hours.

The 10th percentile clear sky plume dimensions are estimated by the CSVP model, using the equivalent stack diameter approach, as follows:

Length – 53 meters (174 feet)
Height – 91 meters (298 feet)
Width – 37.8 meters (124 feet)

The actual 10th percentile clear sky plume dimensions could be larger than those provided above if there are more hours of duct firing than assumed in the limited duct firing case, or smaller if there are fewer hours of duct firing than assumed in the limited duct firing case. These dimensions include the height of the tower (17.37 meters) but do not include the length of the tower, which is 313 meters long. Therefore, the actual visible plume length is 313 meters (1,027 feet) plus a portion of the 53 meter plume length, which depends on the angle of the wind relative to the long axis of the cooling tower.

The plume sizes given above were used by staff to complete the visual simulation of the cooling tower plumes during clear sky conditions. For the simulation the plume width is adjusted for the number and diameter of the cooling tower cells, and a vertical plume dimension component is determined by the model using an initial vertical dispersion term and standard rural land use classification calculations.

HRSG VISIBLE PLUME MODELING ANALYSIS

Staff evaluated the Applicant's Data Response #7 and #119 (EAEC 2001n, pages 42-61; EAEC 2001p, pages 74-76; EAEC 2001ff, pages 4-6) and performed an independent psychrometric analysis and dispersion modeling analysis. The CSVP model was used to estimate the worst-case potential plume frequency, and provide data on predicted plume length, width, and height for each HRSG stack.

HRSG PARAMETERS

Based on the revised stack exhaust parameters anticipated by the Applicant for each HRSG stack, the frequency and size of visual plumes can be estimated. The operating data for these stacks are provided in **Table 8**. The Applicant provided the revisedHRSG exhaust temperature parameters in revised Data Response 119 (EAEC 2001gg, pages 4-6).

Table 8
HRSG Stack Exhaust Parameters

	HRSG Stack Exhaust Parameters		
Parameter	**Unabated HRSG Full Load – With Duct Firing and Power Augmentation***	**Unabated HRSG Full Load – With Duct Firing, No Power Augmentation**	**Unabated HRSG Full Load – No Duct Firing or Power Augmentation**
Stack Height	53.34 meters		
Stack Diameter	5.64 meters		
Exhaust Temperature	342°K (155°F)	342°K (155°F)	360°K (188°F)
Exit Velocity	Calculated for each hour modeled		
Exhaust Mass Flow Rate	3,414,714 to 4,128,241 lbs/hr	3,196,873 to 3,910,400 lbs/hr	3,108,980 to 3,822,507 lbs/hr
Exhaust Molecular Weight	28.5 lbs/lb-mol (est.)		
Moisture Content (% by wt)	9.03 to 9.36%	7.15 to 7.48%	5.30 to 5.63%

* Unabated worst-case

STAFF HRSG PLUME MODELING ANALYSIS

The predicted HRSG visible plume frequencies estimated by the CSVP model using the revised HRSG exhaust temperatures and the Sacramento meteorological data are shown in **Table 9**.

Table 9
Staff Predicted Hours with HRSG Steam Plumes
Sacramento 1990-1993 Meteorological Data

		Staff Modeling Results	
		Unabated HRSG Worst Case	
	Available (hr)	**Plume (hr)**	**Percent**
All Hours	34,980	24,394	69.7%
Daylight	17,865	8,787	49.2%
Seasonal Daylight*	8,004	6,442	80.5%
Seasonal Daylight No Fog/No Rain*	6,339	4,777	75.4%
		Unabated HRSG – Duct Firing	
	Available (hr)	**Plume (hr)**	**Percent**
All Hours	34,980	18,148	51.9%
Daylight	17,865	5,433	30.4%
Seasonal Daylight*	8,004	4,433	55.4%
Seasonal Daylight No Fog/No Rain*	6,339	2,787	44.0%
		Unabated HRSG – No Duct Firing or Power Augmentation	
	Available (hr)	**Plume (hr)**	**Percent**
All Hours	34,980	4,465	12.8%
Daylight	17,865	1,006	5.63%
Seasonal Daylight*	8,004	995	12.4%
Seasonal Daylight No Fog/No Rain*	6,339	203	3.20%
		Limited Duct Firing	
	Available (hr)	**Plume (hr)**	**Percent**
All Hours	34,980	7,901	22.6%
Daylight	17,865	3,156	17.7%
Seasonal Daylight*	8,004	3,032	37.9%
Seasonal Daylight No Fog/No Rain*	6,339	1,740	27.4%

* Seasonal conditions occur from November through April.
Worst case - Duct firing and power augmentation on at maximum capacity.

Staff's analysis of plume frequencies and plume sizes is based on the limited duct firing case. However, as can be seen in **Table 9**, the plume frequencies could be much higher than that assumed for the limited duct firing case if there are more hours of duct firing or a significant amount of hours with steam injection power augmentation, or somewhat lower if there are fewer hours of duct firing than assumed in the limited duct firing case.

Table 10 presents the staff predicted HRSG plume dimensions for the limited duct firing case.

Table 10
Staff Predicted HRSG Steam Plume Dimensions (meters)
Revised HRSG Operating Data
Sacramento 1990-1993 Meteorological Data

	Limited Duct Firing Case		
All Hours	**Length (m)**	**Height (m)**	**Width (m)**
50%	No Plume	No Plume	No Plume
10%	637	178	54
5%	1,669	224	106
Maximum	>5,000	1,430	2,095
Daylight Hours			
50%	No Plume	No Plume	No Plume
10%	160	126	27
5%	452	263	52
Maximum	>5,000	1,430	2,045
Seasonal Daylight Hours No Fog No Rain*			
50%	No Plume	No Plume	No Plume
10%	142	127	25
5%	212	190	34
Maximum	3,995	1,388	459

* Seasonal conditions occur from November through April.
No Plume – Plumes are not predicted to occur at the listed frequency.

The actual plume dimensions could be larger than those shown in **Table 10** if there are more hours of duct firing than assumed in the limited duct firing case, or if there are a significant amount of hours with steam injection power augmentation; or smaller if there are fewer hours of duct firing than assumed in the limited duct firing case. The maximum plume dimensions occur when the relative humidity is 100%, which are generally characterized as hours with low visibility (rain, fog, or low visual range). Plume dimensions decrease rapidly as the relative humidity decreases from 100%.

A cloud cover data analysis has been performed to determine the number of HRSG plume hours that occur during clear sky condition hours. **Table 11** presents the results of the cloud cover data analysis.

Table 11
Staff Predicted HRSG Plume Hours Cloud Cover*

Plume Hours by Cloud Cover Type					
All		Clear		Scattered/Broken/Overcast	
Hours	%	Hours	%	Hours	%
1,740	27.4	745	11.8	995	15.7

* Percentiles calculated by dividing the number of plume hours by the reference number of seasonal daylight no rain no fog hours (6,339).

HRSG plumes will occur a total of 745 hours or 11.8% of clear, seasonal daylight no rain no fog hours.

The 10th percentile clear sky plume dimensions are estimated by the CSVP model as follows:

Length – 57.0 meters (187 feet)
Height – 87.0 meters (285 feet)
Width – 14.5 meters (47 feet)

As noted previously, the actual 10th percentile clear sky plume dimensions could be larger or smaller depending on the actual schedule for duct firing and steam injection.

The plume sizes given above were used by staff to complete the visual simulation of the HRSG plumes during clear sky conditions. For the simulation the plume width is adjusted for the diameter of the HRSG exhaust, and a vertical plume dimension component is determined by the model using an initial vertical dispersion term and standard rural land use classification calculations. It is possible that the plumes from the HRSGs will combine into one larger plume mass under certain conditions.

AUXILIARY BOILER VISIBLE PLUME MODELING ANALYSIS

The Applicant provided the following exhaust parameters for the auxiliary boiler.

Table 12
Auxiliary Boiler Exhaust Parameters

Parameter	Cooling Tower Design Parameters
Exhaust Temperature	325°F
Exhaust mass flow rate	110,513 lbs/hr
Exhaust Molecular Weight	27.71
Moisture Content (% by weight)	11.43%

Table 13 provides the CSVP model visible plume frequency results using the Sacramento meteorological data.

Table 13
Staff Predicted Hours with Auxiliary Boiler Steam Plumes
Sacramento 1990 to 1993 Meteorological Data

		Unabated Cooling Tower	
	Available (hr)	Plume (hr)	Percent
All Hours	34,980	6,885	19.7%
Daylight	17,865	1,059	5.9%
Seasonal Daylight	8,004	1.054	13.2%
Seasonal Daylight No Rain No Fog Hours*	6,339	371	5.9%

* Seasonal conditions occur from November through April.

A plume frequency of 10% of seasonal (November through April) daylight no rain/fog hours is used as a plume impact study threshold trigger. The CSVP model predicted plume frequencies less then 10% of seasonal daylight no rain/fog hours. Considering the low frequency of plume formation staff did not complete a plume dimension analysis for the auxiliary boiler.

It should be noted that the plume frequency results are based on continuous auxiliary boiler operation. The auxiliary boiler, however, will not operate 8760 hours per year, thereby further reducing the frequency of plume formation.

PLUME ABATEMENT METHODS

Effective plume abatement methods include air cooled condensers or wet/dry cooling systems for cooling tower plume abatement; and increasing stack temperature for HRSG plume abatement. As a comparison to the EAEC project, the proposed Tesla Power Plant Project (Tesla) is proposing a plume abated cooling tower and has higher HRSG exhaust temperatures than those proposed by EAEC, which for the Tesla project have resulted in predicted plume frequencies that are less than the significance thresholds that require visual impact analysis (i.e. insignificant plume impacts).

It should be noted that staff tried to obtain information regarding the ability to incorporate an economizer bypass to mitigate HRSG plumes, but the Applicant objected to the data request (EAEC 2001z) and did not provide the requested information.

COOLING TOWER PLUME ABATEMENT METHODS

Cooling tower plumes can be abated through cooling apparatus design modification. Two potential abatement methods are provided for discussion: 1) air-cooled condensers; and 2) wet/dry cooling systems. The use of once-through cooling would also eliminate plumes; however, this option is not available at this project location.

Air-Cooled Condensers (Dry Cooling)

Air-cooled condensers, in place of a wet cooling tower, completely eliminate the potential for plume formation; however, this technology is much more expensive (as much as 10 times as expensive) than a traditional cooling tower, requires more space, and creates a much higher structure that may itself impact project aesthetics. The operating costs are also higher due to the higher electrical demand for the fans. Based solely on economic criteria, a project developer will generally only consider air-cooled condensers for power plant installations when water constraints will not allow for wet cooling technologies. However, due to overriding environmental considerations (i.e. water use and visual impacts) many states, such as New York, Oregon, and Colorado to name a few, have mandated dry cooling for all or most of their new power projects that have been licensed within the last 15 years.

Wet/Dry Cooling Towers

Wet/dry cooling tower systems can also be used to lessen or completely eliminate plume formation during normal weather conditions. Wet/dry systems are also more expensive (approximately 1.5 to 3 times as expensive) than traditional cooling towers and have higher operating costs. However, the relative cost of these systems is decreasing as their use has become more frequent and more cooling tower manufacturers are entering this market. The size of these systems is dependent on the specific design; however, in general these towers will either increase the footprint size or the height compared to a conventional wet cooling tower. Water use will decrease in proportion to the heat duty of the dry section of the wet/dry tower. Noise emissions from wet/dry towers are dependent on the specific design, and are generally thought to be higher than for wet cooling, but in some cases are essentially equivalent to the noise emissions from conventional wet cooling towers.

Over-Sizing Tower Air Flow

Increasing tower air flow rates (i.e. decreasing L/G) can reduce the frequency, size and density of plume formation. The increase in air flow causes the exhaust temperature and moisture content to move down the saturation line which then requires less dispersion to dissipate the plume, resulting in less frequent and shorter plumes. This may be accomplished through providing oversized variable speed fans and motors and additional air intake area. However, this method is not as effective as the other plume abatement methods and would increase the size of the cooling tower, which may increase the capital cost as much as a wet/dry or hybrid design and would likely have a higher associated operating cost. Whether by design or not, the Applicant’s cooling tower design in effect uses this method to reduce plume formation.

Power plants have recently been proposed that use all three of these design modifications to eliminate or mitigate cooling tower plumes. The appropriate abatement design is based on each project’s plume sensitivity. According to Don Dobney of Marley Cooling Tower (Dobney 2001), due to the reasonably high winter temperatures in most of California, it is generally cheaper to add a small dry cooling section (i.e. like their “ClearFlow” design) to a cooling tower than oversize the airflow. This method would also be more effective and have lower operating costs.

HRSG PLUME ABATEMENT METHODS

There are two methods that can be used alone or together, to reduce HRSG plume formation. These two methods are 1) increasing the stack temperature, and 2) decreasing the water content of the exhaust.

Increase Stack Temperature

Stack temperature can be increased by transferring less heat in the HRSG. This method is relatively easy to monitor, but will result in a small loss in efficiency and total MW production. This method is used at the Crockett facility, where an economizer bypass is used to increase stack temperatures to eliminate HRSG plumes during cold weather. This method has also been proposed for several other facilities, including two other facilities proposed by the EAEC project Applicant.

Decrease Exhaust Water Content

The water content in HRSG exhausts comes from three major sources: 1) water from the ambient inlet air; 2) water produced in the combustion process; and 3) water added for power augmentation. It is not feasible or desirable to reduce the water content of the ambient air. Therefore, the most feasible method for the EAEC project to reduce the HRSG exhaust water content is to reduce duct firing or power augmentation. As can be seen in the plume frequency results provided in Table 5 reducing duct firing and power augmentation can lower the plume frequency significantly.

This method is generally not considered desirable to project applicants due to the fact that it restricts the operations and power output of the facility. However, it should be noted that power produced by duct firing is less efficient than power produced without duct firing, so limiting duct firing actually increases overall fuel efficiency.

STAFF ASSUMED PLUME ABATED DESIGN MODELING

Considering the frequent large plumes predicted for the proposed unabated cooling tower and HRSG designs, staff has modeled potential plume abated designs for consideration.

Staff performed this modeling analysis using the Tracy/Brentwood meteorological data set. After a comparison of the Stockton data set with the Tracy/Brentwood data set and other area data sets it was found that the single year Stockton data set had significantly lower average and median relative humidities, which would likely underestimate plume frequency and plume dimensions. Therefore, while staff did provide modeling results using both data sets, staff considers the Tracy/Brentwood meteorological data set to be more representative of site conditions.

Abated Cooling Tower Visible Plume Modeling Analysis

For comparison with the proposed project designs the following minimum plume abated designs have been assumed by staff and modeled for the cooling tower and HRSG:

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.

Table 14 provides the abated cooling tower plume frequency modeling results.

Table 14
Staff Predicted Hours with Abated Cooling Tower Steam Plumes
Tracy/Brentwood 1997 to 1999 Meteorological Data

		Abated Cooling Tower	
	Available (hr)	Plume (hr)	Percent
All Hours	26,280	2,027	7.71%
Daylight Hours	13,374	582	4.35%
*Seasonal Daylight Hours	6,000	582	9.70%

* Seasonal conditions occur from November through April.

It should be noted that 524 of the 582 daylight hours (90%) that are predicted to have a plume 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 that are impacted by visual water vapor plumes. Therefore, staff expects that the actual operating plume frequency with the staff assumed abated cooling tower design would be well below the 10% seasonal daylight high constrast hour impact study threshold trigger value.

Abated HRSG Visible Plume Modeling Analysis

For comparison with the proposed project designs the following minimum plume abated designs have been assumed and modeled for the cooling tower and HRSG:

> HRSG with economizer bypass that would 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 project specific HRSG abatement information (CEC 2001i, page 5; EAEC 2001z, pages 1-3), so staff was forced to use the Russell City abatement design as a starting point in the HRSG abatement discussion for this project. Additionally, staff received revised HRSG exhaust temperature information and revised HRSG and cooling tower modeling analyses from the Applicant in November. This new information, and the project specific HRSG abatement design questions and considerations, will be addressed in the Final Staff Assessment. Staff has serious concerns about the visual impacts that would occur as a result of the unabated water vapor plumes predicted for this project, and we hope that the Applicant will work with us in a good faith effort to address our concerns and answer our questions regarding potential plume abatement designs.

Table 15 provides the abated HRSG plume frequency modeling results.

Table 15
Staff Predicted Hours with Abated HRSG Steam Plumes
Tracy/Brentwood 1997 to 1999 Meteorological Data

		Abated HRSG Worst Case	
	Available (hr)	**Plume (hr)**	**Percent**
All Hours	26,280	4,147	15.78%
Daylight	13,374	1,124	8.40%
Seasonal Daylight*	6,000	1,102	18.37%
		Abated HRSG – Duct Firing	
	Available (hr)	**Plume (hr)**	**Percent**
All Hours	26,280	1,609	6.12%
Daylight	13,374	492	3.68%
Seasonal Daylight*	6,000	492	8.20%
		Abated HRSG – No Duct Firing and No Power Augmentation	
	Available (hr)	**Plume (hr)**	**Percent**
All Hours	26,280	315	1.20%
Daylight	13,374	100	0.75%
Seasonal Daylight*	6,000	100	1.67%

* Seasonal conditions occur from November through April.
Worst case for plume is operating with duct firing and power augmentation on.

It should be noted that 805 of the 1,102 seasonal daylight hours (77%) that are predicted to have a plume during worst case operation have ambient relative humidities at or above 95%; therefore, it is assumed that most of these hours would be fog or rain hours that are not considered hours that are impacted by 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, before 10 am, where a plume is most frequently predicated to occur. Therefore, staff expects that the actual operating plume frequency with the staff assumed abated HRSG design would be well below the 10% seasonal daylight high contrast hour impact study threshold trigger value.

APPLICANT'S MODELING RESULTS REVIEW

The Applicant believes that staff's cooling tower and HRSG plume dimensions are overestimated, while staff believes that the Applicant's modeling approach has underestimated the cooling tower and HRSG plume dimensions. In general, the Applicant's plume frequency results agree closely with staff's modeling results and the modeled plume frequencies have not been at issue. Staff and the Applicant are reviewing each other's model source code to determine if there are any programming error's that may be partially to blame for the discrepancies in the plume dimension results.

Additionally, in their modeling assessment the Applicant used a 1976 Stockton meteorological data set which, as noted earlier in this assessment, does not provide a good meteorological data proxy for the EAEC project site. The Applicant's use of the

Stockton meteorological file causes their analysis to underestimate the project's cooling tower and HRSGs plume frequencies and plume dimensions.

A more detailed discussion of the modeling result issues for the cooling tower and HRSG are noted below.

COOLING TOWER COMPARISON

The Applicant, in their revised modeling analysis (EAEC 2002zz), used a model and modeling techniques that in many ways are similar to staff's CSVP model and modeling techniques. The difference between the way staff and the Applicant modeled the plumes has to do with the way in which the CSVP model was used. For the CSVP modeling runs, staff grouped the 19 cells into a single stack of equivalent diameter; while the Applicant did not attempt to group the cooling tower cells in any fashion, they modeled a single cooling tower cell at a time, without identifying plume interaction between the adjacent cells. The Applicant's modeling method only models $1/19^{th}$ of the entire exhaust volume (i.e. water emissions) from the cooling tower, which will cause the plume size from the 19-cell cooling tower to be severely underestimated. Therefore, the Applicant's current analysis cannot be used to describe the plume dimensions for the 19-cell cooling tower and their plume dimension modeling results cannot be directly compared to the results from staff's modeling analysis.

HRSG COMPARISON

In general, the Applicant's results indicate plumes that have lower lengths and heights than staff's estimates, but often with much larger plume widths. Staff is concerned that these large plume widths, which seem to be much larger than should be found using conventional rural land use classification calculations, indicate a potentially major problem with the Applicant's modeling program.

REFERENCES

CEC/Walters (California Energy Commission/William Walters) 2002i. East Altamont Energy Center Cooling Tower and HRSG Exhaust Visible Plume Analysis. Docketed January 23, 2002.

Dobney (Don Dobney) 2001. Record of conversation between William Walters, Aspen Environmental Group and Don Dobney, Marley Cooling Tower, April 2001.

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) 2001n. Data Request Response Set #1. Dated July 9, 2001 and docketed July 10, 2001.

EAEC (East Altamont Energy Center) 2001p. Responses to Data Request Set 2. Dated and docketed August 17, 2001.

EAEC (East Altamont Energy Center) 2001z (Wheatland) Applicant's Notice of Objection and Inability to Respond to Certain CEC Staff Data Requests (Set 3). Dated and docketed October 5, 2001.

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EAEC (East Altamont Energy Center) 2001gg. Data Response Set 2H. Dated and docketed October 31, 2001.

EAEC (East Altamont Energy Center) 2002zz. Revised Visible Water Vapor Plume Analysis, Response to CEC Preliminary Staff Analysis, & Assessment of Visual Plume Impacts. Dated 4/3/02 and docketed 4/3/02.

VISIBLE PLUMES – IMPACT ANALYSIS

Testimony of Dale Edwards

SUMMARY

Energy Commission staff analyzed the potential visual impacts of the proposed East Altamont Energy Center (EAEC) plumes. The proposed project's heat recovery steam generator (HRSG) stack and cooling tower water vapor plumes are predicted to occur at a frequency of 11.8 and 16.5 percent (respectively) of the clear weather seasonal daylight, no rain, no fog (SDNRNF) hours. These occurrences exceed staff's ten-percent frequency threshold, thereby requiring that an impact analysis be done. Staff's analysis has concluded that these plumes will cause adverse but less than significant visual impacts to close-in and more distant viewers.

INTRODUCTION

This analysis focuses on whether water vapor plumes from the proposed East Altamont Energy Center (EAEC) would cause significant adverse visual impacts.

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's plumes that may have the potential for significant visual impacts;

Assessment of the visual setting of the proposed power plant site;

Evaluation of the visual impacts of the proposed project's plumes 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 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?

Evaluation Process

The proposed project's plumes would be visible from a number of areas in the project region. Energy Commission staff evaluated the visual impact of the plumes from two key observation points (KOP) along Byron Bethany Road, which represent the view from areas in general at those distances (see the description of KOPs in the Setting section of this analysis). For each KOP, staff considered the existing visual setting and the visual changes that the project's plumes would cause to determine impact significance. Existing condition photographs and plume photo-simulations from each KOP are included in this analysis.

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 Expectation

Viewer expectation is a measurement of the level of viewer interest regarding the visual resources in an area. 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 expectation as a consequence of the quality of the view. Existing landscape character may temper viewer expectation on some State and locally designated scenic highways and corridors, and on other highways and roads. Commercial uses, including business parks, typically have low-to-moderate viewer expectation, 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. Industrial uses typically have the lowest viewer expectation 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. 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 visual sensitivity is a function of visual quality, viewer expectation, and viewer exposure and can range from low to high.

To assess the visual changes that project plumes would cause, staff considered primarily the dominance that the plumes would have to the viewer, but also contrast and view disruption.

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.

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.

View Disruption

View disruption includes view blockage, which considers the extent to which any previously visible landscape features are blocked from view by the project, and also the breaking up of a view of large landforms such as mountain ranges. 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, pp. 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 (Caltrans 2002). However, at this time, it has not been designated as a State Scenic Highway.

LOCAL

The proposed project is located in an unincorporated area of Alameda County. Therefore, it would be subject to any local laws, ordinances, regulations, and standards

(LORS) pertaining to the protection and maintenance of visual resources in Alameda County.

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. The relevant local LORS and an assessment of the project's LORS consistency are presented in a later section of this analysis.

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, 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 and associated towers converging on the 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, pp. 8.11-3 & 4).

PROJECT PLUME 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's plumes would be limited to adjacent and nearby roadways (Byron Bethany, Mountain House, Kelso, and Lindeman Roads) and residences. Viewers would typically be motorists traveling 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. This road carries the most travelers in the immediate project vicinity, and a length of approximately one-mile near the proposed project site has been designated by Alameda County as a scenic route. Mountain House Road is also an Alameda County-designated scenic route.

The unabated plumes from the HRSG stacks and cooling tower (based on a 10% frequency of occurrence using Sacramento 1990 to 1993 meteorological data for seasonal daylight no rain no fog hours from November through April) would reach heights of approximately 425 feet (for the HRSG) and 591 feet (for the cooling tower) during clear conditions and extend downwind approximately 387 feet for the HRSG and 1,397 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 on the south, the Coast Range to the west, and Clifton Court and Howard Roads on the North. Views of the plumes would also be available from Mount Diablo to the northwest and Brushy Peak to the west/northwest. However, because of the approximate 20-mile distance to Mount Diablo, visibility would be low. For Brushy Peak, at a distance of approximately eight miles, visibility would be moderate.

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 water and electric utility infrastructure facilities have been sited, creating a scene that is a mosaic of the rural and technological features. 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 the large Tracy Substation, from which a number of electric transmission lines and associated steel lattice transmission towers radiate out across the valley floor, several of which pass close to the project site.

In the area within two miles of the proposed project site, there are four residences with potential views of the project. The residences 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. These residences are built immediately adjacent to the Old River, are oriented toward the water, and do not have views of the project site. Mountain House School, which serves approximately 60 students, is an Alameda County public school located approximately one mile south of the project site along Mountain House Road.

KEY OBSERVATION POINTS

Staff evaluated the visual setting and the proposed project's plumes from two KOPs: (1) Byron Bethany Road at the intersection with Lindeman Road (approximately 0.75 mile southeast of the project site near the access road to the Livermore Yacht Club), and (2) Byron Bethany Road, approximately 2.0 miles southeast of the project site. These KOPs, one near and one far, provide views of the plumes crossing the field of view at nearly a right angle. Due to the low number of residents in the area and low traffic volumes on other area roadways, all but the two Byron Bethany Road KOPs considered in the Visual Resources chapter were discarded for the analysis of visual plumes. A discussion of the visual setting for each KOP is presented in the following paragraphs.

KOP 1 – Byron Bethany Road at Lindeman Road

KOP 1 represents the view to the northwest from the intersection of Byron Bethany and Lindeman Roads (see **Visible Plumes Figure 1**). This viewpoint is approximately 0.75-mile southeast of the proposed site. From this location, the proposed project's plumes would be within the "cone of vision" (45 degrees either side of the direction of travel) of northwest bound motorists on Byron Bethany Road. Byron Bethany Road 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, p. 8.11-8). There are no residences near this KOP; however, there are a few individual scattered residences approximately one mile from the project site. Each of these residences face away from the project site and are surrounded by trees and other buildings that block direct views toward the project site.

Visual Quality

From this viewpoint, the most prominent features in the existing landscape are the roadway with its associated electric distribution lines and poles; the electric transmission lines and towers that appear to become larger to travelers proceeding northwest; the electric transmission structures converging on the Tracy Substation; the Tracy Substation with its complex of vertical forms and lines; the rolling to angular forms and curvilinear lines of the Coast Range including Brushy Peak and Mount Diablo (which is a visible regional landmark) as well as the flat, open agricultural fields that occupy the foreground and middleground. Wind turbines on the hills in the background are visible in the landscape, but they are not dominant landscape features. Although the overall landscape character is rural agricultural, as northwest bound travelers on Byron Bethany Road proceed past KOP 1, the substantial industrial components of the area become increasingly prominent in the viewIn addition, Byron Bethany Road is a well-traveled two-lane highway with high traffic volume most of the day, a substantial portion of which are trucks. Considering all of these elements, visual quality is moderate.

Viewer Expectation

Byron Bethany Road primarily serves local traffic. Motorists on this road traveling northwest see conditions changing from a middleground view largely composed of a rural agricultural landscape, to a foreground with a prominent energy transmission infrastructure presence, and a background with substantial wind turbine development on the east face of the Coast Range foothills. Alameda County has designated the one-mile length of Byron Bethany Road nearest the proposed EAEC site, which is the only part of Byron Bethany Road that is in Alameda County, as a scenic highway. Neither Contra Costa County, immediately northwest of the project site, nor San Joaquin County, just southeast of the site, have designated Byron Bethany Road as scenic. Considering the moderate visual quality experienced by travelers and residents, viewer expectation is moderate.

Viewer Exposure

Plume visibility would be moderate-to-high for motorists traveling northwest at KOP 1 because the view is open and unobstructed at this middleground-to-foreground viewing distance of approximately 0.75 mile. The number of viewers is low-to-moderate, because plumes will only occur for a couple hours per day during the cooler seasons of the year and, although the traffic count for Byron Bethany Road is 13,820 average per day, approximately 2,500 vehicles per day (about 18 percent) would be expected to pass the proposed power plant during plume formation. This estimated number of vehicles is conservatively high because it considers both directions of traffic, and staff's analysis from this KOP is intended to be for travelers to the northwest only. The duration of view (the amount of time the traveler would view the plume when not paying attention to driving) is moderate. Overall viewer exposure for motorists would be moderate.

Plume visibility would be low for residents within the area represented by KOP 1 (within a one-mile radius of the proposed project site) because they are surrounded by trees and other buildings that block direct views toward the project site. This is true for both the individual farm residences, and the approximately 30 residences within the Livermore Yacht Club area. The number of residences with views of the project site is low, and due to the low visibility, the duration of view would also be low. Therefore, overall viewer exposure for residents would be low.

Overall Visual Sensitivity

For northwest bound motorists on Byron Bethany Road, the moderate visual quality, combined with the moderate viewer expectation and moderate viewer exposure, result in an overall visual sensitivity from KOP 1 of moderate.

For residences represented by the view from KOP 1 (those within a one-mile radius of the proposed project site), overall visual sensitivity would be low-to-moderate based on the moderate visual quality and viewer expectation, and low viewer exposure.

KOP 2 – Byron Bethany Road (¼ Mile Southeast of Kelso Road)

KOP 2 (see **Visible Plumes Figure 3**) represents the view to the northwest for northwest bound travelers on Byron Bethany Road, approximately two miles southeast of the proposed project site, and for residences in the one-to-two mile radius of the project site. The traffic count is the same as for KOP 1, 13,820 average per day. There is one residence along Byron Bethany Road, about ¼ mile further to the southeast and, as described previously, there are numerous residences greater than one mile from the proposed project site. However, similar to residences for KOP 1, these more distant residences typically do not have clear open views toward the proposed project site.

Visual Quality

From this viewpoint, the most prominent features in the existing landscape are the linear form of Byron Bethany Road as it transitions from the foreground to middleground, the numerous electric distribution and transmission lines and poles, the numerous trucks and cars on the two-lane road, open agricultural fields, and two large water tanks in the foreground. Visual quality of this rural agricultural landscape is moderate, reflecting the absence of distinguishing visual characteristics and the influence of the industrial character imparted by the transmission lines and large water tanks adjacent to the roadway.

Viewer Expectation

Northwest bound motorists at KOP 2 anticipate a middleground to foreground rural agricultural landscape and the presence of numerous electric distribution lines and roadway traffic. Overall viewer expectation, considering the moderate visual quality, is moderate.

Viewer Exposure

Visibility of the plume from KOP 2 is moderate because of the two-mile distance and intervening distribution lines and poles, trees, and frequent trucks on the roadway. The number of motorists is low-to-moderate, the same as for KOP 1, and their duration of view is moderate. The resulting overall viewer exposure is moderate.

The number of residential viewers in the approximate one-to-two mile radius represented by KOP 2 is low. The visibility from these residences is low because they are surrounded by trees and other buildings that block direct views toward the project site. The duration of view for residents is low as a result of the low visibility toward the project site. The resulting overall viewer exposure is low.

Overall Visual Sensitivity

For motorists on Byron Bethany Road at this two-mile distance, the moderate visual quality and moderate viewer expectation and exposure result in an overall moderate visual sensitivity.

For residents at the one-to-two mile distance, the moderate visual quality and moderate viewer expectation and low exposure result in an overall low-to-moderate visual sensitivity.

VISIBLE PLUMES

<u>Vapor Plume Modeling Results</u>

The proposed project would include three 175-foot tall HRSG stacks, and a 57-foot tall, 1,030-foot long cooling tower structure consisting of 19 cells. Staff performed an independent psychrometric analysis and dispersion modeling analysis to predict the frequency and dimensions of visible plumes from the project's proposed unabated cooling tower and HRSG stacks (CEC/Walters 2002).

Staff's frequency threshold for potentially significant visible plumes is a 10 percent or greater frequency of plume formation during the times when plumes would be most visible. Staff has determined that there is the greatest potential for plumes to be visible during seasonal[1] daylight no rain/no fog (SDNRNF) clear sky hours. Using meteorological data and plant operating data, staff applies a sophisticated computer model to predict the frequency of plume formation SDNRNF clear sky hours. If plumes for a project are predicted to reach or exceed the 10% plume frequency threshold, staff performs additional plume dimension analysis.

Staff has identified SDNRNF clear hours as the meteorological conditions during which plumes have the greatest potential to cause adverse visual impacts. For this project, the available meteorological data set categorizes sky cover in 10 percent increments[2]. Staff includes in the "Clear" category a) all hours with total sky cover equal to or less than 10 percent plus b) half of the hours with total sky cover 20-100 percent that have a sky opacity equal to or less than 50 percent. The rationale for including these two components in this category is as follows: a) plumes typically contrast most with sky under clear conditions and, when total sky cover is equal to or less than 10 percent, clouds either do not exist or they make up such a small proportion of the sky that conditions appear to be virtually clear; and b) for a substantial portion of the time when total sky cover is 20-100 percent and the opacity of sky cover is relatively low (equal to or less than 50 percent), clouds do not substantially reduce contrast with plumes; staff estimates this time as approximately half of the 20-100% sky cover hours that have a sky opacity equal to or less than 50 percent..

Assuming duct firing from 10 a.m. to 8 p.m., an unabated HRSG plume is predicted to occur approximately 27 percent of SDNRNF hours, while an unabated cooling tower plume is predicted to occur approximately 40 percent of SDNRNF hours, both well in excess of the 10 percent threshold (see **Visible Plumes Table 1**). 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 a.m. and 8 p.m. 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 (CEC/Walters 2002). Alternatively, the plume frequencies would be lower if duct firing occurs less than assumed, or when turbines are not operating or not operating at full load. Since both the HRSG and cooling tower plumes are predicted to occur in excess of the 10 percent threshold, staff has conducted a detailed analysis of the visual impacts of these plumes.

[1] "Seasonal" is defined as the six consecutive months per year when the potential for plume formation is greatest. The months considered for a particular project are determined by the meteorological data used for that project. Usually the months are November through April, as is the case for this project.

[2] These are typically Hourly U.S. Weather Observations (HUSWO) data sets.

As **Visible Plumes Table 1** shows, the project is predicted to produce HRSG plumes 11.1 percent of SDNRNF hours during clear weather conditions, which exceeds the 10 percent threshold. The project is also predicted to produce cooling tower plumes 16.5 percent of SDNRNF hours during clear weather conditions, which also exceeds the 10 percent threshold.

Visible Plumes Table 1
Predicted Vapor Plumes
During Seasonal Daylight No Rain/No Fog (SDNRNF) Hours
Sacramento 1990-1993 Meteorological Data

Measurement Period	Total SDNRNF Hours	Total SDNRNF Hours with Plumes		Plumes During Clear Weather Conditions	
		Hours	Percent	Hours	Percent
HRSG	6,339	1,740	27.4%	745	11.8%
Cooling Tower	6,339	2,555	40.3%	1,048	16.5%

* Percentiles calculated by dividing the number of plume hours by the reference number of seasonal daylight no rain no fog hours (6,339).

Of the plumes in the clear weather category that have the greatest potential for adverse visual impacts, staff selects those plumes with dimensions where the measurement of primary concern (length in this case) would be as great or greater than the plumes predicted for 10 percent of SDNRNF hours. As shown in **Visible Plumes Table 2**, the 10th percentile HRSG and cooling tower plumes during SDNRNF hours, under clear weather conditions, would achieve substantial size. Under clear conditions, HRSG plumes would be approximately 187 feet in length, 285 feet in height, and 47 feet in width, while cooling tower plumes would be approximately 174 feet in length, 298 feet in height, and 124 feet in width. It should be noted that the cooling tower plume length dimension provided is the length of the plume from the tower. The tower itself is 1,030 feet long, so the tower length must be considered when assessing the total visible plume length.

Table 2
10th Percentile Visible Plume Dimensions
During Clear Seasonal Daylight No Rain/No Fog Hours
Sacramento 1990-1993 Meteorological Data

Plume Dimensions	Clear Weather Conditions
HRSG Plumes	
Length (feet)	187
Height (feet)	285
Width (feet)	47
Cooling Tower Plumes	
Length (feet)	174
Height (feet)	298
Width (feet)	124
Seasonal = November through April.	

Visual Impacts of Vapor Plumes

Due to the generally flat terrain in the vicinity of the project site, and the high frequency and large sizes of visible plumes, the plumes would cause a noticeable change in the landscape character when viewed from both near (KOP 1, approximately 0.75 mile) and more distant vantagepoints (KOP 2, approximately two miles). The vapor plumes would appear as prominent, billowing linear-to-irregular forms with irregular and changing outlines. The plumes would be unique moving forms, originating near ground level and rising vertically to diagonally across a background consisting of coastal hills and/or sky.

Visual Impacts from Nearby Viewing Locations - KOP 1

KOP 1 was selected to characterize vapor plume impacts on foreground to middleground viewing locations (up to two miles away). **Visible Plumes Figure 1 i**s a photograph of the existing view to travelers along Byron Bethany Road near the intersection with Lindeman Road. **Visible Plumes Figure 2** is a simulation of the minimum size of project plumes on clear days as viewed from KOP 1. As can be seen in the simulation, the plumes would be prominently visible to travelers on Byron Bethany Road as the plumes drift almost perpendicular to the direction of travel.

CONTRAST. Under clear conditions when viewed from nearby viewing locations such as KOP 1, the white vapor plumes would have high color contrast with the background blue sky and earthtone colors of the Coast Range hills to the west and north. The vertical and diagonal irregular and changing form of the plumes, substantial plume mass, and plume motion would distinguish the plumes from the broad, horizontal landforms; the generally uniform appearance of sky; and built landscape features. The resulting visual contrast on clear days would be high.

DOMINANCE. During clear conditions, the plumes would be spatially prominent and dominate other built structures and natural landscape features. Therefore, overall project dominance under clear conditions would be dominant.

VIEW DISRUPTION. Under clear conditions, project plumes would block from view portions of sky and portions of the Coast Range hills from the southeast to northwest including Brushy Peak and Mount Diablo. The resulting view disruption under clear conditions would be moderate.

OVERALL VISUAL CHANGE. When viewed from KOP 1 (and other similar vantagepoints in the project area), the values for visual contrast, project dominance, and view disruption taken together constitute a moderate-to-high degree of visual change under clear conditions.

As previously discussed, the overall visual sensitivity for KOP 1 is moderate for motorists, and low-to-moderate for residents. When the anticipated project plumes are considered within the context of the moderate and low-to-moderate visual sensitivity of the existing landscape and viewing characteristics, the moderate-to-high degree of visual change under clear conditions would cause adverse but less than significant visual impacts.

Visual Impacts from More Distant Viewing Locations – KOP 2

Project plumes and their resulting visual impacts would also be apparent from more distant regional vantagepoints (approximately two miles and greater), often with panoramic views across the valley floor to the Coast Range hills to the west and north. From these more distant views, features appear smaller in the broad, open landscape. KOP 2 was selected to characterize vapor plume impacts on background viewing locations. **Visible Plumes Figure 3** is a photograph of the existing view for travelers northwest bound on Byron Bethany Road approximately two miles from the proposed project site. **Visible Plumes Figure 4** is a simulation of project plumes on clear days as viewed from KOP 2.

CONTRAST. Under clear conditions, the white color of the plume would exhibit a high degree of color contrast with the darker blue background of the sky and earthtones of the Coast Range hills. Also, the well-defined diagonal form of the plumes would cause the plumes to stand out from the broad, low-horizontal natural landforms of the valley floor and Coast Range hills and the generally uniform appearance of clear sky. The resulting visual contrast under clear conditions would be high.

DOMINANCE. As represented by KOP 2, under clear conditions the plumes would appear prominent above the low horizon line established by the landforms of the valley floor and Coast Range hills. From those vantagepoints where the Coast Range hills are often visible in the background, the brighter color of the plumes would cause them to stand out from the more subdued earthtones of the hills. As a result, under clear conditions, the plume would be co-dominant in relation to the broad landforms and non-distinct expanse of blue sky.

VIEW DISRUPTION. Under clear conditions from KOP 2 and similar distant locations (two miles and greater), compared to close-in vantagepoints, project plumes would block from view a smaller portion of sky and a smaller portion of Coast Range hills. The resulting view disruption would be low.

OVERALL VISUAL CHANGE. From regional vantagepoints, the values for visual contrast, project dominance, and view disruption, taken together, constitute a moderate degree of visual change.

As previously discussed, the overall visual sensitivity from the more regional vantagepoint is moderate for motorists and low-to-moderate for residents. Combined with the moderate degree of visual change experienced from KOP 2, the project plumes would cause an adverse but less than significant visual impact.

Consideration of Impacts in Relation to CEQA Significance Criteria

This analysis considered the potential impacts of the proposed project vapor plumes 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 Mount Diablo (approximately 20 miles to the northwest), and to a much lesser degree, during the time periods that plumes would be visible, from Brushy Peak (approximately eight miles to the west/northwest). Due to the substantial viewing distance from Mount Diablo, the proposed project's plumes would not be prominent features in the landscape and would not cause significant visual impacts. From Brushy Peak, project plumes would be more prominent, but viewers would also see the numerous intervening wind turbines and, due to dirt road and trail access, most viewers would not visit Brushy Peak during the rainy season. In addition, the intermittent nature of plumes, varying form and opacity, contribute to lessening their visual impact. Overall, the proposed project's plumes would result in an adverse, but not significant visual impact from these scenic vista locations.

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 project's plumes are located within the viewsheds of two Alameda 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 plumes would not result in significant visual impacts under this criterion.

3. **Would the project substantially degrade the existing visual character or quality of the site and its surroundings?**

The proposed project's unabated vapor plumes would be prominent but intermittent features when seen from local viewing locations during clear weather conditions, however as discussed in this analysis, impacts on viewers (both vehicular and residential) would be less than significant.

4. **Would the project create a new source of substantial light or glare that would adversely affect daytime or nighttime views in the area?**

This criterion is not applicable to the proposed project's plumes.

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 the Mountain

House new community, which is to be developed over the next 20 to 40 years. The Mountain House community 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's plumes 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.

The proposed project's plumes, which would be visible only intermittently for a generally short period of the day during approximately half the year (the coolest months), would be added to a landscape that is already heavily impacted by energy infrastructure. This includes the large and very industrial appearing Tracy Substation located on Mountain House Road across from the proposed project site, numerous transmission towers and transmission lines, numerous wind turbines plainly visible on the hills behind the project site, and the proposed EAEC itself should it be approved. The addition of intermittent, short-duration, variable size cooling tower and HRSG water vapor plumes to a setting with the substantial existing energy infrastructure, including the new power plant, would result in an adverse, but not significant cumulative visual impact.

ENVIRONMENTAL JUSTICE

Staff has reviewed Census 2000 information that shows that the population of people of color 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 low-income population within the same radius is less than fifty percent. However, there is a pocket of people of color within a one-mile radius of the project site (in the Livermore Yacht Club north of Byron Bethany Road) that staff has considered for impacts. Based on the visual analysis, staff has concluded that this population would not have views of the project site and would not experience significant visual impacts as a result of visible water vapor plumes.

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

LOCAL

Visible Plumes Table 3 provides a listing of the applicable LORS for Alameda County which pertain to the enhancement and/or maintenance of visual quality and the protection of views. Based on staff's analysis, it appears that the proposed project's plumes would be consistent with the local policies and principles referenced in **Table 3**.

Table 3
Proposed Project's Consistency with
Local LORS Applicable to Visible Plumes

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."	YES	The proposed project plumes are consistent with Policy 111. This policy is directed to shaping urban development to capitalize on views of scenic features which is not pertinent to EAEC. However, EAEC can be evaluated using a broader interpretation of Policy 111 based on the underlying goal the policy addresses – "To preserve unique visual resources and protect sensitive viewsheds." The far-distant views of Brushy Peak and Mount Diablo by passing northbound motorists on the Byron-Bethany may be briefly and partially obstructed by the proposed project, but these views are not within a "sensitive viewshed." Therefore, the project's plumes would not be inconsist with the goal.
Alameda County East County Area Plan	Policy 197 requires that the County manage development and conservation of land in East County scenic highway corridors to maintain and enhance scenic values.	YES	The proposed project is consistent with Policy 197. This policy is directed to the overall development and conservation of land to preserve and enhance views within scenic corridors, and is not intended as a prohibition of specific projects. The brief partial "blockage" of views by passing northbound motorists of distant geographic features does not diminish the goal to "preserve and enhance views within scenic corridors." Occasional vapor plumes do not interfere with views or scenic values.
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's plumes do not specifically impede the implementation of any of the referenced principles.

Table 3
Proposed Project's Consistency with
Local LORS Applicable to Visible Plumes

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.	YES	The proposed project's plumes are consistent with this policy. this policy is intended to all "normally permitted uses"; it does not refer to "historical" uses, nor is it intended to limit uses to historical uses. The proposed project and its plumes are a "normally permitted use." "Unsightly features" as used in the plan, refers to "obtrusive signs, automobile wrecking and junk yards, and similar unsightly development or use of land."
	Policy: Encourage owners of large holdings to protect and enhance areas of scenic value.	YES	The proposed project site does not contain features of scenic value.

MITIGATION

None required.

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

Based on staff's visible plume analysis, the proposed project's water vapor plumes would cause adverse but not significant visual impacts. This is true for the water vapor plumes' project specific and cumulative impacts.

Staff found the proposed project's water vapor plumes consistent with applicable laws, ordinances, regulations, and standards.

RECOMMENDATIONS

The Energy Commission should consider staff's visible plume analysis in its consideration of certification for the proposed EAEC project.

PROPOSED CONDITIONS OF CERTIFICATION

PLUME-1 The project owner shall ensure that the EAEC cooling tower is designed so that the plume frequency will not increase from the design as certified.

Verification: At least 30 days prior to ordering the cooling tower, the project owner shall provide to the CPM for review and approval the final design specifications of the cooling tower, any associated automated control systems, and related systems selected to meet the requirements of this condition as specified below, and sensors that will be used for the monitoring required by condition **PLUME-2**. The project owner shall not order the cooling tower until notified by the CPM that the design has been approved.

Exhaust Characteristics for Cooling Tower Cells
(values are per cell)

Ambient Temperature	45°F	45°F	61°F	61°F	98°F	98°F
Relative Humidity	50%	50%	51%	51%	24%	24%
HRSG Firing	Off	On	Off	On	Off	On
Stack Gas Exit Temperature	61.4°F	72.7°F	70.3°F	79.6°F	82.9°F	89.1°F
Stack Diameter	10.26					
Stack Gas Mass Flow Rate	7,265,005 lbs/hr	7,306,279 lbs/hr	7,297,115 lbs/hr	7,340,675 lbs/hr	7,361,817 lbs/hr	7,402,715 lbs/hr

(Source: Data Responses 115, Table VIS-115-1 and 117, Table VIS-117-5 (revised 11/01/01)

The final design parameters of the cooling tower shall include: all parameters as listed in the table above, and the physical size of the cooling tower, the cell exhaust diameter, the fogging frequency curve for the cooling tower, the design L/G (liquid/gas) ratio, and the curve equation to determine the operating exhaust temperature based on the ambient temperature, relative humidity, and heat rejection load condition.

PLUME-2 The project owner shall ensure that the EAEC cooling tower is operated so that the plume frequency will not increase from the design and operating characteristics specified in condition **PLUME-1**.

<u>Verification:</u> By May 15th of each year that the cooling tower operations monitoring is required, the project owner shall provide to the CPM the cooling tower operating data for the previous November through April period. The project owner shall include with this operating data an analysis of compliance and shall provide proposed remedial actions if compliance cannot be demonstrated.

The project owner shall monitor the operation of the cooling tower to ensure that it is operated in a manner consistent with the operating variables specified in condition **PLUME-1**. The project owner shall monitor and record the hourly inlet airflow rates, the hourly operating L/G ratio, the heat rejection load, the hourly ambient temperature and relative humidity, and the corresponding hourly exhaust temperature of the cooling tower. This monitoring shall occur from November through April each year until compliance is demonstrated for three straight years, and may be required again at a later date as determined necessary by the CPM. The cooling tower data shall be provided for each cell unless the project owner can demonstrate that each cell operates identically. Compliance shall be demonstrated if the tower operates within the proposed exhaust temperature vs. operating condition curve equation (i.e., exhaust temperatures at or below the predicted values).

PLUME-3 The project owner shall ensure that the EAEC HRSGs operate so that the plume frequency will not increase from the design as certified.

<u>Verification:</u> By May 15th of each year that the HRSG operation monitoring is required, the project owner shall provide to the CPM the HRSG operating data for the previous November through April period.

The project owner shall monitor the operation of the HRSGs to ensure that they are operating as proposed. The project owner shall monitor the average hourly exhaust temperature and the turbine and duct burner natural gas firing rates; and shall estimate the hourly average moisture content of the exhaust. The hourly HRSG operations monitoring data shall be provided for each HRSG. This monitoring shall occur from November through April each year until compliance is demonstrated for three straight years, and may be required again at a later date as determined necessary by the CPM. The project owner shall include with this operating data an analysis of compliance and shall provide proposed remedial actions if compliance cannot be demonstrated. Compliance shall be demonstrated if the HRSGs exhaust temperatures are as provided in the table below (i.e. exhaust temperatures at or higher than the values provided).

Exhaust Characteristics for HRSGs
(note: data is per HRSG)

Condition	Moisture Content (% wt)	Exhaust Flow Rate (lbs/hr)	Exhaust Temperature (°F)
Full Load with duct firing and power augmentation			
Hot Ambient (98°F, 24% RH)	9.33%	3,478,379	155
Full Load with duct firing, without power augmentation			
Average Ambient (61°F, 51% RH)	7.27%	3,597,052	155
Full Load without duct firing, without power augmentation			
Cold Ambient (45°F, 50% RH)	5.37%	3,641,095	188
Average Ambient (61°F, 51% RH)	5.42%	3,509,159	185
Hot Ambient (98°F, 24% RH)	5.60%	3,172,645	189

(Source: Data Response 119, Table VIS-119-1, with the duct-fired exhaust temperature as amended on October 31, 2001.)

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EAST ALTAMONT ENERGY CENTER VISIBLE PLUME STAFF ASSESSMENT - SUMMARY OF ANALYSIS

(Does Not Include Cumulative Analysis)

VIEWPOINT		EXISTING VISUAL SETTING							VISUAL CHANGE					IMPACT SIGNIFICANCE	
Key Observation Point (KOP)	Description	Visual Quality	Viewer Expectation	Viewer Exposure				Overall Visual Sensitivity	Description of Visual Change	Visual Contrast	Project Dominance	View Disruption	Overall Visual Change	Mitigation / Conditions	Impact Significance with Mitigation
				Visibility	Number of Viewers	Duration of View	Overall Viewer Exposure								
KOP 1 **BYRON BETHANY (Approximately one-mile from project site)** **Figure 1 and 2**	View to the northwest from intersection of Byron Bethany and Lindeman Roads.	**Moderate** Foreground to middleground flat agricultural landscape with numerous electric transmission lines and substantial traffic, backdropped by rolling hills with numerous wind turbines, and more distant Brushy Peak and Mount Diablo (which is a visible regional landmark).	**Moderate** Motorists traveling northwest on Byron Bethany Road anticipate a middleground to foreground agricultural landscape and the presence of energy infrastructure and traffic, as well as unobstructed views of the hills beyond and Mount Diablo.	**Moderate to High**	**Low to Moderate**	**Moderate**	**Moderate**	**Moderate**	Addition of prominent billowing linear-to-irregular forms with changing outlines. Plume mass would appear similar to surrounding facilities at this middleground to foreground viewing distance.	**High**	**Dominant**	**Moderate**	**Moderate to High**	**None**	**Adverse but Not Significant**
KOP 2 **BYRON BETHANY ROAD (Approximately two-miles from project site)** **Figure 3 and 4**	View to the northwest along Byron Bethany Road, two miles southeast.	**Moderate** Foreground to middleground flat agricultural landscape with numerous electric transmission lines and substantial traffic in the foreground to middleground of views backdropped by rolling hills and wind turbines.	**Moderate** Motorists traveling northwest on Byron Bethany Road anticipate a foreground to middleground agricultural landscape and the presence of energy infrastructure and traffic.	**Moderate**	**Low to Moderate**	**Moderate**	**Moderate**	**Moderate**	Addition of noticeable billowing linear-to-irregular forms with changing outlines. Plume mass would appear co-dominant with other features in view at this background to middleground viewing distance.	**High**	**Co-Dominant**	**Low**	**Moderate**	**None**	**Adverse but Not Significant**

VISUAL RESOURCES

Testimony of Michael Clayton

SUMMARY OF CONCLUSIONS

Energy Commission staff analyzed both the potential visual impacts of the proposed East Altamont Energy Center (EAEC) structures and lighting and the compliance of those project features with applicable laws, ordinances, regulations, and standards (LORS). The proposed project structures would be prominently situated next to two Alameda County-designated scenic corridors in a highly visible location. Staff's conclusions are as follows:

As presently proposed, the project's structures would result in significant visual impacts. Although the applicant has proposed a landscaping plan to partially screen project structures, staff has concluded that the screening would not reduce the impacts to less than significant levels. Furthermore, because of concerns of the biology staff of the California Department of Fish and Game (CDFG) and U.S. Fish and Wildlife Service (USFWS) regarding impacts on wildlife resources in the immediate project vicinity, staff has been unable to develop an alternative landscape plan that would be both effective in screening project structures and acceptable to those agencies. Therefore, staff has concluded that the significant visual impacts resulting from project structures cannot be mitigated to less than significant levels.

The project's structures would contribute substantially to significant cumulative visual impacts.

Project lighting has the potential to cause significant visual impacts and to contribute substantially to significant cumulative visual impacts. However, proper implementation of mitigation measures proposed by the applicant and expanded by staff (Conditions **VIS-4** and **VIS-5**) would reduce project-specific lighting impacts to levels that would not be significant and would reduce project lighting's contribution to cumulative visual impacts to a less than substantial level.

The significant visual impact that would be experienced by the minority population located north of Byron Bethany Road would be similar to the impact experienced by other dispersed non-minority residences in close proximity to the project site. Therefore, the minority population would not be disproportionately impacted.

Staff finds that the proposed project structures would be inconsistent with seven applicable laws, ordinances, regulations, and standards (LORS) of Alameda County regarding visual resources and partially inconsistent with another. The Alameda County Community Development Agency has found that the project would be consistent with all of the County's applicable LORS regarding visual resources (Alameda County 2002).

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 and provides generally replicable results and logical conclusions.

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, or standards can constitute significant visual impacts. See the section on Laws, Ordinances, Regulations, and Standards.

Professional Standards

Professionals in the field of 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 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

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[1] The use of KOPs or similar view locations is common in visual resource analysis. The U.S. Bureau of Land Management (USDI BLM 1986a, 1986b, 1984) and the U.S. Forest Service (USDA Forest Service 1995) use such an approach.

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, pp. 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 (Caltrans 2002). 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. Each county's LORS apply to those portions of the project located in that particular county.

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. The Scenic Route Element of the Alameda County General Plan designates both Byron Bethany Road and Mountain House Road as scenic rural roads in the project area. 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 reverse osmosis 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. Modifications also would be made at Tracy and Westley substations. The modifications would be confined to within the existing developed facility areas.

NATURAL GAS PIPELINE

Calpine has changed its proposed natural gas pipeline route (Calpine 2002pp). The proposed underground pipeline would be approximately 1.8 miles in length, extending from PG&E's existing gas transmission line at a point approximately 0.7 miles south of Kelso Road northeast along the Delta-Mendota Canal to Kelso Road, then east past Mountain House Road, then north to the power plant site.

The gas metering station at the beginning of the route would be sited adjacent to east side of the Delta-Mendota canal, approximately 0.7 miles south of Kelso Road. Associated with the gas pipeline would be a gas metering station at the interconnection with the PG&E gas pipeline, at the location specified in the AFC for Alternative route 2e. 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.

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.

Reclaimed water, in addition to raw water, would be used when available. 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, 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, 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. In rural areas such as this, the scenic corridor within which the Scenic Route Element of the Alameda County General Plan's policies applies is defined as 1,000 feet on each side of the road (EAEC 2001a, p.8.11-26).

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, 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, 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 **Visual Resources Figure 3A** 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 **Visual Resources Figure 4A** 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 (out of the frame of **Visual Resources Figure 5A** 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, 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, 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, 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 at night to make up schedule deficiencies (EAEC 2001a, p. 2-23). In order to ensure that significant construction lighting impacts do not occur, staff recommends 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 are discussed below by KOP and presented in the Visual Analysis Summary table included as **Visual Resources Appendix VR-1**. The visual impacts of night lighting are discussed in a separate section 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

VISUAL RESOURCES 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.

VISUAL RESOURCES 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, 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 and 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 and 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 and 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 portions of the sky and valley floor (higher quality landscape features) near the horizon line from view. 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 and 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 and 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 (e.g., 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 (e.g., sky and Coast Range hills).

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. The various components of the natural gas metering station (several aboveground pipeline segments, valves, and a small structure for controls) would appear industrial in character. However, the closest publicly accessible areas from which the gas metering station would be potentially visible are along Mountain House and Kelso roads, 0.7 miles and farther from the metering station site. The eastern berm of the Delta-Mendota Canal adjacent to the site would provide substantial potential for visual absorption into the backdrop. The metering station would have minimal public visual access and would not be prominent in views from any nearby roads, including Mountain House Road. The size of the equipment would be relatively small. For these reasons, if colors that blend with the backdrop are used, the visual impact of the construction and operation of the natural gas metering station 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 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 – to the EAEC. 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.

<u>Lighting</u>

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, 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, 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 (e.g., 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.

CONSIDERATION OF IMPACTS IN RELATION TO CEQA SIGNIFICANCE CRITERIA

This analysis considered the potential impacts of the proposed project structures in relation to the four significance criteria for visual resource impacts listed in Appendix G of the CEQA Guidelines, under Aesthetics. These criteria are 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). 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 toward the project site encompass numerous intervening wind turbines that detract from scenic quality.

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.

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 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.

Mitigation of the visual impacts identified under Criteria 3 and 4 is addressed below in the Mitigation section.

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 the Mountain House new community, which is to be developed over the next 20 to 40 years as a mixed-use suburban community. The community of Mountain House would be 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 because the specific design of the portion of the community to be built in the EAEC viewshed has not been determined.

In addition, the proposed project structures would add substantially 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. For the vast majority of those who would have views of the proposed project (travelers along Mountain House Road) the proposed project structures would cause a greater contribution to cumulative visual impacts than any of the other energy infrastructure features, including the Tracy Substation. Therefore, the project structures would constitute a substantial contribution to significant cumulative visual impacts in the viewshed. 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 persons residing north of Byron Bethany Road in the Livermore Yacht Club community would not have views of the project and thus 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 in regard to visual resources.

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.

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 would address removal of the power plant structures. No special conditions regarding visual resources are expected to be required to address any of the three types of closure.

COMPLIANCE WITH LORS

LOCAL

VISUAL RESOURCES 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 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 five cases of inconsistency or partial consistency, either the inconsistencies would not initially produce a significant visual impact, or full and effective implementation of staff's conditions of certification would ensure that the project complies with these LORS. In two cases of project inconsistency, the inconsistency constitutes a significant visual impact that cannot be mitigated.

VISUAL RESOURCES Table 4 Proposed Project's Consistency with Local LORS Applicable to Visual Resources			
Source	**Description of Principles, Objectives, and Policies**	**Determination of Consistency Before Mitigation/ Conditions**	**Basis for Determination**
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. If the project were located farther south on the parcel, those views would not be blocked. Therefore, the project does not maximize views of those features. 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	See above	Position of Alameda County Planning Department: YES	"The proposed project is consistent with Policy III. This policy is directed to shaping urban development to capitalize on views of scenic features which is not pertinent to EAEC. However, EAEC can be evaluated using a broader interpretation of Policy 111 based on the underlying goal the policy addresses – "To preserve unique visual resources and protect sensitive viewsheds." The far-distant views of Brushy Peak and Mount Diablo by passing northbound motorists on the Byron-Bethany may be briefly and partially obstructed by the proposed project, but these views by passing motorists are not within a "sensitive viewshed". Therefore, the proposed project is not inconsistent with the goal."
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, p. 8.11-25).

VISUAL RESOURCES Table 4 Proposed Project's Consistency with Local LORS Applicable to Visual Resources			
Source	**Description of Principles, Objectives, and Policies**	**Determination of Consistency Before Mitigation/ Conditions**	**Basis for Determination**
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.
Alameda County East County Area Plan	See above	Position of Alameda County Planning Department: YES	"The proposed project is consistent with Policy 117. The proposed 230 kV line is short (0.5 mile) and located In an area where transmission structure is already a prominent feature of the landscape. As explained in the Calpine application, the 'costs of undergrounding high voltage transmission lines… are very high.' Because of the requirements for expensive transition stations at each end of an underground line and for provisions for insulating and cooling the underground conductors, building high voltage lines underground generally costs about 7 times the cost of building them overhead. Given the very marginal aesthetic benefit that undergrounding the project transmission line would produce, it was determined that it would not be economically feasible or prudent to build the line underground." We believe this determination is reasonable in the geographic contest of many high-voltage transmission lines (PG&E, Western, MID, TID)."

VISUAL RESOURCES Table 4 Proposed Project's Consistency with Local LORS Applicable to Visual Resources			
Source	**Description of Principles, Objectives, and Policies**	**Determination of Consistency Before Mitigation/ Conditions**	**Basis for Determination**
Alameda County East County Area Plan	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 Bushy 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 structures' inconsistency with this policy would constitute an adverse but not significant visual impact.
Alameda County East County Area Plan	See above	Position of Alameda County Planning Department: YES	"The proposed project is consistent with Policy 197. This policy is directed to the overall development and conservation of land to preserve and enhance views within scenic corridors, and is not intended as a prohibition of specific projects. Please refer to our comments regarding Policy 111, above. The brief, partial "blockage" of views by passing northbound motorists of distant geographic features does not diminish the goal to "preserve and enhance views within scenic corridors." (ECAP, p. 57) Similarly, occasional vapor plumes do not interfere with views or scenic values."
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.

VISUAL RESOURCES Table 4 Proposed Project's Consistency with Local LORS Applicable to Visual Resources			
Source	**Description of Principles, Objectives, and Policies**	**Determination of Consistency Before Mitigation/ Conditions**	**Basis for Determination**
Alameda County East County Area Plan	See above	Position of Alameda County Planning Department: YES	"The proposed project is consistent with Policy 264. This policy is intended to apply to undergrounding of distribution lines by new residential and commercial developments. The policy is inapplicable to this project. Please also see our comments on Policy 117, above."
Alameda County General Plan Scenic Route Element Principles	<u>Principle</u>: Provide a continuous, convenient system of scenic routes. <u>Principle</u>: Establish efficient and attractive connecting links. <u>Principle</u>: Provide for unimpeded pleasure driving. <u>Principle</u>: Coordinate scenic routes and recreation areas. <u>Principle</u>: 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
Alameda County General Plan Scenic Route Element Principles	<u>Principle</u>: 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. These project aspects would result in adverse and significant visual impacts, which would be inconsistent with this policy. Since the visual impacts resulting from project structures cannot be mitigated to levels that are not significant, the project's inconsistency with this policy would constitute a significant visual impact.
Alameda County General Plan Scenic Route Element Principles	See above	Position of Alameda County Planning Department: YES	"The proposed project is consistent with this policy. This policy is intended to allow "normally permitted uses"; it does not refer to "historical" uses, nor is it intended to limit uses to historical uses. The proposed project is a "normally permitted use". It is also incorrect to characterize the project or the vapor plumes as "unsightly features" merely because they are industrial features. "Unsightly features" as used in the plan, refers to "obtrusive signs, automobile wrecking and junk yards, and similar unsightly development or use of land."

VISUAL RESOURCES Table 4 Proposed Project's Consistency with Local LORS Applicable to Visual Resources			
Source	**Description of Principles, Objectives, and Policies**	**Determination of Consistency Before Mitigation/ Conditions**	**Basis for Determination**
Alameda County General Plan Scenic Route Element Principles	Principle: 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.
Alameda County General Plan Scenic Route Element Principles	See above	Position of Alameda County Planning Department: YES	"The proposed project is consistent with this policy. This policy states "New overhead transmission towers and lines should not be located within scenic corridors **when it is feasible to locate them elsewhere.**" In this instance, because of the location of the powerplant, and its relatively to the adjacent substation, it is not feasible to locate the transmission towers elsewhere."
Alameda County General Plan Scenic Route Element Principles	Principle: 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, p. 8.11-25).
Alameda County General Plan Scenic Route Element Principles	Principle: Use landscaping to increase scenic qualities of scenic route corridors.	NO	The proposed landscaping would not increase scenic quality compared to existing conditions and the residual visual impact would be adverse and significant. The proposed project's inconsistency with this policy would constitute a significant visual impact
Alameda County General Plan Scenic Route Element Principles	See above	Position of Alameda County Planning Department: YES	"The proposed project is consistent with this policy, because the landscaping will be "designed and maintained in scenic route corridors to provide added visual interest" and to screen views of the plant. The policy does not require landscaping to increase scenic quality compared to existing conditions."
Alameda County General Plan Scenic Route Element Principles	Principle: Landscape all properties and streets.	YES	The proposed project includes landscaping and vegetative screening.

VISUAL RESOURCES Table 4 Proposed Project's Consistency with Local LORS Applicable to Visual Resources			
Source	**Description of Principles, Objectives, and Policies**	**Determination of Consistency Before Mitigation/ Conditions**	**Basis for Determination**
Alameda County General Plan Scenic Route Element Principles	Principle: 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.
Alameda County General Plan Scenic Route Element Principles	See above	Position of Alameda County Planning Department: YES	"The proposed project site does not contain features of scenic value."
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. Policy 12: Aesthetics should be considered when reviewing development proposals.	YES 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. *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.

VISUAL RESOURCES Table 4 Proposed Project's Consistency with Local LORS Applicable to Visual Resources			
Source	**Description of Principles, Objectives, and Policies**	**Determination of Consistency Before Mitigation/ Conditions**	**Basis for Determination**
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. Policy 13: Development proposals along scenic routes shall not detract from the visual and recreational experience.	YES 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:* 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.

VISUAL RESOURCES Table 4 Proposed Project's Consistency with Local LORS Applicable to Visual Resources			
Source	**Description of Principles, Objectives, and Policies**	**Determination of Consistency Before Mitigation/ Conditions**	**Basis for Determination**
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.

VISUAL RESOURCES Table 4 Proposed Project's Consistency with Local LORS Applicable to Visual Resources			
Source	**Description of Principles, Objectives, and Policies**	**Determination of Consistency Before Mitigation/ Conditions**	**Basis for Determination**
Contra Costa County General Plan, Transportation & Circulation Element, Scenic Routes	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.
	Policy 5-43: Aesthetic design flexibility of development projects within a scenic corridor shall be encouraged.	YES	See Policy 5-34 above.

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.
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 variously of rows and informal groupings of deciduous and evergreen trees and shrubs along the site perimeter (see **VISUAL RESOURCES Figure 10**). Specifically, the landscape plan would include:

   Along the eastern side and much of the northern and southern sides: A staggered double row of lombardy poplars and informal groupings of river she oaks.

   Along the western portion of the northern and southern sides: A double row of California pepper trees and informal groupings of western redbud and toyon.

Along the western side: A dense row of Pacific wax myrtle and informal groupings of evergreen native shrubs consisting of manzanita, coffeeberry, and sugar bush.

4. ing the switchyard on the southern side (in addition to [a] above): Pacific wax myrtle.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 to the extent feasible.

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). Based on consultations with staff of the California Department of Fish and Game and U.S. Fish & Wildlife Service, the type of landscaping necessary to effectively screen the project structures would conflict with the goals for wildlife habitat management and would therefore, not be acceptable.

Therefore, staff has concluded that the significant visual impacts resulting from project structures cannot be mitigated to less than significant levels.

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 to mitigate project night lighting impacts as follows:

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 Conditions of Certification **VIS-4** and **VIS-5**).

Full and effective implementation of Conditions of Certification **VIS-4** and **VIS-5** would minimize lighting and keep lighting impacts to less than significant levels.

Mitigation of Impacts in Relation to CEQA Significance Criteria

The project's structures would substantially degrade the existing character and quality of the site and its surroundings (Criterion 3). Staff has concluded that mitigation is not available to reduce the significant visual impacts of project structures under Criterion 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 Criterion 4. However, the exterior lighting control measures proposed by the applicant and expanded by staff in Conditions of Certification **VIS-4** and **VIS-5** would ensure that lighting impacts would be less than significant with regard to Criterion 4.

Mitigation of Cumulative Impacts

Effective implementation of staff's proposed conditions Vis-4 and VIS-5 would keep the contribution of the project's lighting to significant cumulative visual impacts to a less than substantial level.

RESPONSE TO COMMENTS

Alameda County 2001a, re: Data Request 61:

Alameda County expressed its preference for the use of trees and shrubs rather than berms for visual screening of the site, biological effects notwithstanding. The County suggested the use of relatively small trees near the road to reduce the potential for biological impacts.

Response: Visual resources staff considered the use of relatively small trees near the roads surrounding the proposed site. However, staff of the California Department of Fish and Game and the U.S. Fish and Wildlife Service stated that this mitigation option was unacceptable.

Alameda County 2001b, re: Visual Impacts *The County's letter states that "The following three recommended conditions reflect the results of a cooperative effort between the County with the applicant to achieve thorough mitigation for perceived impacts to farmland and visual character of the area." For visual impact, the County recommends Condition 3:*

"Applicant shall design and submit for review by the County Planning Director a program for visual attenuation of views of the East Altamont Energy Center. The program should include sensitive landscaping with trees, shrubs and other appropriate vegetation for screening, low berms or hillocks where necessary, a paint scheme that helps the plant blend in with the background of hills or sky, depending upon the vantage point, and night lighting that illuminates only the site and necessary equipment, without light trespass offsite and generally without escape of light from the immediate area of the plant and operations above the horizontal. Trees and plantings shall be the preferred method of screening and shall be chosen and installation designed so as to minimize the loss of farmland; species should be chosen and installation designed so as to minimize the loss of farmland; species should be chosen for their attractiveness, suitable water and climate requirements, and where necessary, to avoid creation of perches for raptors, taking into account tree heights and stiffness of branches. Berms and hillocks should be used sparingly and only where trees would not be practical or would result in another major impact type, such as biological. Paint colors should be chosen for their ability to blend with the natural surroundings of grassy hillsides and bright sky, and should be applied to the plant with attention given to backgrounds as seen from various angles. Wherever possible , lighting practice shall employ full cutoff light fixtures and lighting shall be installed using motion sensitive circuitry to provide lighting when it is needed and for security. Examples and/or of trees, light fixtures and paint samples should be submitted with the report.

The report shall be submitted prior to issuance of building and grading permits for the project, and implemented features shall be subject to inspection and verification upon completion, and the inspector may take steps as necessary to ensure compliance with the approved program."

<u>Response</u>: Staff's proposed conditions of certification address the County's concerns regarding color (**VIS-2**), landscaping (**VIS-3**), and lighting (**VIS-5**)

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?*

<u>Response</u>: The impact portion of the Visual Resources section of the FSA concludes that significant adverse visual impacts would result from the proposed project. Staff has also concluded that the only landscape plan acceptable to the California Department of Fish and Game and the U.S. Fish and Wildlife Service would be insufficient to mitigate the significant visual impacts caused by project

structures. Therefore, the project as proposed would result in significant visual impacts that cannot be mitigated.

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, staff's proposed 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-15: *At a 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: The Visual Resources analysis identified potential inconsistencies with four principles of the County's General Plan Scenic Route Element pertaining to the protection of views from scenic route corridors. However, Alameda County has determined that the proposed project would be consistent with the Scenic Route Element.

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.*

Response: The impact portion of the Visual Resources section of the PSA concludes that significant adverse visual impacts would result from the proposed project. Staff has also concluded that the only landscape plan acceptable to the California Department of Fish and Game and the U.S. Fish and Wildlife Service would be insufficient to mitigate the significant visual impacts caused by project structures. Therefore, the project as proposed would result in significant visual impacts that cannot be mitigated.

G&MG-5: *I also have a concern about the bright lighting that will be at night on the country roads. When the Muso Olive plant added lighting to their plant off of Schulte and Mt. House Parkway, if you were driving south on Mt. House Parkway, at times the driver was blinded by these (I believe they were described as Cal Trans Lights) lights. Many times I was blinded by these lights and couldn't see the road. This also added brightness from the Safeway and Costco plants. There must have been complaints to the plant as they were adjusted, and they are not as blinding as before although they are still bright. I think the distance was about a mile or so.*

Response: The proposed project has the potential to be very brightly lighted at night. However, staff's proposed conditions of certification require the applicant to control lighting in such a way that night lighting does not cause a significant visual impact or public safety hazard.

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

The project's structures would result in significant visual impacts. Although the applicant has proposed a landscaping plan to partially screen project structures, staff has concluded that the screening would not reduce the impacts to less than significant levels. Furthermore, because of concerns of the biology staff of the California Department of Fish and Game (CDFG) and U.S. Fish and Wildlife Service (USFWS) regarding impacts on wildlife resources in the immediate project vicinity, staff has been unable to develop an alternative landscape plan that would be both effective in screening project structures and acceptable to those agencies. Therefore, staff has concluded that the significant visual impacts resulting from project structures cannot be mitigated to less than significant levels

Proper implementation of mitigation measures proposed by the applicant and expanded by staff (Conditions **VIS-4** and **VIS-5**) would reduce lighting impacts to levels that would not be significant.

Project lighting would contribute to significant cumulative visual impacts from lighting. However, proper implementation of staff's proposed Conditions **VIS-4** and **VIS-5** would reduce the contribution of the project's lighting to cumulative lighting impacts to a less than substantial level.

The significant visual impact that would be experienced by the minority population located north of Byron Bethany Road would be similar to the impact experienced by other dispersed non-minority residences in close proximity to the project site. Therefore, the minority population would not be disproportionately impacted.

Staff finds that the proposed project structures would be inconsistent with seven applicable laws, ordinances, regulations, and standards (LORS) of Alameda County regarding visual resources and partially inconsistent with another. The Alameda County Community Development Agency has found that the project would be consistent with all of the County's applicable LORS regarding visual resources (Alameda County 2002).

RECOMMENDATIONS

The Energy Commission should adopt the following conditions of certification if it approves the project.

PROPOSED CONDITIONS OF CERTIFICATION

VIS-1 To minimize the visual impacts of project construction, the project owner shall visually screen the project site as well as staging and material and equipment storage areas with temporary screening fencing. The screening for the power plant site shall be no less than12 feet tall. The screening for staging and material and equipment storage areas shall be no less than 8 feet tall unless material or equipment will be more than 8 feet tall, in which case the screening shall be no less than 12 feet tall. Fencing shall be of an appropriate design, opacity, and color for each specific location, as determined by the CPM. All evidence of construction activities, including ground disturbance due to staging and storage areas, shall be removed and remediated to an original or improved condition upon completion of construction including the replacement of any vegetation or paving removed during construction.

The project owner shall submit to the CPM for review and approval a detailed screening and restoration plan the proper implementation of which will satisfy these requirements. The project owner shall install the temporary screening before the start of project construction.

Verification: At least 90 days prior to the start of site mobilization, the project owner shall submit the screening and restoration plan to the CPM for review and approval.

The project owner shall notify the CPM within seven days after installing screening at staging and material and equipment storage areas that it is ready for inspection.

The project owner shall notify the CPM within seven days after completing the surface restoration that it is ready for inspection.

VIS-2 Prior to first turbine roll, the project owner shall treat the surfaces of all project structures and buildings visible to the public such that their colors minimize visual intrusion and contrast by blending with the landscape; their surfaces do not create excessive glare; and they are consistent with local laws, ordinances, regulations, and standards. The project owner shall submit for CPM review and approval and to Alameda County for review and comment, a specific treatment plan the proper implementation of which will satisfy these requirements. The treatment plan shall include:

a) Specification, and 11” x 17” color simulations at life size scale when viewed at 18 inches, of the treatment proposed for use on project structures, including structures treated during manufacture;

b) A list of each major project structure, building, tank, transmission line tower and/or pole, and fencing specifying the color(s) and finish proposed for each (colors must be identified by name and by vendor brand or a universal designation). The transmission line structures shall have a neutral gray finish. The conductors shall be non-specular conductors and non-reflective, and the insulators shall be non-refractive;

c) Two sets of brochures and/or color chips for each proposed color;

d) Samples with dimensions of at least five inches by seven inches of each proposed treatment and color on the predominant material to which each treatment would be applied to the heat recovery steam generator (HRSG), the HRSG stacks, and the cooling tower;

e) A detailed schedule for completion of the treatment; and

f) A procedure to ensure proper treatment maintenance for the life of the project.

The project owner shall not specify to the vendors the treatment of any buildings or structures treated during manufacture, or perform the final treatment on any buildings or structures treated on site, until the project owner receives notification of approval of the treatment plan by the CPM.

Verification: The project owner shall submit its proposed treatment plan at least 90 days prior to ordering the first structures that are color treated during manufacture.

Prior to first turbine roll, the project owner shall notify the CPM that all buildings and structures 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 install landscaping to provide the maximum feasible visual screening between the power plant and public view areas. The landscaping shall include rows and informal groupings of evergreen trees and shrubs around the power plant to provide a virtually continuous visual screen. To maximize visual screening the species to be used shall be fast-growing and capable of reaching a minimum height of 50 feet at maturity, and the size of the plants shall be the optimum for achieving maximum height as soon as possible. The landscaping may include additional deciduous trees and shrubs to provide variety. The project owner shall also plant evergreen trees and/or shrubs to visually screen the above-ground ancillary facilities associated with the linear project components, except for new transmission line structures for the interconnection.

The project owner shall submit a landscaping plan to the CPM for review and approval and to Alameda County for review and comment. The plan shall include:

a) 11”x17” color photo simulations of the proposed landscaping for the power plant at 10 years after planting as it is expected to appear in both summer and winter as viewed from KOPs 1, 2, and 5;
b) a detailed list of plants to be used, specifying their rates of growth and times to maturity given their proposed size and age at planting; and
c) a diagram showing the planting locations for each species. Landscaping shall be planted continuously around the power plant except as restricted by access roads and the electric transmission interconnection lines.

The project owner shall not implement the plan until the project owner receives approval of the submittal from the CPM.

Verification: The project owner shall submit the landscaping plan prior to first turbine roll and at least 90 days prior to installing the landscaping. The planting must be completed by start of project operation.

The project owner shall notify the CPM within seven days after completing installation of the landscaping, that the landscaping is ready for inspection.

VIS-4 The project owner shall ensure that lighting for construction of the power plant is used in a manner that minimizes potential night lighting impacts, as follows:

a) All lighting shall be of minimum necessary brightness consistent with worker safety;

b) All fixed position lighting shall be shielded, hooded, and directed downward to minimize backscatter to the night sky and direct light trespass (direct lighting extending outside the boundaries of the construction area);

c) Wherever feasible and safe, lighting shall be kept off when not in use and motion detectors shall be employed; and

d) A lighting complaint resolution form (following the general format of that in **VISUAL RESOURCES Appendix VR-2**) shall be maintained by plant construction management, to record all lighting complaints received and to document the resolution of that complaint.

Verification: Within seven days after the first use of construction lighting, the project owner shall notify the CPM that the lighting is ready for inspection.

If the CPM notifies the project owner that modifications to the lighting are needed to minimize impacts, within 15 days of receiving that notification the project owner shall implement the necessary modifications and notify the CPM that the modifications have been completed.

The project owner shall report any lighting complaints and documentation of resolution in the Monthly Compliance Report.

VIS-5 The project owner shall design and install all permanent lighting such that light bulbs and reflectors are not visible from public viewing areas; lighting does not cause reflected glare; and illumination of the project, the vicinity, and the nighttime sky is minimized. To meet these requirements the project owner shall ensure that:

a) Lighting shall be designed so 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 the lighting shall be such that the luminescence or light source is shielded to minimize light trespass outside the project boundary while taking into consideration security concerns.

b) All lighting shall be of minimum necessary brightness consistent with worker safety and security concerns;

c) High illumination areas not occupied on a continuous basis (such as maintenance platforms) shall have switches or motion detectors to light the area only when occupied; and

d) Plant operations staff shall 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.

Verification: At least 60 days prior to ordering any permanent exterior lighting, the project owner shall submit to the CPM for review and approval and to Alameda County for review and comment written documentation describing the lighting control measures and fixtures, hoods, shields proposed for use. The project owner shall incorporate the CPM's comments in lighting equipment orders.

Prior to first turbine roll, the project owner shall notify the CPM that the lighting has been completed and is ready for inspection.

The project owner shall report any complaints about permanent lighting and provide documentation of resolution in the Annual Compliance Report for that year.

VIS-6 The project owner shall comply with all Alameda County requirements regarding temporary and permanent signage). The design of any signs required by safety regulations shall conform to the criteria established by those regulations.

Verification: At least 90 days prior to installing signage, the project owner shall submit s signage plan to the CPM for review and approval and to Alameda County for review and comment.

The project owner shall notify the CPM within seven days after completing installation of signage that they are ready for inspection.

VIS-7 The project owner shall place the water tanks, administration building, and other smaller structures on the western edge of the power plant site to create a transition in scale between the corridor along Mountain House Road and the plant's taller features.

Verification: At least 60 days prior to the start of construction, the project owner shall submit to the CPM for review and approval a plot plan that demonstrates compliance with the condition.

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APPENDIX VR – 1: SUMMARY OF ANALYSIS

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 Figure 1

Visual Resources Figure #s	Applicant Source Figure #s	*Title* and Additional Graphic Production Guidance
1	AFC Figures 2.1-1 And 8.11-1	*Location of Key Observation Points*. Use Figure 2.1-1 as the base and add Key Observation Points from Figure 8.11-1

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VISUAL RESOURCES Figure 2A

Visual Resources Figure #s	Applicant Source Figure #s	*Title* and Additional Graphic Production Guidance
2A	Data Response KOP 1 – Existing View	*KOP 1 – Existing view to the south from the intersection of Byron Bethany Road and Mountain House Road.*

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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 VIS-5**	**Significant**
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 VIS-5**	**Significant**
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 VIS-5**	**Significant**
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 VIS-5**	**Significant**
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 VIS-5**	**Significant**
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**

WASTE MANAGEMENT

Testimony of Obed Odoemelam, Ph.D.

INTRODUCTION

This 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 applicable laws, ordinances, regulations, and standards (LORS), and will not create any significant adverse impacts.

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, doing business as East Altamont Energy Center, LLC for the handling, storage and disposal of these wastes in the amounts estimated for the project. The handling of the project's wastewater, for which a National Pollutant Discharge Elimination System (NPDES) permit is required, is discussed in the **Soil and Water Resources** section.

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 rules regarding the following:

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 Environmental Protection Agency, or 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 40 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 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 Administration'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 above-ground 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 its October 16, 2001 and February 14, 2002 memoranda 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 regards this DTSC request as appropriate for this project site and recommends a specific condition of certification (**WASTE-1**) to ensure compliance.

IMPACTS

PROJECT SPECIFIC IMPACTS

<u>Construction Related Impacts</u>

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 Impacts

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. (EAEC 2001, page 8.13-7). The salt cakes from the project's zero-liquid discharge facility will be tested to establish the most suitable disposal option as a potentially designated waste. The designation for this waste will be specified together with the chosen disposal facility in the waste management plan for the operational phase. The implementing condition of certification is WASTE-4. 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 the 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 wastes only at facilities they identify 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.

RESPONSE TO AGENCY COMMENTS

DEPARTMENT OF TOXIC SUBSTANCES CONTROL

The DTSC requested in their October 16, 2001 and February 14, 2002 memoranda to Commission staff that the applicant's SMIP be required to include specific procedures for characterizing any such contamination with respect to constituents and concentrations, and removing the constituent chemicals before site preparation and facility construction. As noted above, staff regards this DTSC request as appropriate for this project site and recommends a specific condition of certification (**WASTE-1**) to ensure compliance.

CONCLUSIONS AND RECOMMENDATIONS

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 and will not cause a significant direct, or indirect, cumulative adverse impact.

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 provide the resume of a Registered Professional Engineer or Geologist, who shall be available for consultation during soil excavation and grading activities, to the Compliance Project Manager (CPM) for review and approval. The resume shall show experience in remedial investigation and feasibility studies.

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 site mobilization the project owner shall submit the resume to the CPM.

WASTE-2 If potentially contaminated soil is unearthed during excavation 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 construction activity 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 contact representatives of the San Francisco Regional Water Quality Control Board, the Alameda County Department of Environmental Health, and the Regional Office of the California Department of Toxic Substances Control 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. The project owner shall notify the CPM within 24 hours of any orders issued to halt construction.

WASTE-3 The project owner shall obtain a hazardous waste generator identification number from the Department of Toxic Substances Control 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 via the Monthly Compliance Report of its receipt.

WASTE-4 Upon becoming aware of any impending waste management-related enforcement action by any local, state, or federal authority, the project owner shall notify the CPM of any such action taken or proposed to be taken against the project itself, or against any waste hauler or disposal facility or treatment operator with which the owner contracts.

Verification: The project owner shall notify the CPM in writing within 10 days of becoming aware of an impending enforcement action. The CPM shall notify the project owner of any changes that will be required in the manner in which project-related wastes are managed.

WASTE-5 The project owner shall prepare a Construction Waste Management Plan and an Operation Waste Management Plan for all wastes generated during construction and operation of the facility, respectively, and shall submit both plans to the CPM for review and approval. The plans shall contain, at a minimum, the following:

A description of all waste streams, including projections of frequency, amounts generated and hazard classifications; and

Methods of managing each waste, including treatment methods and companies contracted with for treatment services, waste testing methods to assure correct classification, methods of transportation, disposal requirements and sites, and recycling and waste minimization/reduction plans.

Verification: No less than 30 days prior to the start of site mobilization, the project owner shall submit the Construction Waste Management Plan to the CPM.

The operation waste management plan shall be submitted no less than 30 days prior to the start of project operation. The project owner shall submit any required revisions within 20 days of notification by the CPM.

In the Annual Compliance Reports, the project owner shall document the actual waste management methods used during the year compared to the planned management methods.

REFERENCES

California Environmental Protection Agency and Regional Water Quality Control Boards, 1999. Wastes Allowed for Discharge at Disposal Facilities. April 24.

California Department of Toxic Substances Control, (CDTSC), October 16, 2001 Memorandum to Commission Staff on the Waste Management Section of the Application for Certification for the East Altamont Energy Center.

CDTSC, February 14, 2002 Memorandum to Commission Staff on the Waste Management Section of the Preliminary Staff Assessment (PSA) for the East Altamont Project.

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.

WATER AND SOIL RESOURCES

Testimony of
Lorraine White, John Scroggs, Jim Henneforth and John Kessler

INTRODUCTION

This section analyzes potential effects on soil and water resources that would be caused by the East Altamont Energy Center (EAEC), as proposed by East Altamont Energy Company, LLC, a subsidiary of Calpine Corporation (Calpine or Applicant). The analysis specifically focuses on the potential for the project to cause impacts in the following areas:

- Whether construction or operation would lead to accelerated wind or water erosion and sedimentation.
- Whether the project would exacerbate flood conditions in the vicinity of the project.
- Whether the project's demand for water would adversely affect surface or groundwater supplies.
- Whether project construction or operation would lead to degradation of surface or groundwater quality.
- Whether the project would 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 (CWA)

The Clean Water Act (33 U.S.C. Section 1251 et seq.) was enacted with the intent of restoring and maintaining the chemical, physical, and biological integrity of the waters of the United States. The CWA requires states to set standards to protect, maintain, and restore water quality through the regulation of point source and certain non-point source discharges to surface water. Those discharges are regulated by the National Pollutant Discharge Elimination System (NPDES). In California, NPDES permitting authority is delegated to, and administered by, the nine Regional Water Quality Control Boards (RWQCB).

Section 401 of the Clean Water Act requires that any activity that may result in a discharge into a water body must be certified by the RWQCB. This would apply to stream crossings during pipeline construction. This certification ensures that the proposed activity will not violate state and federal water quality standards.

Section 404 of the Clean Water Act authorizes the U.S. Army Corps of Engineers (ACOE) to regulate the discharge of dredged or fill material within the waters of the U.S. and adjacent wetlands. The ACOE issues individual site-specific or general (nationwide) permits for such discharges.

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. Those criteria include the identification of beneficial uses, narrative and numerical water quality standards and implementation procedures. Water quality criteria for the project area are contained in the Water Quality Control Plan for the Central Valley Region. This plan sets numerical and/or narrative water quality standards controlling the discharge of wastes to the state's waters and land. Those standards are applied to the proposed project through the Waste Discharge Requirements (WDRs) permit issued by the RWQCB.

Water Supply Permit

Under Title 22 of the California Code of Regulations, the California Department of Health Services reviews and approves any 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.

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.

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.

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.

ENVIRONMENTAL SETTING

PROJECT DESCRIPTION

Calpine proposes to build the EAEC, a 820 MW combined cycle plant augmented by 245 MW of duct firing, in Alameda County. The Applicant proposes to construct EAEC within 40 acres of a 174-acre parcel being acquired by Calpine. An additional 29 acres will be required for a temporary construction laydown area. For operation of the EAEC several new linear facilities will be required. Please refer to **Project Description** section of this document for a complete description and diagrams of the proposed project and these ancillary facilities.

As proposed, EAEC's total annual water demands are projected to be 4,616 acre-feet/year (afy) on an average annual basis (4.0 million gallons a day [mgd] average daily flow), and up to 7,000 afy on a peak annual basis (9.1 mgd peak daily flow). Average daily water requirements of 4.0 mgd are based on the plant operating at 820 MW at an ambient temperature of 61°F without duct firing or steam injection. Peak daily water requirements of 9.1 mgd are based on the plant operating at 1,065 MW at an ambient temperature of 98°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 auxiliary 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 raw fresh water or recycled water (tertiary treated) as-is without further treatment. Service water for the plant, including fire water, will be obtained from the cooling tower blowdown stream after filtration and water softening. A dedicated fire water supply will be contained in the reverse osmosis feed water storage tank sufficient for a 2-hour worse-case fire (EAEC, data request and response, Set #3, Oct. 9, 2001, Response #132). Demineralized water for makeup to the HRSG's and auxiliary boilers will be obtained from treatment of the cooling tower blowdown reject stream, utilizing distillate from the brine concentrator with additional polishing from the mixed bed demineralizer.

Domestic potable water will be generated on-site from raw water delivered by BBID using a package treatment plant unit (US Filter Water Boy pre-engineered package plant with microfiltration and UV disinfection or equivalent) (EAEC 2001g, p. 2).

Soils & Water Table 1 summarizes the use of water for EAEC operations, and the discharge of wastewater associated with the proposed EAEC.

Soils & Water Table 1
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 assumes 7 cycles of concentration.
2. Flow rates reflect conditions using 100% fresh water.
3. Denotes quantity already accounted for in other Component Streams of the water balance;

Source: (EAEC 2001a, AFC Section 8.14)

Cooling process

Cooling water (99 percent of the project's water demand) is needed to dissipate waste heat from the generating process. The plant cooling system consists of a deaerating steam surface condenser, cooling tower, and circulating water system (EAEC 2001a, AFC Section 2). 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. The water will pass over the condenser 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 tower is comprised of 19 cells or fan bays. 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. Evaporative losses cause the concentration of impurities in the recirculating water. 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. Cooling water supplies will be supplemented with HRSG blowdown and Reverse Osmosis (RO) permeate following treatment of the cooling tower blowdown. 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.

Wastewater

Originally, Calpine proposed to discharge 77,000 gpd of concentrated wastewater (brine) to two onsite 15-acre evaporation ponds. A smaller wastewater recycling pond was also proposed (EAEC 2001a, Section 8.14). This proposal was changed in Supplement B of the Application for Certification (AFC), filed October 9, 2001. Supplement B eliminated the ponds and proposed instead the use of a zero liquid discharge (ZLD) system that uses a brine concentrator and two brine crystallizers or drum-type dryers to eliminate any liquid wastes. Treated water streams throughout the process are reclaimed for various plant uses. This wastewater treatment process will result in a solid waste consisting of a salt cake, which is hauled off-site for proper disposal at an appropriately licensed landfill.

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 (EAEC 2001y, Supplement B to the AFC). For a further discussion of the solid waste disposal issues, please refer to the **Waste Management** section of this document.

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 the shallow groundwater.

SITE AND VICINITY DESCRIPTION

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 the Mountain House community, 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).

Land use in the vicinity of the EAEC is primarily agricultural situated around water supply, natural gas and power generation and transmission facilities of statewide importance. These facilities include the Western Area Power Administration (Western)

Substation, intake structures and pumping stations for 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).

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.

As seen in **Soils & Water Table 2**, 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 Rincon Clay Loam for the natural gas pipeline, fiber optic cable, and transmission line. 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 & Water Table 2
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 (RdA)	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	Slight	Very Slow	Moderatel y 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	Rincon Clay Loam (RdB)	3 – 7%	0 – 16 in.	Clay Loam	Alluvium from sedimentary rocks	Slight	Slow	Well Drained	Very Good
Fiber Optic Line	Rincon Clay Loam (RdA)	0 – 3%	0 – 16 in.	Clay Loam	Alluvium from sedimentary rocks	Slight	Slow	Well Drained	Very Good
Transmission Line	Rincon Clay Loam (RdA)	0 – 3%	0 – 16 in.	Clay Loam	Alluvium from sedimentary rocks	Slight	Slow	Well Drained	Very Good

Although erosion potential from water is slight, the area is subject to moderate winds that could contribute to erosion of loose soils during grading and excavation activities of construction (EAEC 2001a, AFC Sections 8.4 and 8.9).

SOILS AND WATER CONTAMINATION

A Phase I Environmental Site Assessment (Phase I ESA) prepared for the EAEC site identified 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 these 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 a 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. Another 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 water of higher 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 & Water Table 3
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	µg/l	6
	Manganese	µg/l	10
Other	Hardness as Ca CO3	mg/l	700
	Conductivity	µmhos/cm	4570

Note: Data from well 01S/04E-33M01, sampled on 6-6-79 (Keeter, 1980).

As can be observed in **Soils & Water Table 3**, 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, an estimated TDS concentration is on the order of 3,000 mg/l based on other constituent concentrations. As defined in the AFC and subsequent documents, the proposed project will not use groundwater for any of its water requirements.

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 annual precipitation is about 12 inches. Average monthly precipitation is as shown in **Soils & Water Table 4**. 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. 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.

Soils & Water Table 4
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

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. Surface water quality is characterized as high in the project vicinity, particularly in the southern Delta.

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 CVP and 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

To meet the water requirements of the EAEC, Calpine proposes to use a combination of fresh inland (raw) water supplied by BBID and, increasingly over time, tertiary treated recycled water from Mountain House Community Services District's (MHCSD) wastewater treatment plant.

Byron-Bethany Irrigation District (BBID)

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. 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 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 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 & Water Table 5
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).

Currently, BBID primarily supplies raw water to agricultural water users in its service area, with one current industrial user - Unimin Corporation - using water for aggregate mining and processing. The water put to beneficial use (as defined by the RWQCB) by BBID during 2000 was 31,711 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 that 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). The Applicant has not provided any quantified data of BBID's historic water savings accomplished through conservation and or agricultural customer reduction measures.

BBID's historic diversions, from 1969 to 2000, are summarized as follows:

Soils & Water Table 6
BBID's Historic Annual Diversions, 1969 – 2000

YEAR	ANNUAL QUANTITY OF WATER DIVERTED (ACRE-FEET)
1969	32,404
1970	31,487
1971	39,222
1972	47,024
1973	38,437
1974	41,378
1975	41,408
1976	55,387
1977	52,517
1978	39,503
1979	43,897
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
1997	35,368
1998	28,637
1999	33,003
2000	31,711

Note: Annual historic diversion data as supplied by BBID to DWR (CEC 2001i) & (EAEC 2002a, Data Request #135).

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. Since the publication of Staff's preliminary assessment, BBID has negotiated with DWR an agreement to define under its right the amount it can divert without causing injury to the SWP (DWR, 2002a). Although BBID and the Applicant had claimed earlier in this proceeding that BBID was entitled to divert up to 60, 000 afy, the DWR/BBID agreement caps this diversion amount at 50,000 afy at a rate not to exceed 300 cubic feet per second (cfs). As of this FSA publication, the DWR/BBID Agreement had been approved by BBID and was pending approval by DWR's management.

BBID's projected average annual fresh water demand is expected to exceed this limit of 50,000 afy within the life of the project (see **Soils & Water Table 10**). Not including the water demands of EAEC, BBID expects service area demand to be 48,541 afy in 2010, 50,615 afy in 2020 and 47,815 afy in 2030 (differences between demand in 2020 and demand in 2030 are due primarily to a reduction in agricultural use) (EAEC 2001a, Table 7-2, p. 7-3). Currently, BBID's only available resource to serve these demands is its surface water diversion. However, BBID has adopted the recommendations of its "Recycled Water Feasibility Study" to develop recycled water resources within its district for industrial development and a policy supporting the use of recycled water to meet future demands.

Recycled Water

To reduce the use of fresh water over time, the Applicant proposes to use tertiary treated (recycled) wastewater from the MHCSD wastewater treatment plant to meet a portion of its demand if it becomes available through BBID on terms and conditions acceptable to EAEC (BBID 2002e). As mentioned earlier, the Mountain House community is a residential development, currently under construction less than one mile from the proposed EAEC. Current construction of the community includes the first of twelve phases of residential development. A water treatment plant and a wastewater treatment plant are already completed. MHCSD will treat raw water it receives from BBID to potable quality before supplying it to its residents, and will treat its wastewater to Title 22 tertiary standards. Both the water treatment and wastewater treatment facilities are expected to begin providing services by December, 2002. Current RWQCB permits to MHCSD allow the tertiary treated effluent to be discharged to Old River and to farmland, with no restrictions to developing other uses for the recycled water supply.

Conservative growth projections have the Mountain House development fully built out by 2020. As the community develops, the MHCSD treatment facility will produce an increasing amount of recycled water, estimated at approximately 2,965 afy by 2010, 4,448 afy by 2015, and 5,930 afy by 2020 or earlier, with a peak daily rate of 5.4 mgd (see **Soils & Water Table 7**).

At BBID's regularly scheduled meeting of October 12, 2001, the Board of Directors adopted Resolution 2001-20 establishing a recycled water policy supporting the use of recycled water in the district under certain conditions, and establishing the district as the sole provider of such resources within its service area. In accordance with Public Utilities Code 1501 et seq., Water Recycling Act of 1991, Water Code 13575 et seq., the Water Recycling in Landscaping Act, and Government Code Section 65601, MHCSD must contract with BBID to distribute recycled water within BBID's service area. At this writing, no such contract or agreement has been reached between the two parties (MHCSD 2002b).

Originally the applicant expected that only a portion of the MHCSD tertiary treated water could be made available to the project. As provided in their feasibility study, Calpine projected total recycled water available for use by the EAEC as follows:

Soils & Water Table 7
Applicant's Projected Availability and Allocation of MHCSD Recycled Water Supply (afy)

YEAR	2000	2005	2010	2015	2020	2025	2030	2035	2040
Total Recycled Water Produced	0	1,483	2,965	4,448	5,930	5,930	5,930	5,930	5,930
MHCSD's Estimated Use	0	983	1,155	1,953	3,046	3,046	3,046	3,046	3,046
Resulting Supply to EAEC	0	500	1,810	2,495	2,884	2,884	2,884	2,884	2,884

(EAEC 2001p, Recycled Water Feasibility Study)

According to the General Manager of MHCSD, all of the recycled water produced at the treatment facility can be made available to the EAEC, but actual amounts will be subject to the rate at which the community develops (MHCSD 2002b).

ANALYSIS OF PROJECT RELATED IMPACTS

DIRECT AND INDIRECT IMPACTS

Soils

The proposed project will result in both temporary and permanent land disturbance (grading, excavation, trenching, paving, etc). The power plant site and associated laydown area(s) will disturb nearly 80 acres of prime agricultural lands and permanently remove from production the 40 acres required for the plant facilities. 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. The new transmission lines will require the placement of transmission line structures on prime agricultural land, but will not prevent current uses.

Construction "best management practices" (BMPs) will be required to control wind and water erosion and storm water drainage. Although water erosion potential is slight, the area is subject to moderate winds that could erode loose soils during grading and excavation construction activities. 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 of the linear facilities, the applicant proposes permanent BMPs, including 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 the stormwater from potential contamination (that would result if there were an accidental spill and release of hazardous materials from the storage facilities) (EAEC 2001a, AFC Sections 2.2 & 8.9; EAEC 2001p, SWPPP and EAEC 2001x, SWPPP Drawings).

If appropriate BMPs are required and implemented, no significant adverse impacts to soils are expected as a result of construction and operation of the EAEC. Staff is recommending **Condition of Certification SOILS & WATER 2** to ensure no adverse impacts occur due to erosion or offsite sedimentation.

Soils and Groundwater Contamination

As discussed earlier, the recognized conditions identified in the Phase I ESA appear to be localized effects that are the 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.

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. Due to the occurrence of shallow groundwater, the applicant proposes a mounded septic system to be constructed and operated to County requirements. Staff is recommending **Condition of Certification SOILS & WATER 4** to ensure compliance with applicable requirements and protection of groundwater. As a result of these project elements and staff's proposed Condition of Certification, no significant adverse impacts to groundwater are anticipated.

Surface Water Hydrology

No natural 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. However, 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 under dewatered conditions within the man-made canal 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 nearly intersects 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.

Storm water

Drainage at the EAEC site will be 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. In order to compare pre and post-project storm water runoff under the change in site ground conditions, runoff was calculated for 32.5 acres of the site, which represents the non-process portion of 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 in **Soils and Water Table 8**.

Soils & Water Table 8
Comparison of Pre & Post-Project Storm Water Discharge

Return Period of Storm (Years)	Rainfall for 24-hour Storm (Inches)	Pre-Project Discharge from Site (cfs –[af])	Post-Project Runoff Developed on Site (cfs)	Attenuated Post-Project Discharge from the Detention Basin (cfs)
10	2.6	12.4 [6.86]	27.0	< 12.4 cfs
25	3.1	15.2 [8.24]	32.3	< 12.4 cfs
50	3.5	17.7 [9.46]	36.9	< 12.4 cfs
100	3.9	19.9 [10.46]	40.9	12.4 cfs

Cubic feet per second (cfs); Acre feet (af)
Source: (EAEC 2001a, AFC Section 8.14 and EAEC 2001z, Tables 3.1 & 4.1)

Storm water developed over the 40 acres for the EAEC generation facilities will be managed separately between areas containing chemicals or oil-filled equipment (process areas) from areas not posing a potential for hazardous material spill (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, sized for a capacity of approximately 7.5 acre-feet. The storm water detention pond will serve to detain runoff, and attenuate the discharge of runoff to no greater than flows associated with a 10-year, 24-hour event for pre-project conditions (≤12.4 cfs). This would be true for all post-project conditions of 24-hour storms associated with 10, 25, 50 and 100-year recurrence frequencies, consistent with the criteria specified by the Alameda County Flood Control and Water Conservation District.

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. Storm water discharges would be further reduced by implementing staff's recommended recycling of storm water to the cooling tower basin as specified in **Condition of Certification SOILS & WATER 7**. 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 are administered by the Central Valley – Sacramento Office of the RWQCB. Staff is recommending **Conditions of Certification SOILS & WATER 1 and 3** to ensure compliance with the requirements of this program and proper implementation of SWPPP's for both construction and operation of the project.

Raw Water Supply

Changes in BBID's Historic Use

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.

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" or failure to put water to beneficial use for a period of several years. The courts *(Smith v. Hawkins* (1895) 110 Cal. 122) and the California Water Code (Section 1241) define this period as five years or more.

In order to assess if the EAEC will create any significant change in the historic patterns of use, staff reviewed a summary of BBID's average monthly use of water over a 32-year period between 1969 – 2000, along with projections of initial fresh water use by EAEC (see **Soils & Water Table 9**).

Soils & Water Table 9
BBID's 1969 – 2000 Historic Average Monthly Water Demands with Projected Supply to EAEC (Acre-Feet)

Month	BBID's Avg. Historic Demands	Initial Supply To EAEC (2005)	Total – BBID Demands with EAEC (2005)	% Increase from Historical Demand due to EAEC
January	163	306	469	188%
February	292	276	568	95%
March	1,268	306	1,574	24%
April	3,460	296	3,756	9%
May	6,077	306	6,383	5%
June	7,223	545	7,768	8%
July	7,305	564	7,869	8%
August	6,516	564	7,080	9%
September	3,871	545	4,416	14%
October	1,131	306	1,437	27%
November	41	296	337	721%
December	29	306	335	1,055%
Total	37,113	4,616	41,729	12%

Source: EAEC 2002a, Data Request #135

In reference to BBID's historic demands, it appears that water supply to EAEC will change BBID's existing and historical patterns of water use, particularly during the months of November – February each winter. 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, which explains why BBID's historic use during these months is so low. If BBID were to supply the EAEC with fresh water year-round, it would result in a drastic change in BBID's water deliveries for these winter months. During normal and wet hydrologic conditions, the change in BBID's season of use to higher diversions in winter could be viewed as a positive result, because generally water is available for diversion in excess of natural flows in the Delta. However, during dry hydrologic conditions, even winter flows in the Delta may not be adequate to meet all demands of existing water users and their entitlements. However, with implementation of staff's recommendations for full use of recycled water by EAEC (see below), staff believes that any concerns regarding a potential change in the season of use caused by EAEC are moot.

Sufficiency of Raw Water Supply and Impacts to Downstream Users

Title 20, California Code of Regulations, Appendix B (14)(e) (i) requires an applicant to describe the effects of the project demand on the water supply and other users of this source. In addition, Section 1742 (b) of the regulations state that "…the commission staff and all concerned environmental agencies shall review the application and assess whether the report's list of environmental impacts is complete and accurate, whether the mitigation plan is complete and effective, and whether additional or more effective mitigation measures are reasonably necessary, feasible and available."

As discussed in Staff's preliminary assessment, DWR had previously 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. DWR had expressed that its beneficial uses under the SWP, or other Delta beneficial uses including maintenance of plant life, 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. Since the Preliminary Staff Assessment was published, DWR and BBID have entered into an agreement that addresses DWR's concerns and BBID's expanding water and service area needs (DWR 2002b). As stated in this agreement, BBID will be allowed to divert no more than 50,000 afy under their existing right from the SWP facilities. BBID initially claimed an entitlement to fresh water of 60,000 afy under its Pre-1914 Appropriative Right. The agreement to limit BBID's fresh water diversion to no more than 50,000 afy appears to be more in line with BBID's historic use. Not considering the demands by EAEC, BBID's projected average annual water demand is expected to approach if not exceed the agreed limit of 50,000 afy within the life of the EAEC project.

During 2000, BBID served approximately 31,000 acre-feet to its agricultural customers, and 700 acre-feet to its industrial customer, for a total supply of 31,700 acre-feet for the year. Excluding EAEC, BBID has either committed or is planning to commit fresh water supply to new customers as shown in **Soils & Water Table 10**. BBID's projected demands show an increase in the annual quantity of water to be used in the district, primarily as the result of an increase in municipal and industrial customers.

Soils & Water Table 10
BBID's Projected Average Annual Water Demands, 2000 - 2040 (afy)
(Using the Applicant's Projected Estimates of EAEC's Fresh Water Demands & Recycled Water Availability)

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	-	4,641	9,415	9,415	9,415
Tracy Hills	-	6,000	6,000	6,000	6,000
East County Airport	-	1,100	1,200	1,200	1,300
Byron	-	500	600	700	700
Subtotal – Municipal & Industrial Use	**700**	**14,241**	**19,215**	**19,315**	**19,415**
Total – Agric. , Muni. & Indus. Use	**31,700**	**48,541**	**50,615**	**47,815**	**45,015**
Plus Average Annual Raw Water Use by EAEC* (based on 4,616 afy water demands)	**-**	**2,806**	**1,732**	**1,732**	**1,732**
BBID's Projected Demands based on EAEC Average Water Demands	**-**	**51,347**	**55,215**	**49,547**	**46,747**
Peak Annual Raw Water Use by EAEC* (based on 7,000 afy water demands)	**-**	**5,190**	**4,116**	**4,116**	**4,116**
BBID's Projected Demands based on EAEC Peak Water Demands	**-**	**53,731**	**54,731**	**51,931**	**49,131**

Source: (EAEC 2001a, AFC Section 7.1)
* Assumes some recycled water use by EAEC as proposed by Applicant in Soils & Water Table 7.
Shaded areas denote demands projected to exceed BBID's fresh water resources of 50,000 afy.

Staff has inquired as to the status of development of the two largest new customers, Mountain House and Tracy Hills. Mountain House is initiating residential construction of the first of twelve phases. The proposed Tracy Hills development has been annexed by the City of Tracy, is included in the City's approved General Plan, its EIR has been certified under CEQA, and a specific development plan has been approved by the City of Tracy. Staff also understands that BBID has annexed the approximately 2,000 acres for the proposed Tracy Hills development into its service area. BBID would supply raw water to City of Tracy for treatment and distribution to Tracy Hills.

Staff recognizes that at the time the application was submitted, BBID claimed a pre-1914 right to 60,000 afy of raw water from the Delta. As a result of the agreement between DWR and BBID, BBID may divert only 50,000 afy. Considering this change, staff believes that the applicant's determination of effects on water supplies and other users of this source is no longer accurate. Staff was recently informed by BBID that they have adjusted their projected demand downward, yet staff lacks information regarding this adjustment and believes a more conservative assessment of impacts is appropriate in this case. We, therefore, rely on the information provided to staff by the applicant and BBID earlier in this proceeding to determine EAEC's possible impact.

As requested by the applicant, staff considered impacts associated with EAEC using 100 percent raw water and no recycled water. The effect on BBID's total system demands is as shown in **Soils & Water Table 11**.

Soils & Water Table 11
BBID's Projected Average Annual Water Demands, 2000 - 2040 (afy)
(Assuming 100% Fresh Water for Supply to EAEC)

Demand Type	2000	2010	2020	2030	2040
Other BBID Agric, Muni. & Indus. Use	**31,700**	**48,541**	**50,615**	**47,815**	**45,015**
Plus Average Annual Raw Water Use by EAEC* (based on using only fresh water)		**4,616**	**4,616**	**4,616**	**4,616**
BBID's Total Projected Demands based on EAEC Average Water Demands		**53,157**	**55,231**	**52,431**	**49,631**
Peak Annual Raw Water Use by EAEC* (based on using only fresh water)		**7,000**	**7,000**	**7,000**	**7,000**
BBID's Total Projected Demands based on EAEC Peak Water Demands		**55,541**	**57,615**	**54,815**	**52,015**

Source: (EAEC 2001a, AFC Section 7.1)
Shaded areas denote demands projected to exceed BBID's fresh water resources of 50,000 afy.

Under this scenario, and assuming EAEC's average annual demands, BBID's total system demands are projected to exceed supply by about 3,157 afy in 2010, 5,231 afy in 2020 and 2,431 afy in 2030. Under a scenario where EAEC's peak annual water demands are met entirely with fresh water, BBID's total system demands are projected to exceed supply by about 5,541 afy in 2010, 7,615 afy in 2020, 4,815 afy in 2030 and 2,015 afy in 2040. When EAEC's proposed raw water demand is added to BBID's other demand projections, staff finds that there is insufficient fresh (raw) water supplies to serve all of BBID's demands as early as 2010 and thereafter for essentially the balance of the life of the project (the next 25 years) for both average and peak annual. If EAEC's proposed use of raw water is approved, staff believes that it may diminish local fresh water supplies, potentially depriving BBID's other customers of fresh water supplies or result in inadequate supply to the EAEC project itself.

This effect is in conflict with CEQA guidelines as specified under Appendix G – Environmental Checklist Form, Section XVI – Utilities and Service Systems, posing the question, "(w)ould the project: d) Have sufficient water supplies available to serve the project from existing entitlements and resources, or are new or expanded entitlements needed"? Because BBID may be overcommitted in the near future, it is likely that without maximum use of local recycled water there would not be enough water to serve EAEC and BBID's other customers. This would then result in significant adverse impacts to water supplies and to other users of this supply.

Recycled Water from MHCSD

Availability and Feasibility of Recycled Water

At the December 19, 2001 workshop, the applicant affirmed their conditional intent to use recycled water to meet a portion of its demand (at most 60 percent by 2020 and thereafter). Also at this workshop, Mountain House representatives informed staff that all of the recycled water to be produced at the MHCSD wastewater treatment facility can be made available to the project. This resource essentially could meet all the project cooling water demands by 2020 or earlier based on serving EAEC's average annual demands of 4,616 afy (see **Soils & Water Table 12**). MHCSD's willingness to make all of its recycled water available to EAEC as a first priority was affirmed in their June 20, 2002 letter to the Energy Commission (MHCSD, 2002b).

Soils & Water Table 12 provides an estimate of MHCSD recycled water that could be made available to EAEC, and the amounts of raw water that would be needed in early years to make-up the difference in EAEC demands and recycled water availability.

Soils & Water Table 12
MHCSD's Projected Recycled Water Supplies Available to EAEC
(Assuming Full Use of MHCSD Recycled Water Supply by EAEC)
Fresh and Recycled Water (Average Annual in acre-feet)

Year	2000	2005	2010	2015	2020	2025	2030	2035	2040	
MHCSD's Available Recycled Supply	0	890	2,372	3,855	5,337 (Note 2)	6,930 (Note 2)	6,930 (Note 2)	6,930 (Note 2)	6,930 (Note 2)	0
BBID Fresh Water Supply Needed to Augment Recycled Water	0	3,726	2,224	761						
Total Avg. Annual Use by EAEC	0	4,616	4,616	4,616	4,616	4,616	4,616	4,616	4,616	

Note 1: EAEC's Average Annual Demand is projected to be 4,616 acre-feet/year. Beginning in 2018 or 2019, recycled water from MHCSD is projected to exceed the average annual demand. In the event of peak years, raw water may be required, but on a limited basis, for supply augmentation and or back-up.
Note 2: The total amount projected to be available from MHCSD's Recycled Water Supply is shown as an indication of additional water available to meet EAEC peak demands in excess of its average annual demands.

As stated above, the applicant has proposed to use recycled water to meet only a portion of its overall water demand, and would rely on fresh water supplies to meet its water requirements for most of the project's life. As offered by MHCSD, there are no technical reasons that prevent EAEC from using recycled water to meet nearly 100 percent of its cooling and non-potable water demand by 2020 or earlier. Calpine's willingness to implement recycled water in any capacity is subject to it being available under terms and conditions acceptable to Calpine (BBID, 2002e). According to the "Recycled Water Feasibility Study" prepared for the BBID by CH2Mhill in July, 2001, "(t)he integration of potentially available recycled water supplies is a logical extension of the district's water services to its customers" (BBID 2002d, p. 1). BBID evaluated the feasibility of providing its customers with recycled wastewater from MHCSD WWTP and other potential recycled water sources. MHCSD is within the District, is contracted to buy water from BBID, and is interested in finding uses for its tertiary treated water so it can avoid simply discharging to Old River. In this study, BBID also considered recycled water as a potential additional water resource for EAEC.

The report briefly explores the problems associated with the use of recycled water in agriculture and the potential to damage crops due to increased salinity. It is stated in the report that use of recycled water by EAEC for cooling is feasible and with some additional treatment, could be used for process water (BBID 2002d, p. 10). The feasibility study explored recycled water use for three alternatives, namely: agricultural applications of recycled water blended with fresh to reduce salinity; direct agricultural application of recycled water; and industrial use of recycled water. After full consideration, the industrial use alternative was adopted by the BBID Board as the preferred alternative consistent with the recommendations made in the study (BBID

2002d, p. 20). The adopted alternative also notes that, "(b)y focusing the initial development on the EAEC opportunity, the district will be able to start with a single, major customer and potentially build the program in the future." Noting the region's anticipated growth in water demand, resulting in an increasing demand on Delta and other surface water resources, staff concurs with BBID that recycled water use for non-potable industrial purposes is superior to use by agriculture.

Benefits of Recycled Water

The benefits of EAEC fully utilizing MHCSD's recycled water through a delivery arrangement with BBID, and reducing EAEC's demands of BBID's fresh water is quantified in **Soils & Water Table 13**.

Soils & Water Table 13
BBID's Projected Average Annual Water Demands, 2000 - 2040 (afy)
(Resulting From EAEC's Full Utilization of MHCSD's Recycled Water)

Demand Type	2000	2010	2020	2030	2040
Other BBID Agric, Muni. & Indus. Use	31,700	48,541	50,615	47,815	45,015
Plus Average Annual Raw Water Use by EAEC* (based on 4,616 afy water demands)		2,224	0	0	0
BBID's Total Projected Raw Water Demands based on EAEC Average Water Demands		50,765	50,615	47,815	45,015
Peak Annual Raw Water Use by EAEC* (based on 7,000 afy water demands)		4,628	1,663	1,070	1,070
BBID's Total Projected Raw Water Demands based on EAEC Peak Water Demands		53,169	52,278	48,885	46,085

Source: (EAEC 2001a, AFC Section 7.1)
* Assumes some recycled water use by EAEC as proposed by MHCSD in Soils & Water Table 12.
Shaded areas denote demands projected to exceed BBID's fresh water resources of 50,000 afy.

Under this scenario assuming EAEC's average annual demands, BBID's total system demands are projected to exceed supply by about 765 afy in 2010 and 615 afy in 2020, and likely no exceedance soon thereafter 2020. It should be noted that in 2020, EAEC's demands do not contribute to, or exacerbate projections of BBID's demands being in excess of supply. Under a scenario assuming EAEC's peak annual water demands, BBID's total system demands are projected to exceed supply by about 3,169 afy in 2010 and 2,278 afy in 2020. Staff believes that if EAEC were to implement full utilization of MHCSD's recycled water supply, BBID could achieve additional conservation within its fresh water supply district and potentially develop other sources of recycled water not reflected in **Soils & Water Table 13,** in order to meet its projected demands for other users.

The project's maximum use of recycled water will result in benefits above and beyond just assuring that there will be sufficient supplies of fresh water to serve other users. It should also be recognized that the quantity of recycled water to be used by EAEC will be relatively consistent on a month to month basis, whereas alternative uses of MHCSD's recycled water by either agriculture or landscape/golf course irrigation are typically seasonal. Staff estimates that maximal use of recycled water by EAEC would result in nearly twice the amount of recycled water consumed than compared to agricultural and landscape/golf course irrigation.

Title 20, Chapter 5, Appendix B, subsection (g)(14)(C)(i) of the California Code of Regulations places the burden on the applicant to discuss all other potential sources of water, if freshwater is proposed for cooling purposes, and to explain why these other sources are not feasible. The applicant has failed to show why maximum use of the recycled water made available by MHCSD is infeasible.

Also, EAEC's use of MHCSD's recycled water maintains water quality in the Delta by avoiding or minimizing the discharge of any excess treated wastewater into Old River, which empties into the Delta. Even though the wastewater from MHCSD is tertiary treated, it is expected to be of lesser quality than Delta water. Contra Costa Water District, which draws its water supplies downstream of where the raw water is removed and the MHCSD recycled water, as currently permitted, will discharge, is concerned about indirect impacts to the Delta area from using high quality water for power plant cooling while tertiary treated wastewater is discharged to the Delta. It is their position that fewer impacts would occur to the Delta and ultimately their supply if the recycled water were used by the power plant, and not discharged to Old River, thereby leaving higher quality fresh water in the Delta (CCWD 2002a). Staff finds that if the project were to use only fresh water diverted from the Delta and reclaimed water in turn was discharged to Old River which eventually discharges to the Delta, it is possible for eventual indirect water quality impacts to occur. In turn, staff finds that use of MHCSD tertiary treated water, in lieu of raw water from the Delta, is beneficial by reducing the amount of wastewater return flows to Old River and avoiding increased fresh water diversions from the Delta. The CVRWQCB has indicated that the conservation of fresh water through EAEC's use of recycled water, because it would minimize or eliminate the discharge of wastewater originating from MHCSD to the Delta, and the EAEC's use of a ZLD System, are both measures that the Board would find favorable in that these measures would preserve Delta water quality.

Issues that Could Impede Implementation of Recycled Water Supply

Regarding recycled water use, the Applicant has indicated that the "next steps include further discussions and agreements between BBID and MHCSD, and BBID Board adoption of a recycled water plan. The Applicant is committed to using as much recycled water as BBID can provide for the project's needs" (EAEC 2001a, p. 7-4). To date, neither the applicant nor BBID have entered into any agreements or arrangements with MHCSD despite MHCSD's commitment to ensure that EAEC has all of the recycled water MHCSD can produce (MHCSD 2002b).

Staff notes that the Applicant's commitment to use recycled water is only a conditional one. Based on the MOU between the Applicant and BBID, the Applicant has qualified its commitment to implement recycled water supply based on its sole discretion of whether terms and conditions are acceptable to EAEC (BBID 2002e). Staff is concerned that no action by either BBID or Calpine has been taken to negotiate an agreement with MHCSD for this supply. Furthermore, although the Applicant included consideration of a proposed 4.6 mile pipeline in the AFC that would convey recycled water from MHCSD to the EAEC project, the applicant has failed to provide adequate evidence to staff that would ensure such a facility is ever built. Staff also notes that the schedule included in the MOU between BBID and Calpine (BBID 2002e) addresses the need to complete “water service” in accordance with the EAEC construction schedule, but does not address recycled water specifically.

As a result of staff’s determination of potential impacts and information regarding the availability of recycled water, staff recommends more aggressive mitigation to avoid or lessen these impacts to other raw water users, finding that these additional mitigation measures are reasonably necessary, feasible and available. In order to mitigate the potentially significant adverse impact on BBID’s fresh water supply, staff proposes full utilization by EAEC of recycled water produced by MHCSD as provided in **Conditions of Certification SOILS & WATER 5 - 9**. This recommendation is consistent with Water Code Section 13550 et al. Specifically, Section 13552.6 of the Water Code identifies that the use of potable domestic water for cooling towers, is a waste or unreasonable use of water if suitable reclaimed water is available and the water meets the requirements set forth in Section 13550, as determined by the SWRCB after notice and hearing. Those criteria include provisions that the quality and quantity of the reclaimed water are suitable for the use, the cost is reasonable, the use is not detrimental to public health, and will not impact downstream users or biological resources. Section 13552.8 further states that any public agency may require the use of reclaimed water in cooling towers if reclaimed water is available, meets the requirements set forth in Section 13550 as determined by the SWRCB after notice and hearing, that there will be no adverse impacts to any existing water right, and that if public exposure to cooling tower mist is possible, appropriate mitigation or control is provided.

Any delay in the construction of the recycled water supply facilities or lack of full use of recycled water produced by MHCSD could result in an insufficient water supply to serve EAEC before 2010, or impact BBID’s other water customers. Based on conservative estimates of recycled water production from MHCSD, staff believes this significant adverse impact can be mitigated by EAEC using the maximum amount of recycled water produced by MHCSD for its non-potable requirements. Maximum utilization by EAEC of MHCSD’s recycled water would reduce the potential duration of significant adverse impact to BBID’s water supplies to a period between 2010 – 2020, considering both average and peak water demands by EAEC. On the basis of EAEC’s average annual water demands, BBID might only experience demands in excess of raw water supplies on the order of about 800 afy or 1.5% in excess of its maximum annual supply of 50,000 afy. This incremental reduction in raw water use would result in impacts on raw water supplies and other users of those supplies, but staff believes BBID can address these reduced impacts through conservation improvements and the development of other recycled water resources in the area. Considering the lack of assurances by the Applicant to ultimately implement recycled water supply to EAEC, staff recommends the adoption of **Conditions of Certification SOILS & WATER 5 – 9**, providing assurance that recycled water supply will indeed be implemented. The basis for including requirements for assuring implementation of maximum recycled water supply to EAEC is as follows:

1. Any delay in the construction of the recycled water supply facilities and or lack of full use of recycled water produced by MHCSD (to the extent of EAEC’s water supply

demands) could result in insufficient water supplies needed to serve EAEC before 2010, or otherwise impact BBID's other water customers.

2. MHCSD is a willing supplier of recycled water to BBID, the local water purveyor, and MHCSD has committed to provide all of the recycled water it produces for use by EAEC to the extent EAEC has demands for such use.
3. BBID, as the local water purveyor, is willing to supply EAEC with recycled water. In support of this endeavor, BBID has adopted a Recycled Water Policy, and executed an MOU with the Applicant.

On-Site Water Storage

In its Supplement B to the AFC, the Applicant proposed to reduce the on-site raw water storage capacity (combined for fresh and recycled water) from 10 million gallons to only 5 million gallons. The on-site water storage is intended to supply both plant water makeup needs, and a standby of a minimum of 240,000 gallons for fire suppression based on a flow rate of 2,000 gpm for 2 hours. Considering that at least 5% of the storage (or 250,000 gallons) will be unusable storage in the tank in order to assure that fire water is ultimately available from the bottom of the tank, the remaining usable storage for plant water makeup is about 4.5 million gallons. Based on peak water demands of 6,411 gpm, the 4.5 million gallons of on-site storage only represents about a 12-hour reserve of water supply. In contrast, staff's experience in studying the reliability of recycled water supply for other power plant licensing cases, is that it is common (although infrequent) for wastewater treatment plants like the one constructed to serve MHCSD to experience interruptions in treatment and effluent for up to 24 hours. Furthermore, staff's experience with the reliability of water supply from open canal systems such as will serve EAEC, is that interruptions in supply can occur for more than 24 hours due to maintenance or emergency repairs. Therefore, staff concludes that in order to maintain reliability in water supply, EAEC's on-site storage capacity should be a minimum of 10 million gallons, a volume adequate to supply plant water makeup needs for 24 hours. **Condition of Certification SOILS & WATER 7** includes this requirement for minimum storage. The additional 5 million gallon tank is expected to require a capital investment of about $3 million based on the Applicant's own estimates (EAEC 200t, Data Request #84).

Reclaimed Stormwater

Stormwater is collected and detained prior to discharge. Stormwater must be of high quality in order to be discharged to surface waters. The high quality required for surface discharge is likely higher than any of the candidate water sources. The applicant could capture and recycle stormwater as part of its water supply conservation measures. Average annual precipitation is 12 inches, and would yield an average annual volume of 29 afy assuming a 90% recovery. A pipeline would be needed from the proposed detention basin to the cooling towers. This would require about 300 lineal feet of approximately 12-inch diameter pipe, and a small pump station with an approximate capacity of 600 gpm in order to recover inflow from the 25-year, 24-hour storm event. This is a very low investment (approximately $10,000) that will save about one-half percent of the annual water demand and will significantly reduce stormwater monitoring and permitting costs. This will have a positive effect on the region's water balance and reduce the risk of degrading down-stream water quality and beneficial uses. **Condition**

of Certification SOILS & WATER 7 includes a requirement for recovery of storm water as a water conservation measure.

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 six 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 dry cooling. The City of Tracy stated that they are currently conducting an environmental review of expanding their recycled water production (which is currently discharged to Old River) from 9 mgd to 16 mgd and improving their treatment level from secondary to tertiary. The city requested that the applicant and BBID consider augmenting the cooling water supply with City of Tracy's recycled water until such time as Mountain House could meet the full demand. Staff also notes that City of Tracy's recycled water supply is being considered as an alternative to the fresh water supply proposed for the Tesla Power Plant under a separate Application for Certification proceeding. Discovery Bay had also indicated their interest in making recycled water available to EAEC. Alternative supplies from both City of Tracy and Discovery Bay were analyzed in staff's analysis. The comparison of alternatives is complex, as each alternative provides a range of benefits and impacts. 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 non-potable 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."

California Constitution, Article X, Section 2 states that "the water resources of the State be put to beneficial use to the fullest extent of which they are capable, and that the waste or unreasonable use or unreasonable method of use of water be prevented, and that the conservation of such waters is to be exercised with a view to the reasonable and beneficial use thereof in the interest of the people and for the public welfare. The right to water or to the use or flow of water in or from any natural stream or water course in this State is and shall be limited to such water as shall be reasonably required for the beneficial use to be served, and such right does not and shall not extend to the waste or unreasonable use or unreasonable method of use or unreasonable method of diversion."

Using the above as guidance, staff has prepared an analysis comparing fresh versus recycled water supplies and dry cooling. The analysis considers six alternatives described as follows:

<u>Alternative 1A (Proposed Project – Fresh & Recycled Water)</u> – Wet Cooling using BBID's fresh water supply augmented by MHCSD's recycled water supply; BBID would initially supply (in 2005) 3,726 acre-feet/year (81%) from fresh water, and MHCSD would supply 890 acre-feet/year (19%) from recycled water. By 2020 or earlier, MHCSD's recycled water supply would provide 4,616 acre-feet/year (100%), assuming full build-out of MHCSD.

<u>Alternative 1B (Proposed Project – Fresh Water Only)</u> – Wet Cooling using BBID's fresh water supply; BBID would supply initially and in all years an average of 4,616 acre-feet/year. This alternative could apply if staff's proposed conditions of certification requiring implementation of recycled water are not adopted, and the Applicant and/or BBID discretionally chooses not to develop the recycled water pipeline from MHCSD for supply to EAEC. Calpine asked staff to evaluate this alternative.

<u>Alternative 2</u> – 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 for the life of the project.

<u>Alternative 3</u> – 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 1,710 acre-feet/year in 2005) during initial years of EAEC operation, and diminishing to zero by about 2010. MHCSD and DBCSD would provide recycled water supply of 890 afy and 2,016 afy respectively during 2005, and all 4,600 acre-feet/year (100%) of project non-potable water needs by about 2010.

<u>Alternative 4</u> – 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 2005.

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. dry cooling for the EAEC is summarized in **Soils and Water Table 14**.

Soils & Water Table 14
Comparison of Cooling Tower Environmental & Performance Characteristics

Environmental Impact	Wet Cooling	Dry Cooling
Water Requirement	High fresh water supply and treatment requirements (4,600 afy)	None for Cooling (83 afy, primarily for steam production)
Water Discharge	High discharge and treatment requirements	None
Plant Efficiency/Fuel Supply	Baseline	Lower plant efficiency or higher fuel demand (Up to a 4% reduction in capacity, or 46 MW)
Plant Emissions	Baseline	Highest for same output
Auxiliary Power Requirements	Some from fans and pumping	Greatest compared to wet and wet/dry
Secondary Emissions – cooling tower drift	Some 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 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 and wet/dry (661' long, 207' wide, 120' high)
Visual Impact -Plume	Visible plume, function of ambient temperatures	No plume
Noise	Least of cooling tower alternatives	Can be higher than wet and wet/dry (65 – 70 dBA @ 400')

The application of a dry air-cooled condenser system is technically feasible and can significantly reduce (99% reduction) the use of water for the EAEC compared to 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 1A, 1B and 2 through 5 are summarized in **Soils and Water Table 15**.

Soils & Water Table 15
Water Supply/Cooling Alternatives - Comparison of Capital & Operating Costs

Cost Component	Alt. 1A	Alt. 1B	Alt. 2	Alt. 3	Alt. 4	Alt. 5
	MHCSD & BBID	BBID	DBCSD & BBID	MHCSD & DBCSD	City of Tracy	Dry Cooling, BBID
	Fresh & Recycled	Fresh Only	Fresh & Recycled	Fresh & Recycled	Recycled	Fresh Only
Tertiary Treatment of Source Water	$0	$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		$2,000,000
	(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	$0	$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	$1,500,000
EAEC Water Treatment Additions or Savings	$0	$0	$1,308,000	$1,308,000	$1,308,000	
Annual EAEC Water Treatment Operations	$1,109,000	$1,109,000	$1,580,000	$1,580,000	$1,580,000	
Pres. Value of Annual Water Treatment Op's	$14,724,941	$14,724,941	$20,978,725	$20,978,725	$20,978,725	$0
	(600 AF x $100/AF)	(4600 AF x $100/AF)	(2248 x $100/AF)	(100 x $100/AF)		(83 AF x $60/AF)
Annual Water Purchase Cost - Fresh	$60,000	$460,000	$224,800	$10,000	$0	$5,000
Pres. Value of Annual Water Purch's	$796,660	$6,107,730	$2,984,821	$132,777	$0	$66,388
	(4000 AF x $48/AF)		(2352 x $48/AF)	(4500 AF x $48/AF)	(4600 AF x $0/AF)	
Annual Water Purchase Cost - Recycled	$192,000		$113,000	$113,000		$0
Pres. Value of Annual Water Purch's	$2,549,313	$0	$1,500,377	$1,500,377	$0	$0
Wet Cooling Tower (excl Pipeline & Wtr Trtmt)	$32,337,000	$32,337,000	$32,337,000	$32,337,000	$32,337,000	$0
Annual Wet Cooling Operating Costs	$720,000	$720,000	$720,000	$720,000	$720,000	$0
Present Value of Wet Cooling Op's	$9,559,925	$9,559,925	$9,559,925	$9,559,925	$9,559,925	$0
Dry Cooling Tower (excl Pipeline & Wtr Trtmt)	$0	$0	$0	$0	$0	$79,700,000
Annual Dry Cooling Operating Costs	$0	$0	$0	$0	$0	$246,000
Present Value of Dry Cooling Op's	$0	$0	$0	$0	$0	$3,266,308
Subtotal - All Capital Costs	**$56,200,000**	**$48,200,000**	**$66,508,000**	**$74,508,000**	**$62,108,000**	**$83,200,000**
PV of All Costs (2001 $, 7%, 30 Years)	**$83,830,840**	**$78,592,596**	**$101,531,849**	**$106,679,804**	**$92,646,650**	**$86,532,696**
Avg. Annual Rate of Total Costs	**$6,313,669**	**$5,919,154**	**$7,646,810**	**$8,034,525**	**$6,977,626**	**$6,517,158**
Incremental Power Prod. Cost ($/KWH)	**$0.00097**	**$0.00091**	**$0.00117**	**$0.00123**	**$0.00107**	**$0.00100**

1) Avg. Annual Generation is estimated at 6,530,580 MWH/yr assuming a Capacity Factor of 70% x 1,065 MW x 8,760 Hours/yr;

2) 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
3) Costs used in this analysis are primarily the cost data supplied by the Applicant (EAEC 2001t, Response to Data Request #84) and revised according to the Applicant's PSA Comments, Set 1.

4) For Alternative 1A, although fresh water would be phased out to the greatest extent by 2020, a weighted average use of 600 afy over 30 years was used for economic consideration.

5) A rate of $48/AF for recycled water was used assuming BBID's purchase from MHCSD based on the Applicant's estimate as as provided in Data Response #86 (EAEC 2001p, page 30).

6) A rate of $100/AF for fresh water purchased from BBID was used based on BBID's indication to staff as documented in (CEC 2002aa)

In comparing Alternatives 1A and 1B, the proposed project using combined recycled water for non-potable requirements augmented by fresh water (Alt. 1A) results in an investment of approximately $5 million more ($84 million vs. $79 million) over the 30-year life of the project. Converting these costs to annual expenses results in a difference of about $400,000/year. Considering the incremental effect of water supply and treatment on power production costs, Alternative 1A results in a minimally detectable difference of $0.00006/KWH.

Results of the overall analysis comparing various water supply and cooling alternatives in terms of environmental and cost considerations, are summarized as follows:

Soils & Water Table 16
Summary of the Water Supply and Cooling Alternatives

Issue or Measure	Alt. 1A	Alt. 1B	Alt. 2	Alt. 3	Alt. 4	Alt. 5
	Wet Cooling MHCSD Recycled & BBID Fresh Water Supplies	**Wet Cooling BBID Fresh Water Supplies**	**Wet Cooling DBCSD Recycled & BBID Fresh Water Supplies**	**Wet Cooling MHCSD, DBCSD Recycled & BBID Fresh Water Supplies**	**Wet Cooling City of Tracy Recycled Water Supply**	**Dry Cooling BBID Fresh Water Supply**
Ultimate Dependency On Fresh Water (afy)	3,726 – 0 by 2020	4,616	2,248	1,710 – 0 by 2010	0	83
Water Quality before Treatment (TDS in mg/l)	174 - 573	174	748	1,000	1,020	174
Effect of Recycled Water Use to Public Health	None (Will be Tertiary Treated per Title 22)	Not Applicable	Need Tertiary Treatment of DBSCD's Wastewater	Need Tertiary Treatment of DBSCD's Wastewater	Planning Tertiary Treatment	Not Applicable
Adverse Effects to Downstream Water Rights	None	None	None	None	None	None
Degradation to Water Quality	No Significant Impact; No change compared to existing conditions	Slight Degradation No Significant Impact	Improved by avoiding DBCSD existing discharge	Improved by avoiding DBCSD existing discharge	Improved by avoiding existing Tracy discharge	No Significant Impact
Injury to Plantlife, Fish & Wildlife	No Significant Impact	No Significant Impact	No Significant Impact	No Significant Impact	No Significant Impact	No Significant Impact
Present Value of Capital and Operating Costs	$84 MM	$79 MM	$102 MM	$107 MM	$93 MM	$87 MM
Incremental Power Prod. Cost ($/KWH)	**$0.00097**	**$0.00091**	**$0.00117**	**$0.00123**	**$0.00107**	**$0.00100**

As a result of this analysis of alternatives, staff found that Alternative 5 – Dry Cooling would result in the most favorable conservation of water resources and is about equivalent to the next most favorable alternative in terms of other environmental impacts when compared to the Applicant's current proposal. However, 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. Considering the loss of generation capacity/energy and the availability of recycled water, Dry Cooling does not appear to be a necessary alternative if the EAEC where to implement Alternative 1A which would result in only temporary impacts to raw water supplies. This alternative differs from the Applicant's current proposal that is a qualified commitment to use at most 60 percent recycled water from MHCSD under terms acceptable to EAEC.

Of the alternatives considering Wet Cooling, Alternative 1A – Recycled Water from MHCSD augmented by Fresh Water from BBID is an acceptable alternative subject to adopting the Conditions of Certification to assure implementation of 100 percent recycled water use for non-potable project demand. Alternative 1B on the other hand, staff believes would be a waste or unreasonable use of high quality water under the California Constitution Article X, Section 2, and related statutes and policies.

Under Alternative 1A, staff believes that EAEC use recycled water only for cooling and other non-potable requirements no later than 2018, and will no longer rely on fresh water for non-potable requirements. The quality of recycled water originating from MHCSD is adequate to meet EAEC's needs, and the power plant will be designed and constructed to accommodate use of the recycled supply. The recycled water will be treated to tertiary standards in accordance with Title 22 and will have no effects on public health. At this time, no party has claimed potential injury to downstream water rights as a result of the project. DWR had previously indicated its concerns for potential injury to SWP contractors and/or the Delta environment, but has since developed an agreement with BBID to resolve its concerns for potential injury. No significant change to Delta water quality should occur as a result of serving fresh water to EAEC in the interim until recycled supply is adequate, as the SWP will acknowledge BBID's senior water rights and maintain environmental quality controls as prescribed under CalFed. And finally, the cost of supplying recycled water is comparable to, and only slightly more than the cost of supplying solely fresh water (Alternative 1B) over the life of the project. The cost difference between Alternatives 1A and 1B amount to about $5 million as a present value over the life of the project (compared to an initial plant investment on the order of $500 million), or $400,000/year when put in terms of an annual average cost over the 30-year life of the project, or $0.00006/KWH as an incremental cost of power production. Therefore, staff is recommending Alternative 1A - Recycled Water from MHCSD for all non-potable requirements augmented by Fresh Water from BBID as the most favorable alternative. And finally, the cost of supplying recycled water is within the range of alternatives considered and proposed by the Applicant. It should be noted that staff's recommendation should in no way be interpreted to discourage the development of other sources of recycled water to serve EAEC in addition to MHCSD to reduce raw water use earlier or expand reliability.

STATE STATUTORY AND POLICY GUIDANCE

Staff, in making its recommendations, also relies on statutory findings and policies that show the State's position regarding the protection of water quality, conservation of fresh inland water for certain uses and the pursuit of alternative water resources for non-potable applications. In fact, Section 13146 of the Water Code specifies that State offices, departments and boards in carrying out activities which affect water quality, shall comply with state policy for water quality control unless otherwise directed or authorized by statute, in which case they shall indicate to the state board in writing their authority for not complying with such policy. These policies include both State statutes and adopted policies.

> Water Code Section 1254 states "(i)n acting upon applications to appropriate water the board (SWRCB) shall be guided by the policy that domestic use is the highest use and irrigation is the next highest use of water." Staff believes that this guiding

policy codifies a fundamental determination by the state for reserving the highest quality water for the highest uses (domestic and irrigation), particularly in reserving water suitable for potable use for domestic purposes.

Water Quality Control Policy on the Use and Disposal of Inland Waters Used for Powerplant Cooling (adopted by the Board on June 19, 1975 as Resolution 75-58) is the principle policy of the SWRCB that specifically addresses the siting of energy facilities. This policy states that fresh inland waters should only be used for power plant cooling if other sources or other methods of cooling would be environmentally undesirable or economically unsound. 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 includes cooling water discharge prohibitions such as land application.

The SWRCB has adopted a policy for maintaining existing high quality waters to the maximum extent possible contained in SWRCB Resolution 68-16. Essentially it states that the existing high water quality must be maintained until demonstrated to the State that any proposed change will be consistent with the maximum benefit to the people of the state and will not unreasonably affect present or future beneficial uses. Any activity which discharges a waste to existing high quality waters will be required to provide the best practicable treatment necessary to assure that pollution or nuisance will not occur and that the highest water quality, consistent with maximum benefit to the people of the State, will be maintained.

State Water Resources Control Board Resolution 77-1 encourages and promotes reclaimed water use for non-potable purposes.

The California legislature's Water Recycling Act of 1991 (Water Code § 13575 et seq.) makes several findings and declarations, including:

The environmental benefits of reclaimed water include a reduced demand for water in the Sacramento-San Joaquin Delta, reduced discharge of waste into the ocean, and the enhancement of groundwater basins, recreation, fisheries, and wetlands;

The use of reclaimed water has proven to be safe, and the State DHS is updating regulations for its use;

The use of reclaimed water is a cost-effective, reliable method of helping to meet California's water supply needs; and

Retail water suppliers and reclaimed water producers and wholesalers should promote the substitution of reclaimed water for potable and imported water in order to maximize the appropriate cost-effective use of reclaimed water in California.

Staff's recommendation that EAEC be required to use 100 percent recycled water for its non-potable requirements at the earliest possible date, but no later than 2020, is consistent with the State's statutory findings and policies for the protection of water quality, conservation of fresh inland water and the use of recycled water.

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 a landfill. The Applicant has estimated that generation of salt cake 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. Staff estimates that 100 percent recycled water use would result in less than 20 tons/day.

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). Staff is recommending **Condition of Certification SOILS & WATER 13** to address this uncertainty and insure no adverse impacts occur during the construction or operation of this facility to soil and water resources.

CUMULATIVE IMPACTS

In addition to EAEC's proposed use of fresh water originating from the Delta, two other AFC proceedings are in progress, which are proposing to use fresh water supply from the Delta. Several residential developments are also proposed or under construction in the area. These are summarized as follows:

Soils & Water Table 17
Cumulative Diversions of Delta Water Resources

Project Name	AFC Proceeding #	Annual Average Quantity of Water (Acre-Feet/Year)
Mountain House Dev't	N/A	9,415
East Altamont Energy Center	01-AFC-04	4,616
Tesla Power Plant	01-AFC-20	5,100
Tracy Hills	N/A	6,000
Tracy Peaker Project	01-AFC-16	30
Total		**25,161**

According to information currently available regarding the Tesla Power Plant, it appears that water diverted to Tesla from the California Aqueduct will be in exchange for groundwater that has been banked by a local water supplier in Kern County. Therefore, there would be no additional diversions of Delta water resources for supply to Tesla Power Plant, but instead there would be increases in banked groundwater withdrawal in Kern County. Another possible supply under consideration for the Tesla project is recycled water from the Tracy wastewater treatment facility. The impacts of additional groundwater withdrawal or other potential impacts to water resources are subject to assessment under the Tesla AFC proceeding.

Power plants are not the only development expected in the area that has the potential to affect water resources. Over the next several years, projected water demand in BBID's service area and areas nearby is expected to increase, primarily to serve the needs of new residential and commercial customers. As stated earlier, BBID projects that this demand will reach 50,615 afy by 2020, without consideration of EAEC's requirements. As agreed between DWR and BBID, the diversions from the Clifton Court Forebay will be limited to 50,000 afy. Calpine proposes primarily to use fresh inland (raw) water that ultimately comes from the Delta until such time as recycled water is available from BBID at which time they anticipate it will meet 50 percent of their demands (assuming recycled water is offered under terms and conditions acceptable to EAEC). Otherwise, Calpine proposes to use 100% fresh water. This proposed use could affect BBID's current customers and any potential future customers of local fresh water in the area served by BBID, such as farmers and or residential customers who must compete for limited high quality supplies and have few if any alternatives to meet their needs. The project will operate for 30-50 years, and this use by EAEC of fresh inland (raw) water could potentially have increasing adverse local and regional effects over time.

Considering the increasing pressures and diminishing supplies of fresh inland water resources in BBID's service area and the local region, staff finds that the use of fresh inland water, when recycled or degraded water resources are available for non-potable needs, represents a potential significant adverse cumulative impact. This impact results in the reduction of fresh water supply available for other uses in the area that lack alternatives to meet their needs. Staff's finding is based on the conclusion that recycled water is clearly available for supply to EAEC, and EAEC's use of raw fresh water is shown to exceed local supplies over time and therefore would result in a significant adverse cumulative impact. The SWRCB has also determined that local surface water supplies in the Sacramento-San Joaquin Delta are already fully appropriated from June 15 – August 31 each year, and not available for new appropriations considered junior in right to those already established (SWRCB, 1998).

As a perspective of existing and projected statewide shortages of fresh water supplies, a number of reports and publications help illustrate the challenges facing California now and in the future to maintain adequate water supplies:

1. <u>DWR's California Water Plan Update 1998</u> – Every five years, DWR is required to prepare a statewide Water Plan addressing projected demands and supplies, and strategies to meet the state's future water needs. In the last completed Water Plan Update -1998, DWR determined that as of 1995, a 1.6 million afy shortage of water supply existed in California. In 2020, the shortage is projected to be 2.4 million afy (DWR, Bulletin 160-98) (DWR, 2002c).

2. <u>DWR's California Water Plan Update 2003</u> – DWR has begun to update its assessment of the state's water supplies and demands with its California Water Plan Update 2003. This new plan will look more broadly than before at programs and conditions affecting the state's water resources. These programs will include evaluating the status and interaction of CALFED, the Colorado River Water Use Plan, the Central Valley Project Improvement Act (CVPIA), the State Water Resources Control Board Bay-Delta water rights hearings, hydroelectric project relicensings and global warming, among other programs and conditions (DWR, 2002d).

3. DWR's SWP Delivery Reliability Report – On August 20, 2002, DWR released its Draft SWP Delivery Reliability Report. The analyses contained in the report conclude that the SWP, using existing facilities and operated under current regulations, can deliver an average between 70 and 75 % of the primary contractual supply (defined as the Table A amount) now and in the future. During dry periods, deliveries are projected to be significantly lower. For example, if conditions similar to 1977 were to repeat, SWP deliveries are projected to be about 20% of the primary contractual supply (DWR, 2002e).

4. California Colorado River Water Use Plan – California is charged with bringing its use of Colorado River Water in line with its allocation. California's normal apportionment is 4.4 million acre-feet/year, and at times has used up to 5.4 million acre-feet/year. A plan for implementing water conservation measures and groundwater storage is being implemented over a 15-year period from 2001 – 2016, in order to accomplish a progressive reduction in California's reliance on Colorado River water to within its normal apportionment (Colorado River Board, 2002a).

5. Global Warming – Scientists are recognizing changing trends in our atmospheric conditions that are already showing effects on our water supplies in California. Over the past century, land and sea temperatures have risen by about 1°F. Since 1958, carbon dioxide levels have increased from about 315 parts per million (ppm) to about 370 ppm, from which there appears a correlation that as carbon dioxide increases, land and sea temperatures increases. The effects are already being realized in our state's water supplies as measurements in the Sacramento River system show that water originating from mountain snowmelt has diminished by about 12% over the last century. A compounding effect is that more intense and earlier snowmelt is being realized, making natural flows in river systems less sustainable over the normal April – July period, and less available to divert to beneficial use and storage for later use in the year (Sacramento Bee, 2002a).

Cumulatively in California, fresh water supplies for consumptive uses are diminishing while the demand for high quality fresh water is increasing. CALFED and the CVPIA Programs have provided significant improvements in environmental protection of sensitive or endangered species and improvements in restoring aquatic habitat conditions in some reaches of streams and the Delta. However, a result of this accomplishment is more water appropriated for environmental needs and less water available for consumptive needs. Between 2001 – 2016, water received by California from the Colorado River will be reduced by 1 million afy. The outlook for the SWP is also limited. Assuming no changes in the rules by which the SWP's operations are governed, DWR estimates that during normal hydrologic conditions, its supply to contractors will average 70 – 75% of primary contractual allocations that cumulatively total about 4.3 million afy at 100%, and during a critically dry year like 1977, that supply will be severely limited to a mere 20%. Combined hydropower and water supply projects are realizing similar reallocations of resources during license renewals under FERC's authority, accomplishing significant improvements for restoration of aquatic habitat, and modifying project operations to better mimic natural stream flows for habitat restoration and recreation purposes, while resulting in less water in storage reserves for meeting future consumptive needs.

Staff recommends that the project be required to use all recycled water produced by MHCSD in order to make available as much fresh surface water for higher priority uses such as agriculture and residential uses and avoid or minimize the potential for significant cumulative impacts. In addition, if other sources of recycled water can be developed earlier, staff encourages the Applicant to assist in doing so in order to avoid a potential shortfall in supplies that would necessitate increases in fresh water diversion or depriving residential and agricultural users of fresh water supplies. Adoption of Staff's proposed Conditions of Certification will result in the proposed EAEC being consistent with State policies and conserve limited fresh inland water.

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 has identified a potentially significant adverse cumulative effect to local water supplies resulting from the use of high quality fresh inland water, but with 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 Soils and Water environmental justice issues related to this project.

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 recommendations to be included in the conditions of certification. Staff reviewed these comments and recommendations. Our responses are summarized as follows:

1. *Alameda County provided a number of comments to consider in the preparation of the Drainage, Erosion and Sedimentation Control Plan.*

   Response: Staff has ensured that Alameda County will have the opportunity to review and comment on the Drainage, Erosion and Sedimentation Control Plan as specified in Condition of Certification Soil & Water 2.

2. *Alameda County provided a number of comments to consider in the preparation of the design of storm water facilities.*

   Response: Staff has ensured that Alameda County will have the opportunity to review and comment on the Storm Water Pollution Prevention Plans for both construction and industrial activities as specified in Conditions of Certification Soil & Water 1 and 3.

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 concerns 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: Alternative 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 percent 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 percent certain, it appears to be a viable alternative to consider for recycled water supply to EAEC.

8. *In its October 30, 2001 letter to Ms. Cheri Davis, the Byron Bethany Irrigation District clarified its water rights with respect to supply of fresh water to EAEC.*

   Response: Staff believes it has represented BBID's water rights to fresh water diversions with respect to quantities and seasons of use as discussed in EAEC

Water Supply – BBID on pages 5.8 -10 through 5.8-12, and Changes in BBID's Historic Use on pages 5.8-17 through 5.8-18.

Discovery Bay Community Services District

Discovery Bay Community District has indicated its interest in supplying recycled water to EAEC.

Response: Staff has included the opportunity for recycled water supply from Discovery Bay Community Services District as Alternatives 2 and 3 in its Possible Alternatives to the Proposed Water Supply as discussed on pages 5.8-27 through 5.8-24.

City of Tracy

In its December 20, 2001 letter to Ms. Cheri Davis, the City of Tracy provided the following comments on the PSA which are summarized as follows:

1. *City of Tracy indicated that they will have adequate capacity of recycled water to serve EAEC, and that the Public Works staff is willing to recommend to the City Council to allow EAEC to purchase recycled water at no cost in consideration of the Applicant contributing for its proportionate share of related capital costs.*

   Response: Staff has included in its economic analysis of water supply alternatives the option to use City of Tracy's recycled water for supply to EAEC.
2. *City of Tracy indicated that in staff's economic analysis of water supply alternatives, that it was unnecessary to include a backup fresh water supply.*

   Response: Staff agrees with City of Tracy, and has revised its economic analysis assumptions for Alternative 4 - City of Tracy Recycled Water Supply to reflect the City's comment.

Contra Costa Water District

In its January 18, 2002 letter to Ms. Cheri Davis, the Contra Costa Water District (CCWD) provided the following comments on the PSA which are summarized as follows:

1. *CCWD's overall interest is in protection of water quality in the Delta, the sole source of CCWD's water supply for 430,000 people. As such, CCWD has a need for full and accurate disclosure of impacts on water quality.*

   Response: Staff recognizes the importance of maintaining Delta water quality, and the direct adverse effect that Delta water quality degradation can have on CCWD's water supply.

2. *CCWD requests that the cumulative impact analysis include consideration of other water projects such as construction of flow and fish barriers in the south Delta and the increase in pumping at the CVP and SWP facilities.*

   Response: Staff believes it has adequately analyzed pertinent issues to the licensing of EAEC in its cumulative impact analysis, as well as including staff-proposed mitigation and conditions of certification that maximize use of recycled water in the interest of maintaining Delta water quality.

3. *CCWD requests that staff incorporate results of water supply and water quality modeling of the Delta into its analysis of EAEC.*

   Response: Staff believes it has established a basis to protect Delta water quality without demonstration through numerical modeling by requiring EAEC to maximize use of recycled water as specified in Conditions of Certification Soil & Water #'s 5 – 9.

4. *CCWD does not agree that using recycled water and reducing wastewater return flows into the Delta is similar to increasing fresh water consumption from the Delta.*

   Response: Staff has deleted this statement consistent with CCWD's request.

5. *CCWD is actively encouraging the RWQCB to require that all new wastewater facilities in the Delta region include tertiary treatment and minimize disposal to waterways, in consideration of stricter regulations on drinking water and the CALFED goal of improved water quality. CCWD strongly opposes the discharge of contaminated wastewater from Mountain House into the drinking water supply for 20 million Californians.*

   Response: Staff has required EAEC to use the maximum amount of tertiary-treated recycled water from Mountain House as specified in Conditions of Certification Soil & Water #'s 5 – 9.

San Joaquin County Board of Supervisors Resolution 406

This resolution states the County's opposition to several proposed consequences of the EAEC including the loss of water to farming and other users as a result of the project's proposed demand.

Response: Staff has determined that Calpine's proposed water supply to EAEC would result in significant adverse impacts to local water supplies and adversely impact other users. As a result, staff is recommending Conditions of Certification that would mitigate these impacts.

PUBLIC COMMENTS

G&DK-4 - *Mr. and Mrs. Kuhn expressed concern regarding the two evaporation ponds as initially proposed for the EAEC.*

Response: 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.

MS-3 - *This plant will use 4,600 acre-feet of water per year. In a state like California, this is an unconscionable use of water when viable alternatives exist.*

Response: Please refer to staff's discussion of potential impacts caused by water use above. Staff has determined that the use of fresh inland water by EAEC could have a potentially significant adverse impact. Staff is recommending several Conditions of Certification to address these impacts.

MS-4 - *How will the crystallized brine from the water treatment plant be disposed of? How will cooling tower blowdown and other wastewater streams be dealt with?*

Response: Please refer to staff's discussion of the proposed wastewater treatment process and possible impacts above. Most wastewater streams will be recycled *and* the crystallized brine will be directed to either drum dryers or a concentrator resulting in a solid salt cake.

MITIGATION

APPLICANT PROPOSED MITIGATION

Soils

The applicant proposes to incorporate standard BMPs into the project design for construction and operation to mitigate erosion and sedimentation impacts.

Ground water

The applicant has generally described the proposed BMPs for spill prevention and control within the Storm Water Pollution Prevention Plan (SWPPP) to minimize the potential for ground water contamination. No groundwater is to be used by the project.

Surface Hydrology

As proposed, all storm water not routed to the ZLD system is to be directed to the detention pond.

Storm Water

The applicant has submitted a draft SWPPP that generally addresses BMPs. More site specific BMPs will be required in the project design for construction and operation to reduce erosion and sedimentation impacts and their possible impacts to surface water quality. Measures established within the SWPPP regarding spill control would also protect surface water resources. Areas will be curbed or bermed where there is a possibility for runoff to encounter contaminants. The runoff from these portions of the site will be routed through an oil/water separator and then to the ZLD system, eliminating this potential source of polluted runoff. The applicant will be required to meet general storm water requirements of the NPDES permit.

Wastewater Disposal

To reduce water requirements and eliminate wastewater discharges for the project, the applicant has proposed a ZLD system. Sanitary wastewater is to be directed to a mounded septic system and drain field.

STAFF PROPOSED MITIGATION

Soils

Staff recommends that the applicant be required to meet storm water requirements of the general NPDES permit. As required by Central Valley RWQCB Order 99-08-DWQ (Storm water during construction) and Order 5-00-175 (discharge of short duration or low threat), a SWPPP would be implemented to minimize pollutants in stormwater. In addition, the Applicant will be required to develop and implement site specific Drainage, Erosion and Sedimentation Control Plan for the entire project (including ancillary facilities) that address standard erosion runoff and sedimentation impacts for construction, post-construction, and operational phases. This plan will comply with all applicable local requirements. These requirements are addressed in **Conditions of Certification SOILS & WATER-1** and **SOILS & WATER-2.** The applicant must revise the draft plans to provide the following amendments and additions within the final plans for the entire proposed EAEC project:

The topographic features of the proposed project including areas involving all proposed pipeline construction, laydown (staging) area, transmission upgrades, and stockpile location(s). The mapping scale should be at least 1"= 100' (1"=50' recommended). Sufficient surrounding area including the topography and existing features should also be provided on the drawings.

A construction schedule that addresses all BMP installation, maintenance and removal sequences of events from initial site mobilization to final stabilization (i.e. vegetation/asphalt) and plant operation.

Proposed contours should be shown tying in with existing ones. All proposed utilities including storm water facilities should be shown on the plan drawings. All erosion and sedimentation control facilities should be shown on the drawings. The drawings should contain a complete mapping symbols legend that identifies all existing and proposed features including the soil boundary and a limit of construction. The limit of construction boundary should include the project facility, pipeline areas, stockpile areas, laydown areas, and any off-site staging areas. The limit of construction ensures all work is confined to the proposed EAEC project in order to protect all surrounding areas not involved in construction or operation of the proposed project.

Silt fencing and sandbags should be used to trap sediment, and not as runoff conveyance facilities. Earthen berms or channels can be substituted to intercept sediment-laden runoff and direct it into the sediment retention basin/trap. A sediment trap should be used for drainage areas less than five acres and a sediment basin should be used for drainage areas greater than five acres.

All excavated material should be kept away from active flows. Site specific BMPs shall be included in narrative and drawing portions of the erosion and sediment control plan. The soil should be covered via a liner or anchored mulch. Areas disturbed during construction should be stabilized via permanent vegetation upon completion of the process.

Specific BMPs to be employed for all project-related construction including, but not limited, to access roads, directional drilling / tunneling, linear facilities, and any off-site staging areas are to be shown on legible drawings of appropriate scale.

Proposed vegetative areas and a description of revegetation procedures are to appear on the drawings.

Soil stockpile management BMPs for water and wind erosion.

Maintenance and monitoring protocol for erosion/storm water control.

Ground Water

No ground water is to be used by the project and staff is requiring proper review and approval of the proposed septic system for groundwater protection (see **Condition of Certification SOILS & WATER-4**).

Surface Hydrology

As proposed, the EAEC is to be operated as a 'zero-liquid discharge' facility thereby eliminating the need to obtain a NPDES permit other than for storm water discharges. EAEC will be required to comply with the general NPDES requirements that regulate storm water discharges. The EAEC will supply all information required by the RWQCB and Energy Commission staff to determine compliance with the NPDES requirements for storm water discharge. This includes the required SWPPPs. The applicant will be responsible for all monitoring and reporting guidelines and other provisions included in the general storm water permits. This requirement is contained in **Conditions of Certification SOILS & WATER-1 and SOILS & WATER-3**.

Water Supply

Considering the potentially significant adverse cumulative effects to local water supply and the lack of assurances by the Applicant to ultimately use a recycled water supply for EAEC, staff has included **Conditions of Certification SOILS & WATER 5 – 9**, providing assurance that recycled water supply will indeed be fully implemented. The basis for including requirements for assuring implementation of recycled water supply to EAEC is as follows:

1. MHCSD is a willing supplier of recycled water to BBID who is the local water purveyor, and MHCSD has committed to provide all of the recycled water it produces for use by EAEC to the extent EAEC has demands for such use.

2. BBID, as the local water purveyor, is willing to supply EAEC with recycled water, and in support of this endeavor, has adopted a Recycled Water Policy, and executed an MOU with the Applicant.

3. Any delay in the construction of the recycled water supply facilities and or lack of full use of recycled water produced by MHCSD (to the extent of EAEC's water supply demands) could result in insufficient water supplies needed to serve EAEC before 2010, or otherwise impact BBID's other water customers.

To mitigate any potential adverse impacts to local fresh water supplies or other users of fresh water and address inadequacies of fresh water supplies, staff also is recommending that EAEC be required to use recycled water for 100 percent of all non-potable requirements no later than January 1, 2020 (**Condition of Certification SOILS & WATER 5**).

Process and Sanitary Wastewater

The project will operate with a zero-liquid-discharge system that will eliminate all process wastewater discharge. Since the applicant has proposed no back-up for the ZLD system, staff recommends monitoring of the ZLD system and on-site storage facilities (**Condition of Certification SOILS & WATER 11 & SOILS & WATER 12**) as well as facility shut-down in the event of a disruption to the operation of the ZLD system. Compliance with this condition should ensure proper handling, storage and disposal of wastewater generated at the EAEC.

The on-site septic system and drainfield must be designed according to applicable county laws in order to prevent any significant impacts to water quality. **Condition of Certification SOILS & WATER-13** requires review of the final design plans by the CPM and Alameda County for the protection of water quality. The plans must be approved by the Energy Commission before the start of septic system construction activities.

Storm Water

As stated in the **Surface Hydrology** mitigation discussion above, EAEC will be required to comply with the NPDES requirements that regulate storm water by establishing effluent limitations and monitoring and reporting requirements for construction activities storm water, low-threat or short duration discharge, and the industrial activities (operational) dictated by the storm water general permit. The draft SWPPP will need to be revised to be site specific and comply with the guidelines provided in Water Quality Order 99-08-DWQ and 97-03-DWQ. In addition, staff is recommending that stormwater flows be directed to the cooling process to conserve fresh water resources.

COMPLIANCE WITH LORS

Calpine's proposed EAEC has been considered with regard to applicable laws, ordinances, regulations and standards (LORS). Staff believes that if the proposed Conditions of Certification are required, the project will comply with LORS. For this reason, staff recommends that the project not be licensed without the proposed Conditions of Certification.

CONCLUSIONS

Staff concludes use of only fresh water by the project for non-potable needs would result in a significant adverse impact by diminishing local water supply, potentially depriving BBID's other customers of fresh water or resulting in inadequate supplies to the EAEC project itself. Staff also believes that potentially significant adverse cumulative impacts to other fresh water users (i.e., residential and agriculture) could result if EAEC does not maximize its use of recycled water for cooling and non-potable requirements. The use of reclaimed water for cooling is well proven and could ordinarily serve 100 percent of the project's non-potable water demands prior to 2020. Several sources of recycled water suitable for meeting EAEC's non-potable requirements are being developed in the area and will be available by as early as 2003. MHCSD has committed to supply all of its recycled water for use by EAEC. Staff also concludes that recycling of the storm water to the cooling tower basin is a reasonable and economic means to conserve water, and will avoid discharge of storm water offsite.

Based on the facts of this case, staff has determined that EAEC's use of high quality fresh inland water for cooling, process water and other non-potable uses when recycled water is available is wasteful, an unreasonable use or unreasonable method of water use. Staff's determination that recycled water use be maximized by EAEC is supported by statutory and policy guidance. The incremental effect of EAEC using recycled water supply on its power production costs, as shown under Alternative 1A , results in a minimally detectable difference of about $0.00006/KWH over the life of the project compared to using all fresh water (Alternative 1B). The MHCSD recycled water will be treated to tertiary standards in accordance with Title 22, is of a quality sufficient for use by EAEC, and will have no effects on public health. Staff's recommendation that EAEC be required to use 100 percent recycled water for its non-potable requirements at the earliest possible date, but no later than 2020, is consistent with the State's statutory findings and policies for the protection of water quality, conservation of fresh inland water and the use of recycled water.

The proposed EAEC project will comply with applicable LORS, be consistent with established state policy regarding the conservation of fresh water supplies and result in a less than significant impact to other fresh water users if the Conditions of Certification recommended by staff are required. Staff recommends that the project not be licensed without these Conditions of Certification included as part of the license.

PROPOSED CONDITIONS OF CERTIFICATION

The following conditions have been developed for the project:

SOILS&WATER 1: The project owner shall comply with all of the requirements of the General NPDES Permit for Discharges of Storm Water Associated with <u>Construction</u> Activity. The project owner, as required, shall develop and implement a Storm Water Pollution Prevention Plan (SWPPP) for the construction of the entire project. Prior to beginning any site mobilization associated with any project element, the project owner shall submit to the CPM a copy of the Notice of Intent for Construction accepted by the RWQCB and obtain Energy Commission CPM approval of the construction activity SWPPP for EAEC.

<u>Verification</u>: No later than 60 days prior to the start of site mobilization for any project element, the project owner shall submit a copy of the SWPPP required under the General NPDES Permit for Discharges of Storm Water Associated with Construction Activity to Alameda County for review and comment, and to the CPM for review and approval. The SWPPP will include copies of the Notice of Intent for Construction accepted by the RWQCB and any permits for EAEC that specify requirements for the protection of stormwater or water quality. Approval of the SWPPP by the CPM must be received prior to site mobilization for any project element.

SOILS&WATER 2: Prior to beginning any site mobilization activities for any project element, the project owner shall obtain CPM approval for a site-specific Drainage, Erosion and Sedimentation Control Plan that addresses all project elements. The plan shall address revegetation and be consistent with the grading and drainage plan as required by **Condition of Certification CIVIL-1**.

Verification: No later than 60 days prior to the start of any site mobilization for any project element, the project owner shall submit the Drainage, Erosion and Sedimentation Control Plan to the CPM for review and approval. No later than 60 days prior to start of any site mobilization, the project owner shall submit a copy of the plan to Alameda, Contra Costa and San Joaquin Counties for review and requesting any comments be provided to the CPM within 30 days. The plan must be approved by the CPM prior to start of any site mobilization activities.

SOILS&WATER 3: The project owner shall comply with all of the requirements of the General NPDES Permit for Discharges of Storm Water Associated with Industrial Activity. The project owner, as required, shall develop and implement a Storm Water Pollution Prevention Plan (SWPPP) for the operation of EAEC. The project owner shall submit to the CPM a copy of the Notice of Intent for Operation accepted by the RWQCB and obtain approval of the General Industrial Activities SWPPP from the Energy Commission CPM prior to commercial operation of the EAEC.

Verification: No later than 60 days prior to the start of commercial operation, the project owner shall submit to the CPM a copy of the SWPPP required under the General NPDES Permit for Discharges of Storm Water Associated with Industrial Activity to Alameda County for review and comment, and to the CPM for review and approval. The operational SWPPP shall include copies of the Notice of Intent for Operation accepted by the RWQCB and any permits for EAEC that specify requirements for the protection of stormwater or water quality. Approval of the operational SWPPP by the CPM must be received prior to start of commercial operation.

SOILS&WATER 4: The on-site septic system shall be designed and operated to prevent any adverse impacts to water quality. Prior to construction of the on-site sanitary wastewater treatment facility (septic system), the project owner shall obtain CPM approval for this system. Prior to CPM approval, written confirmation shall be submitted by the project owner from the Alameda County that the proposed facility design meets all applicable County requirements.

Verification: No later than 60 days prior to construction of the on-site domestic wastewater treatment facility for EAEC, the project owner shall prepare detailed engineering drawings for this facility and submit these drawings with a detailed description to the CPM and Alameda County for review. The detailed description shall include information on infiltration rates, existing groundwater quality and depth to groundwater. Within 60 days of submitting the detailed engineering drawings, the project owner shall provide written confirmation to the CPM from the Alameda County that the design meets all applicable County requirements.

SOILS&WATER 5: Total water use by the project owner for the operation of EAEC and associated landscape irrigation shall not exceed an annual average of 4,616 acre-feet, a peak annual demand of 7,000 acre-feet and a peak daily flow of 9.1 mgd. Water used by EAEC shall not adversely impact fresh water supplies to municipal or agricultural customers of BBID. EAEC shall use tertiary treated, recycled water for all of its non-potable operational requirements as soon as possible, **but no later than January 1, 2020**. Until 2020, raw water supplied by BBID from Canal 45 may supplement the recycled water supply to the extent needed. Beginning in 2020 and thereafter, in the event of an unavoidable interruption in recycled water supply, or otherwise should fresh water be needed to support peaking demands, up to 10 percent non-recycled water use will be allowed based on the actual annual EAEC water use for the particular year. **If this specified water supply is not available or the specified limits will be exceeded prior to the end of the calendar year, the project owner shall immediately notify the CPM.** The notification must specify the cause and proposed new source of recycled water, modified cooling technology, or other reasonable solution subject to approval by the CPM.

Verification: In the annual compliance report, the project owner shall submit a report to the CPM that documents the previous year's actual fresh and recycled water use on a monthly basis consistent with requirements of **Condition of Certification SOILS&WATER 8**, distinguishing sources of water and their uses. Annual average will be calculated using actual project water use over consecutive five-year increments starting with the first year of operation.

SOILS&WATER 6: The project owner shall submit to BBID a written request, pursuant to Water Code section 13580.7, to enter into an agreement in order to provide recycled water service to EAEC. After submittal of this request, the project owner shall enter into a Water Supply Service Contract with BBID setting forth the rate and conditions for fresh water and recycled water supply. The contract shall specify that EAEC will have first priority for allocation of recycled water necessary to serve EAEC. The contract shall also set forth each party's responsibility for the design, construction, and funding of the recycled water supply pump station and pipeline from MHCSD. The contract shall be executed prior to the construction of any project structures or facilities and a signed copy submitted to the CPM. The pipeline to convey recycled water from MHCSD's treatment facility to EAEC shall be built prior to the start of plant operation.

Verification: No later than 60 days prior to mobilization, the project owner shall submit proof to the CPM that BBID has received the request. No later than 120 days after the request is submitted the project owner shall submit to the CPM an executed Water Supply Service Contract with BBID for fresh and recycled water supply to EAEC. No later than 30 days prior to plant operation, the project owner shall submit evidence to the CPM that the recycled water supply pipeline has been built and is capable of conveying 5.4 mgd to EAEC.

SOILS&WATER 7: The EAEC project shall include the following specific design features to ensure maximum use of recycled water:

a) Plant piping shall be installed to allow recycled water to be used for cooling tower makeup and landscape irrigation. Cross connection protection between raw, recycled, and potable water systems shall be in accordance with Chapter 19, Backflow Prevention and Cross Connection Control, of Title 22, California Code of Regulations as proposed in the March 20, 2002 Draft Cross Connection Control Regulations.

b) Systems shall be included to facilitate the feed of a second oxidizing biocide (in addition to sodium hypochlorite) and also a non-oxidizing biocide.

c) The landscaped irrigation system shall be plumbed to use recycled water.

d) The surface condenser shall be constructed of materials compatible with recycled water.

e) The recycled water pipeline from the Mountain House Community Services District (MHCSD) to EAEC shall be sized to supply peak EAEC demand with 100 percent recycled water from MHCSD.

f) On-site raw water storage shall be a minimum of 10 million gallons.

g) Storm water shall be recycled to the cooling tower basin.

Approval of the final design of the water supply and treatment system by the CPM shall be obtained prior to the start of construction of these systems.

Verification: At least 60 days prior to the start of construction of the water supply system, the project owner shall submit to the CPM its water supply system design demonstrating compliance with this condition. These required features shall be included in the final design drawings submitted to the CBO as required in **Condition of Certification CIVIL-1**. Approval of the final design of the water supply and treatment system by the CPM shall be obtained prior to the start of construction of the systems.

SOILS&WATER 8: Prior to the use of any water by the EAEC, the project owner shall install metering devices as part of the water supply and treatment system to monitor and record in gallons per day, 1) total volumes of each raw and recycled water supplied to EAEC, and 2) volumes used of each source for cooling purposes, potable water treatment system, non-cooling process water supplies, irrigation, wash water, demineralized water and turbine injection. These metering devices shall be operational for the life of the project.

An annual summary of daily water use by EAEC, differentiating between raw, potable and recycled water and the uses of each at EAEC, shall be submitted to the CPM in the annual compliance report.

Verification: No less than 60 days prior to the start of operation of EAEC, the project owner shall submit to the CPM evidence that metering devices have been installed and are operational on the pipelines serving and within the project. These metering devices shall be capable of recording the quantities in gallons of water delivered to EAEC and differentiate between uses of these supplies by EAEC in order to report daily water demand (including irrigation). The project owner shall provide a report on the servicing, testing and calibration of the metering devices and operation in the annual compliance report.

The project owner shall submit a water use summary report to the CPM in the annual compliance report for the life of the project. The annual summary report shall be based on and shall distinguish recorded daily use of raw, potable and recycled water for all project uses, including landscape and agriculture irrigation. Included in the annual summary of water use, the project owner shall submit copies of meter records from MHCSD documenting the quantities of tertiary-treated disinfected wastewater produced (in gpd) by their treatment plants over the previous year. The report shall include calculated monthly range, monthly average, and annual use by the project in both gallons per minute and acre-feet. For subsequent years this information shall also include the yearly range and yearly average water used by the project.

SOILS&WATER 9: Prior to construction of the fresh water pipeline, the project owner shall provide the CPM with a copy of the Encroachment Permit for the installation of the fresh water pipeline under the Delta-Mendota Canal. Approval by the U.S. Bureau of Reclamation and Delta-Mendota Water Authority must be obtained prior to initiating any directional drilling activities.

Verification: At least 30 days prior to construction, the project owner shall submit to the CPM a copy of the Encroachment Permit issued by the U.S. Bureau of Reclamation and Delta-Mendota Water Authority.

SOILS&WATER 10: Prior to construction of the Fresh Water Pump Station located at Canal 45, the project owner shall submit to the CPM a copy of an approved Building Permit from Contra Costa County Public Works Department, and evidence of having complied with all applicable requirements.

Verification: At least 30 days prior to start of EAEC site mobilization, the project owner shall submit to the CPM a copy of the County approved Building Permit issued by Contra Costa County Public Works Department.

SOILS&WATER 11: Wash wastewater resulting from periodic cleaning of the compressors and heat recovery steam generators shall be contained on-site in a sump with the contents of the sump periodically pumped out by a vacuum truck and transported off-site for disposal at an appropriately licensed facility.

Verification: The project owner, in the annual compliance report, shall provide an accounting summary of the quantity and quality of wash and chemical cleaning water contained on-site, including the frequency of pumping, and the volume of water transported off-site for disposal. The accounting shall include documentation of the analytical reports required for disposal, and pre-treatment processing, if required for disposal.

SOILS&WATER 12: Surface or subsurface disposal of process wastewater or contaminated stormwater from EAEC is prohibited. The project owner shall treat all appropriate wastewater streams with a zero liquid discharge (ZLD) system that results in a residual cake solid waste and recycle stormwater flows to the cooling towers.

Verification: Within 60 days following the commencement of project operations, the project owner shall submit to the CPM the final design of the zero liquid discharge system, including schematic, narrative of operation, maintenance schedules, on-site storage facilities, containment measures and influent water quality. This information shall also include the results of the Waste Extraction Test of the residual cake solid waste from the zero liquid discharge system. In the annual compliance report, the project owner will submit a status report on operation of the zero liquid discharge system, including disruptions, maintenance, volumes of interim wastewater streams stored on site, volumes of residual cake solids generated and the landfills used for disposal. In the event of ZLD system shutdown or any maintenance affecting the ability for EAEC to continue treatment at the rate of its production of wastewater, the project owner shall submit to the CPM a description of their temporary alternative disposal method for review and approval. In addition, the project owner shall submit to the CPM copies of the annual monitoring report for storm water as normally submitted to the Central Valley RWQCB under the General NPDES Permit for Discharges of Storm Water Associated with Industrial Activity.

SOIL&WATER 13: Potable water for the EAEC shall be provided by an on-site domestic (potable) water treatment system. Prior to installation of the on-site domestic (potable) water treatment system, the project owner shall submit detailed engineering drawings and a narrative description of this facility and its uses to the California Department of Health Services' (DHS) Drinking Water Program for review and approval. A water supply permit approved by DHS' Drinking Water Program for the on-site domestic water treatment facility shall be obtained by the project owner and a copy submitted to CPM prior to use of the system.

Verification: Prior to the installation of the on-site domestic water treatment system, copy of the approved water supply permit issued by DHS shall be submitted to the CPM.

REFERENCES

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Burns, John M., PE and Micheletti, Wayne C. November 4, 2000. Comparison of Wet and Dry Cooling Systems for Combined Cycle Power Plants.

CEC (California Energy Commission) 2001a. First Set of Data Requests. Dated and docketed May 10, 2001.

CEC (California Energy Commission) / John Kessler 2001b. Report of Conversation with SWRCB. Dated July 10, 2001 and docketed July 12, 2001.

CEC (California Energy Commission) 2001c. Second Set of Data Requests. Dated July 19, 2001 and docketed July 20, 2001.

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CEC (California Energy Commission) / John Kessler 2001f. Report of Conversation with Andrew Sawyer, Assistant Chief Counsel, SWRCB. Dated September 12, 2001 and docketed October 2, 2001.

CEC (California Energy Commission) / John Kessler 2001g. Report of Conversation with Steven Bayley, Deputy Director of Public Works, City of Tracy. Dated September 13, 2001 and docketed October 2, 2001.

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CVRWQCB (Central Valley Regional Water Quality Control Board) 2002a. Report of Conversation between Patricia Leary – CVRWQCB and John Kessler – CEC, dated June 10, 2002.

DWR (California State Department of Water Resources) 2002a. Letter from DWR to BBID dated June 19, 2002 transmitting Draft Agreement Between DWR and BBID Regarding the Diversion of Water From the Delta. Docketed July 9, 2002.

DWR (California Department of Water Resources/Dan Flory) 2002b. Remaining issues associated with the agreement between DWR and BBID. Dated 7/9/02 and docketed 7/9/02.

DWR (California Department of Water Resources) 2002e, Draft SWP Delivery Reliability Report, dated August 20, 2002.

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.

DWR (California Department of Water Resources) 2002c, California Water Plan Update 1998.

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EAEC (East Altamont Energy Center) 2001e. Data Adequacy Response Set 1. Dated and docketed May 1, 2001.

EAEC (East Altamont Energy Center) 2001f. Data Adequacy Response Set 2. Dated and docketed May 3, 2001.

EAEC (East Altamont Energy Center) 2001g. Supplement A to the East Altamont Energy Center (01-AFC-4). Dated and docketed May 3, 2001.

EAEC (East Altamont Energy Center) 2001i. Data Adequacy Response Set 3. Dated and docketed May 7, 2001.

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EAEC (East Altamont Energy Center) 2001n. Data Request Response Set #1. Dated July 9, 2001 and docketed July 10, 2001.

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Mountain House Community Services District (MHCSD)/ Paul Sensibaugh 2002b. Response to CEC Staff inquiries regarding recycled water from MHCSD. Dated 6/20/02 and docketed 6/25/02.

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SWRCB (State Water Resources Control Board) 1998, Exhibit A, Water Right Order 98-08, Declaration of Fully Appropriated Stream Systems, November 19, 1998.

WORKER SAFETY AND FIRE PROTECTION

Testimony of Alvin J. Greenberg, Ph.D. and Rick Tyler

INTRODUCTION

Worker safety and fire protection is regulated based on 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, doing business as 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 (OSH Act). This Act mandates safety requirements in the workplace and is found in Title 29 of the United States Code, sections 651 through 678. Implementing regulations are codified at Title 29 of the Code of Federal Regulations, under General Industry Standards sections 1910.1 through 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); and

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 Title 29 of the Code of Federal Regulations, sections 1910.1 – 1910.1500 and sections 1952.170 – 1952.175.

STATE

California passed the Occupational Safety and Health Act of 1973 ("Cal/OSHA") as codified in the California Labor Code, section 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 through 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 Title 29 of the California Code of Regulations, sections 1910.1 through 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 and contained in Title 8 of the California Code of Regulations, section 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 Prevention 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; and

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 Title 24 of the California Code of Regulations (Health and Safety Code § 18901 et seq.).

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.; and

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, Alameda 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. The relocation will commence as soon as possible and will be completed prior to the start of operations of the EAEC (ACFD 2002b,c). 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).

Staff has reviewed and evaluated the adequacy of the response time by the ACFD both with and without the relocation of station 8. Staff notes that the response time would vary from 10 minutes to as long as 30 minutes due to traffic and yet is consistent with times found to be adequate at other rural power plant locations within California. Rural response times are necessarily longer than urban response times due to distance between population centers where fire stations are usually located. Staff also notes the existence of mutual aid agreements between fire fighting jurisdictions whereby the nearest station may be within another jurisdiction. Mutual aid agreements require the nearest station to respond first on-scene, evaluate the situation, begin operations as appropriate, and then relinquish command and control to the fire-fighting team from the jurisdictional department upon their arrival. In the event that fire fighting services were needed at the proposed facility, the existing agreement between City of Tracy Fire Department and the Alameda County fire department would likely result in a first response from the new Mountain House Community Services District Fire Department.

Alameda County Fire Department would then arrive on-scene minutes later and assume command and control of the situation.

At the May 28, 2002 workshop, the City of Tracy Fire Department expressed concerns about serving the EAEC with fire and emergency services (EMS), which they would be obligated to do under their current Mutual Aid Agreement with Alameda County Fire Department. According to staff's analysis, however, power plants in general rarely require off-site fire fighting response. This is because of the lack of burnable materials at a power plant, the safety precautions taken, the training of the on-site workers, and the presence of on-site automatic fire detection and suppression systems. Furthermore, the need for EMS response is also minimal. This fact is documented by the applicant's survey of requests from several of its power plants in the western region for off-site fire fighting and EMS services (EAEC 2002lll). The applicant found that for 13 power plants over the past 10 years, only two (2) fire responses were requested, none for a major incident. During this same period, a total of five (5) EMS requests were made and only one of those was for a work-related injury. This supports staff's understanding that off-site fire and EMS services are rarely requested or needed at power plants. Staff therefore concludes that, if the Tracy Fire Department or the Mountain House Community Services District continue to provide services to Alameda County under the current mutual aid agreement, the resulting impacts from the EAEC on those fire departments would be insignificant.

Staff also finds that even without the existence of a Mutual Aid Agreement, fire-fighting and EMS response times for this project are no greater (and in some places far less) than for other California rural power plants, and thus would be sufficient to service the EAEC. Staff therefore concludes that, even without a mutual aid agreement, there will not be significant impacts.

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 other existing and foreseeable industrial facilities and the proposed Mountain House Community, to result in impacts on the fire and emergency service capabilities of the Alameda County Fire Department and found that cumulative impacts were insignificant. The most likely need for service at the proposed facility would involve an EMS response. The proposed facility would not significantly increase the frequency of EMS responses in Alameda County. It is also unlikely that the new Mountain House Community would be impacted by providing infrequent EMS or fire responses. The new Mountain House Community development is in a different county and fire protection services would be funded as a result of the community development. The need for additional equipment, staffing, or funding has been made by the Alameda County Fire Department in personal communications, correspondence, or in workshops. This need has been addressed by the applicant. Other power plant projects proposed for this same general area do not change this conclusion.

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 data request, the Applicant has stated that project operations staff will be thoroughly trained to respond to a small fire, activate fire suppression systems, or notify the off-site fire department (EAEC 2001v, page 22). 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. 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.

AGENCY COMMENTS

Alameda County Fire Department

Comment 1 *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, including the UFC and the NFPA. 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.

Comment 2 *The Alameda County Fire Department stated in a letter dated January 30, 2002 that they are the jurisdiction with responsibility for fire response to the EAEC and not the MHCSD.*

Response: Staff agrees that the EAEC is within the jurisdiction of the Alameda County Fire Department and that this department has first-responder responsibilities. Please also see response above.

California Department of Industrial Relations, Division of Occupational Safety and Health

Comment *Senior Safety Engineer Roy 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.

Mountain House Community Services District

Comment *The Mountain House Community Services District (MHCSD) states in a letter dated December 14, 2001 that their new proposed fire station would be the first responder to any incidents at the EAEC and requests that Calpine pay its fair share of the fire protection that will be provided.*

Response: It is staff's conclusion from personal communications with both the MHCSD and the Alameda County Fire Department and from comments made at a public workshop that this position is incorrect. MHCSD is part of the Tracy Fire Department, which is in a mutual aid agreement with Alameda County Fire Department. However, this does not mean that the MHCSD is the first responder; indeed, the Tracy Fire Department would offer aid and assistance only upon the request of the Alameda County Fire Department. The proposed EAEC is located in Alameda County. Therefore, it is within the jurisdiction of the *Alameda County Fire Department, which would be the first responder to any incident at the EAEC.*

City of Tracy Fire Department

Comment *The City of Tracy Fire Department states in a letter dated June 10, 2002 that, since the Alameda County Fire Department wishes to have full responsibility for response to the entire Alameda County area (which includes the proposed EAEC), they will consider terminating the current mutual aid agreement.*

> Response: Staff recognizes that the Tracy Fire Department believes that the current Mutual Aid Agreement between it and the Alameda County Fire Department is unbalanced with regard to services provided by each department. A failure of the Tracy Fire Department or the future fire department of the Mountain House Community Services District to honor a mutual aid agreement is thus theoretically possible. However, staff finds that the need for off-site fire fighting response at power plants is minimal due to the lack of burnable materials at a power plant, the safety precautions taken, the training of the on-site workers, and the presence of on-site automatic fire detection and suppression systems. Furthermore, the need for EMS response is also minimal. This fact is documented by the applicant's survey of requests from several of its power plants in the western region for off-site fire and EMS services (EAEC 2002lll). The applicant found that for 13 power plants over the past 10 years, only two (2) fire responses were requested, none for a major incident. During this same period, a total of five (5) EMS requests were made and only one of those was for a work-related injury. Staff finds that off-site fire and EMS services are rarely requested or needed at power plants and thus no significant impact would exist on either the Tracy Fire Department or the Mountain House Community Services District should either honor a Mutual Aid Agreement. Even without the existence of a Mutual Aid Agreement, fire-fighting and EMS response times for this project would be no greater, and in some places far less, than for other California rural power plants.

PUBLIC COMMENTS

SMS-1 *Ms. Sarvey expressed concern that the EAEC project would add more fire risk and more responsibility to an "overburdened" fire department. She stated that fires are also terrible for air quality, and requested that EAEC should have to provide the Tracy FD with an additional fire truck to ensure public safety and health, and air quality in Tracy.*

> Response: Please refer to staff's response to the Tracy Fire Department (above).

IKS-1 *Ms. Sundberg commented that the Tracy Fire Department responds 30% of the time to fires in Alameda County because of their closer proximity. Acceptable mitigation would be a fire truck and station for all the power companies to share the cost.*

> Response: Please refer to staff's response to the Tracy Fire Department (above).

CD-1 *Ms. Dominguez commented that Tracy trucks respond to Altamont fires leaving the city at risk and without adequate coverage, and requested negotiation on their fire services.*

Response: Please refer to staff's response to the Tracy Fire Department (above).

BGH-1 *Ms. Hooper commented that Tracy needs a fully equipped fire station. She also commented that the deaf should be included in public notification process of problems with these 3 plants coming on line in the area.*

Response: Please refer to staff's response to the Tracy Fire Department (above). In regards to public notification of deaf persons, all public notices will be in writing. In regards to emergency notices, the applicant must prepare and submit a Hazardous Materials Business Plan and a Risk Management Plan, both of which must contain information about public notification of emergencies. Staff feels that the American Disabilities Act requires that these notifications be in an appropriate format so as to inform and warn all members of the community. The CPM will review and approve these plans prior to the introduction of hazardous materials on-site.

JMH-1 *Mr. Hooper commented that the residents of Tracy want a fully equipped fire station that services the 3 electrical plants only. He also commented that TTY's should be used in public services areas so the hearing impaired can be notified of emergencies.*

Response: Please refer to staff's response to the Tracy Fire Department (above) and the response to Ms. Hooper (above).

CHH-1 *Ms. Hariton commented that fire protection is needed in Tracy, and that another fire station is a necessity.*

Response: Please refer to staff's response to the Tracy Fire Department (above).

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 Alameda County Fire Department. This department has expressed a need for modification of its existing infrastructure to serve this power plant and this need has been addressed by the applicant. The fire risks of the proposed facility do not pose significant added demands on local fire protection services and the fire-fighting and EMS response times are no greater than for other rural California power plants.

If the Energy Commission certifies the project, staff recommends that the Energy 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 Energy Commission Compliance Project Manager (CPM) a copy of the Project Construction Safety and Health Program containing the following:

A Construction Injury and Illness Prevention 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 Illness and Injury Prevention Program, the Personal Protective Equipment Program, and the Exposure Monitoring Program shall be submitted to the CPM for review and approval 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 for approval.

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 and the 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;

A Hazardous Materials Management Program;

An Operations and Maintenance Safety Program;

A Fire Protection and Prevention Program (Cal Code Regs., tit. 8,§ 3221); and;

A 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 Alameda County Fire Department for review and comment.

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, if any, stating that they have reviewed and accepted the specified elements of the proposed Operations and Maintenance Safety and Health Plan. The project owner shall provide a letter from the Alameda County Fire Department stating that they have reviewed and commented on the Operations Fire Protection and Prevention Plan and the Emergency Action 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.

Alameda County Fire Department (ACFD). 2002a. Personal communication with Fire Chief William McCammon. March 5, 2002.

Alameda County Fire Department (ACFD). 2002b. Personal communication with Fire Chief William McCammon. June 2002.

Alameda County Fire Department (ACFD). 2002c. Statement of Assistant Chief Ferdinand at May 28, 2002 staff workshop.

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.

City of Tracy Fire Department (COTFD)/ Terrel Estes 2002a. Letter from Terrell S. Estes, Fire Chief, City of Tracy Fire Department to William J. McCammon, Fire Chief, Alameda County Fire Department. Dated 6/10/02 and docketed 6/12/02.

EAEC (East Altamont Energy Center) 2002lll. Informal Response to Request for Data. Dated and docketed July 3, 2002.

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.

Mountain House Community Service District (MHCSD). 2001a. Personal communication with General Manager Paul Sensibaugh. December 28, 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.

FACILITY DESIGN

Testimony of 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 engineering LORS and any special design requirements.

FINDINGS REQUIRED

The Warren Alquist Act requires the Energy 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). Staff has conducted the following analysis in order to assist the Commission in making the required findings.

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 820 megawatt (MW) nominal, natural gas fired, combined cycle power plant augmented by 245 MW of duct firing. 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, and across Mountain House Road from, 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 1.8 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 and EAEC 2002b). 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 Welding Society (AWS).

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) 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 1.8 mile natural gas pipeline will be constructed to provide fuel to the proposed facility. This pipeline may be owned by PG&E, the Applicant, or an affiliate of the Applicant. 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 permit fees are paid by the applicant consistent with CBC Section 107, to cover the costs of reviews and inspections.

Engineering and compliance staff will invite the local building authority, either the City or the 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 in the record, and concludes that the design, construction and eventual closure of the project are likely to 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 review the final designs, conduct plan checking and perform field inspections during construction, and Energy Commission staff 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 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 project owner and CBO approved alternative timeframe) 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, static motor starter, 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 Air Plenum and Filter Structure, Foundation and Connections	3
CT Inlet Air Evaporative Cooler 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 (ST) Foundation and Connections	1
ST Structure Shell and Façade Foundation and Connections	1
Steam Turbine Generator (STG) Foundation and Connections	1
STG Lube Oil Skid Foundation and Connections	1
STG Hydraulic Control System Foundation and Connections	1

Equipment/System	Quantity (Plant)
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
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
Electrical Control Centers, Switchgear and Switchyard Equipment Foundations 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, De-Mineralized Water Treatment Building, Mechanical Shop, Fire Pump Building, Fuel Gas Compressor Building, Compressor Building, Switchyard Control Building, Boiler Feed Pump Building, etc.)	1 Lot
Skid – Amonia Blower Injection Foundation and Connections	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

Equipment/System	Quantity (Plant)
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 Scavenger, Amine, Phosphate, etc.) Foundation and Connections (as required by CBC)	1 Lot
Cooling Tower/Air Cooled Condenser Structure, Foundation and Connections	1 Lot
Boiler – Auxiliary, Stack, Foundation and Connections	1
Auxiliary Boiler SCR System Foundation and Connections	1 Lot
Ammonia Injection Skid Foundation and Connections	1 Lot
Compressors – Air Foundation(s) and Connections	1 Lot
Compressors – Fuel Gas Foundation(s) and Connections	1 Lot
Pipeline – Water Supply	1
Pipeline – Recycled Water Supply	1
Pipeline – Natural Gas	1
Potable Water Systems	1 Lot
Chemical Containment 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 project owner and CBO approved alternative timeframe) prior to the start of rough grading, the project owner shall submit to the CBO for review and approval, the resume and registration number of the RE and any other delegated engineers assigned to the project. The project owner shall notify the CPM of the CBO's approvals of the RE and other delegated engineer(s) within five days of the approval.

If the RE or the delegated engineer(s) are subsequently reassigned or replaced, the project owner has five days in which to submit the resume and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer within five days of the approval.

GEN-5 Prior to the start of construction, the project owner shall assign at least one of each of the following California registered engineers to the project: A) 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.

<u>Protocol:</u> 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.

<u>Protocol:</u> 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 engineering 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 project owner and CBO approved alternative timeframe) prior to the start of rough grading, the project owner shall submit to the CBO for review and approval, the resumes 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 resume and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer within five days of the approval.

GEN-6 Prior to the start of an activity requiring special inspection, 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 [1998 CBC, Chapter 17, Section 1701.3, Duties and Responsibilities of the Special Inspector]; 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 (or project owner and CBO approved alternative timeframe) prior to the start of an activity requiring special inspection, the project owner shall submit to the CBO for review and approval, with a copy to the CPM, the name(s) and qualifications of the certified weld inspector(s), or other certified special inspector(s) assigned to the project to perform one or more of the duties set forth above. The project owner shall also submit to the CPM a copy of the CBO's approval of the qualifications of all special inspectors in the next Monthly Compliance Report.

If the special inspector is subsequently reassigned or replaced, the project owner has five days in which to submit the name and qualifications of the newly assigned special inspector to the CBO for approval. The project owner shall notify the CPM of the CBO's approval of the newly assigned inspector within five days of the approval.

GEN-7 If any discrepancy in design and/or construction is discovered in any engineering work that has undergone CBO design review and approval, the project owner shall document the discrepancy and recommend the corrective action required [1998 CBC, Chapter 1, Section 108.4, Approval Required; Chapter 17, Section 1701.3, Duties and Responsibilities of the Special Inspector; and Appendix Chapter 33, Section 3317.7, Notification of Noncompliance]. 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 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 (or project owner and CBO approved alternative timeframe) prior to the start of site grading, the project owner shall submit the documents described above to the CBO for design review and approval. In the next Monthly Compliance Report following the CBO's approval, the project owner shall submit a written statement certifying that the documents have been approved by the CBO.

CIVIL-2 The resident engineer shall, if appropriate, stop all 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 24 hours, when earthwork and construction is stopped as a result of unforeseen adverse geologic/soil conditions. Within 24 hours of the CBO's approval to resume earthwork and construction in the affected areas, the project owner shall provide to the CPM a copy of the CBO's approval.

CIVIL-3 The project owner shall perform inspections in accordance with the 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 [1998 CBC, Appendix Chapter 33, Section 3317.7, Notification of Noncompliance]. 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 project owner and CBO approved alternative timeframe) prior to the start of any increment of construction of any structure or component listed in **Table 1** of Condition of Certification **GEN-2** above, 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 engineering LORS.

STRUC-2 The project owner shall submit to the CBO the required number of sets of the following documents related to work that has undergone CBO design review and approval:

1. Concrete cylinder strength test reports (including date of testing, date sample taken, design concrete strength, tested cylinder strength, age of test, type and size of sample, location and quantity of concrete placement from which sample was taken, and mix design designation and parameters);
2. Concrete pour sign-off sheets;
3. Bolt torque inspection reports (including location of test, date, bolt size, and recorded torques);
4. Field weld inspection reports (including type of weld, location of weld, inspection of non-destructive testing (NDT) procedure and results, welder qualifications, certifications, qualified procedure description or number (ref: AWS); and

5. Reports covering other structural activities requiring special inspections shall be in accordance with the 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 [1998 CBC, Chapter 17, Section 1701.3, Duties and Responsibilities of the Special Inspector]. 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 project owner and CBO approved alternate timeframe) prior to the start of installation of the tanks or vessels containing the above specified quantities of toxic or hazardous materials, the project owner shall submit to the CBO for design review and approval final design plans, specifications, and calculations, including a copy of the signed and stamped engineer's certification.

The project owner shall send copies of the CBO approvals of plan checks to the CPM in the following Monthly Compliance Report. The project owner shall also transmit a copy of the CBO's inspection approvals to the CPM in the Monthly Compliance Report following completion of any inspection.

MECH-1 The project owner shall submit, for CBO design review and approval, the proposed final design, specifications and calculations for each plant major piping and plumbing system listed in 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.

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 project owner and CBO approved alternative timeframe) 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 project owner and CBO approved alternative timeframe) prior to the start of on-site fabrication or installation of any pressure vessel, the project owner shall submit to the CBO for design review and approval, the above listed documents, including a copy of the signed and stamped engineer's certification, with a copy of the transmittal letter to the CPM.

The project owner shall transmit to the CPM, in the Monthly Compliance Report following completion of any inspection, a copy of the transmittal letter conveying the CBO's and/or Cal-OSHA inspection approvals.

MECH-3 The project owner shall submit to the CBO for design review and approval the design plans, specifications, calculations and quality control procedures for any heating, ventilating, air conditioning (HVAC) or refrigeration system. Packaged HVAC systems, where used, shall be identified with the appropriate manufacturer's data sheets.

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 project owner and CBO approved alternative timeframe) 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:

1. short-circuit ratings of plant equipment;
2. ampacity of feeder cables;
3. voltage drop in feeder cables;
4. system grounding requirements;
5. coordination study calculations for fuses, circuit breakers and protective relay settings for the 13.8 kV, 4.16 kV and 480 V systems;
6. system grounding requirements; and
7. 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 project owner and CBO approved alternative timeframe) 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.

EAEC (East Altamont Energy Center) 2002a. PSA Comments Set 1. Dated and docketed January 14, 2002.

EAEC (East Altamont Energy Center) 2002b. Supplement to East Altamont Energy center Application for Certification. Dated and docketed February 6, 2002.

GEOLOGY AND PALEONTOLOGY

Testimony of Dr. Dal Hunter

INTRODUCTION

In the geology and paleontology section, staff 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 geological and paleontological resources or 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 are described 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, in part, protects paleontological resources from vandalism and unauthorized collection on federal land (PL 59-209; 16 United States Code section 431 *et seq*.; 34 Stat. 25). The National Environmental Policy Act of 1969, as amended, requires analysis of potential environmental impacts to important historic, cultural and natural aspects of our national heritage (United States Code, section 4321 et seq.; 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. The sections of Appendix G that are relevant to an analysis of Geology and Paleontology are as follows:

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 Assessment and Mitigation of Adverse Impacts to Non-Renewable Paleontologic Resources is a set of procedures and standards for assessing and mitigating impacts to vertebrate paleontological resources (Society of Vertebrate Paleontologists 1995). These guidelines were developed by a committee of the Society of Vertebrate Paleontologists (SVP), a national organization.

ENVIRONMENTAL SETTING

The East Altamont Energy Center (EAEC) is proposed to 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 would involve the design, construction and operation of an 820-megawatt (MW) natural-gas-fired combined-cycle generating plant, augmented by 267 MW of duct firing. Two new double-circuit 230-kV transmission lines, approximately 0.5 miles each, will connect the new switchyard to an existing 230-kV double-circuit transmission line that will be sectionalized to provide interconnections with Western's Tracy Substation and the Westley Substation. The new lines will be installed over agricultural land and Kelso and Mountain House Roads. New electrical equipment will also be installed within the existing boundaries of the Tracy and Westley substations. The new switchyard, ownership of which will be transferred to Western, will function as an extension of the Tracy Substation. Natural gas for the facility will be delivered via approximately 1.8 miles of new 20-inch pipeline that will connect to Pacific Gas and Electric's (PG&E) existing gas pipeline west of the site. Raw water for cooling tower and process makeup water will initially be supplied by Byron Bethany Irrigation District (BBID), probably via a 2.1-mile pipeline west of the site. Several alternate waterline routes are being considered, including two routes for future reclaimed water to be brought from east of the project. None of the alternates affect the conclusions of this evaluation.

The project site 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, low 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 three 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 [46 percent of the acceleration of gravity] (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 by implementation of proposed Condition of Certification **GEN-1 (FACILITY DESIGN)**. 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 project site is located directly adjacent to an area mapped as liquefaction hazard zone (Contra Costa County, 1996). The depth to ground water at the project is approximately 10 to 15 feet below existing grade. The Applicant has conducted a design-level geotechnical investigation of the EAEC site that includes a liquefaction analysis based on standard methodology (Kleinfelder, 2001). The analysis indicates only localized liquefaction potential with surface settlement of one-half inch or less. From this evaluation, staff concludes that liquefaction is not a significant concern for this 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. The project geotechnical investigation did not identify soils with hydrocompaction potential at this site (Kleinfelder, 2001).

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. The project geotechnical investigation did not identify subsidence potential at this site (Kleinfelder, 2001).

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. The project geotechnical investigation has identified a significant shrink-swell (expansion) hazard for lightly loaded foundations, floor slabs, and exterior flatwork and pavements. Three mitigation alternates are discussed in the report (Kleinfelder, 2001).

Conditions of Certification **GEN-1, GEN-5** and **CIVIL-1** (contained in the **FACILITY DESIGN** section) would 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. The project geotechnical investigation has verified that the slopes for evaporation and storage ponds to be constructed on this site will be stable at proposed slope ratios up to 3:1 (horz:vert) (Kleinfelder, 2001).

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 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). In addition to research at museums and universities, the project paleontologist made a site survey visit and paleontologic inventory, as part of his report. 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 nearest documented fossil locality is less than one-half mile west-southwest of the EAEC and is designated by the University of California, Berkley Museum of Paleontology as site UCMP V4801. Fossil bones of a mammoth and rodents were found at this site, in Quaternary alluvium, during construction of the Delta-Mendota Canal. 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 ensure that the applicant mitigates impacts upon paleontological resources to a less than significant level should they be encountered during construction, operation, or 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 EAEC site 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.

Stormwater 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. Soils are noted to have poor drainage.

The County of Alameda requires detention of the 100-year, 24-hour storm with discharge metered to less than or equal to the pre-development 10-year, 24-hour storm event. The applicant has calculated the total runoff from the 32.5-acre project paved area of the proposed EAEC site as approximately 10.46 acre-feet (3.41 million gallons) for the 100-year storm in 24 hours, and 3.01 acre-feet for the pre-development 10-year storm, again for a 24-hour period. The study provided by the applicant indicates that the post-construction runoff is 70 percent higher than the pre-construction storm water runoff for the 100-year event. (EAEC, 2001a).

Following construction, storm water will drain to a stormwater detention pond via a system of drains, channels, and pipes. Preliminary design indicates a detention pond about three acres in size and with a depth of three feet. 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 (Facility Design),** along with specific conditions presented under **Water Resources**, will 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, including its linear facilities. 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 have been found at the project site, although there is some documentation of a fossil site within one-half mile of the EAEC. Since there is to be considerable grading, Energy Commission staff believes there is at least a moderate probability of encountering paleontological resources. The confidential paleontological report submitted by the Applicant classified the geologic units in the site area as “highly sensitive.” The recommended Conditions of Certification **PAL-1 through PAL-7** will 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. There are a number of other electric power generating plants being considered in the area, including the Tesla, Tracy, and Mountain House projects. Any environmental impacts related to geology, mineral resources, paleontology, or surface water hydrology at the proposed EAEC would not be expected to be cumulative with impacts of other power projects. These projects are at least 5 miles to the south-southwest of the EAEC.

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. A facility closure plan will be developed prior to closure to ensure that no significant impacts occur as a result of closure activities.

RESPONSE TO PUBLIC AND AGENCY COMMENTS

Energy Commission staff received no comments regarding geology, paleontology or surface water from City, County, State, or Federal agencies. One comment from the public, designated as "G&DK-10" 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

CONCLUSIONS AND RECOMMENDATIONS

If built, the project, including linear facilities, would have no adverse impact on geological and paleontological resources and surface water hydrology. Staff proposes to assure compliance with applicable LORS for geological hazards, paleontological resources, and surface water hydrology, with implementation of 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.

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 The project owner shall provide the CPM with the resume and qualifications of its Paleontological Resource Specialist (PRS) and Paleontological Resource Monitors (PRMs) for review and approval. If the approved PRS or one of the PRMs is replaced prior to completion of project mitigation and report, the project owner shall obtain CPM approval of the replacement.

The resume shall include the names and phone numbers of contacts. The resume shall also demonstrate to the satisfaction of the CPM, the appropriate education and experience to accomplish the required paleontological resource tasks.

As determined by the CPM, the PRS shall meet the minimum qualifications for a vertebrate paleontologist as described in the Society of Vertebrate Paleontologists (SVP) guidelines of 1995. The experience of the PRS shall include the following:

1) institutional affiliations or appropriate credentials and college degree;
2) ability to recognize and recover fossils in the field;
3) local geological and biostratigraphic expertise;
4) proficiency in identifying vertebrate and invertebrate fossils;
5) publications in scientific journals; and
6) the PRS shall have at least three years of paleontological resource mitigation and field experience in California, and at least one year of experience leading paleontological resource mitigation and field activities.

The PRS shall obtain qualified paleontological resource monitors to monitor as necessary on the project. Paleontologic resource monitors (PRMs) shall have the equivalent of the following qualifications:

1) BS or BA degree in geology or paleontology and one year experience monitoring in California; or
2) AS or AA in geology, paleontology or biology and four years experience monitoring in California; or
3) Enrollment in upper division classes pursuing a degree in the fields of geology or paleontology and two years of monitoring experience in California.

Verification: At least 60 days prior to the start of ground disturbance, the project owner shall submit a resume and statement of availability of its designated PRS for on-site work.

At least 20 days prior to ground disturbance, the PRS or project owner shall provide a letter with resumes naming anticipated monitors for the project and stating that the identified monitors meet the minimum qualifications for paleontological resource monitoring required by the condition. If additional monitors are obtained during the project, the PRS shall provide additional letters and resumes to the CPM for approval. The letter shall be provided to the CPM no later than one week prior to the monitor beginning on-site duties.

Prior to the termination or release of a PRS, the project owner shall submit the resume of the proposed new PRS to the CPM for review and approval.

PAL-2 The project owner shall provide to the PRS and the CPM, for approval, maps and drawings showing the footprint of the power plant and all linear facilities. Maps shall identify all areas of the project where ground disturbance is anticipated. If the PRS requests enlargements or strip maps for linear facility routes, the project owner shall provide copies to the PRS and CPM. The site grading plan and the plan and profile drawings for the utility lines would normally be acceptable for this purpose. The plan drawings should show the location, depth, and extent of all ground disturbances and can be 1 inch = 40 feet to 1 inch = 100 feet range. If the footprint of the power plant or linear facility changes, the project owner shall provide maps and drawings reflecting these changes to the PRS and CPM.

If construction of the project will proceed in phases, maps and drawings may be submitted prior to the start of each phase. A letter identifying the proposed schedule of each project phase shall be provided to the PRS and CPM. Prior to work commencing on affected phases, the project owner shall notify the PRS and CPM of any construction phase scheduling changes.

At a minimum, the PRS 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.

<u>**Verification:**</u> At least 30 days prior to the start of ground disturbance, the project owner shall provide the maps and drawings.

If there are changes to the footprint of the project, revised maps and drawings shall be provided at least 15 days prior to the start of ground disturbance.

If there are changes to the scheduling of the construction phases, the project owner shall submit a letter to the CPM within 5 days of identifying the changes.

PAL-3 The PRS shall prepare, and the project owner shall submit to the CPM for review and approval, a Paleontological Resources Monitoring and Mitigation Plan (PRMMP) to identify general and specific measures to minimize potential impacts to significant paleontological resources. Approval of the PRMMP by the CPM shall occur prior to any ground disturbance. The PRMMP shall function as the formal guide for monitoring, collecting and sampling activities and may be modified with CPM approval. This document shall be used as a basis for discussion in the event that on-site decisions or changes are proposed. Copies of the PRMMP shall reside with the PRS, each monitor, the project owner's on-site manager, and the CPM.

The PRMMP shall be developed in accordance with the guidelines of the Society of the Vertebrate Paleontologists (SVP, 1995) and shall include, but not be limited to, the following:

1) Assurance that the performance and sequence of project-related tasks, such as any literature searches, pre-construction surveys, worker environmental training, fieldwork, flagging or staking; construction monitoring; mapping and data recovery; fossil preparation and recovery; identification and inventory; preparation of final reports; and transmittal of materials for curation will be performed according to the PRMMP procedures;
2) Identification of the person(s) expected to assist with each of the tasks identified within the PRMMP and all conditions for certification;
3) A thorough discussion of the anticipated geologic units expected to be encountered, the location and depth of the units relative to the project when known, and the known sensitivity of those units based on the occurrence of fossils either in that unit or in correlative units;
4) An explanation of why, how, and how much sampling is expected to take place and in what units. Include descriptions of different sampling procedures that shall be used for fine-grained and coarse-grained beds;
5) A discussion of the locations of where the monitoring of project construction activities is deemed necessary, and a proposed schedule for the monitoring;
6) A discussion of the procedures to be followed in the event of a significant fossil discovery, including notifications;
7) 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;
8) Procedures for 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;
9) Identification of the institution that has agreed to receive any data and fossil materials recovered, requirements or specifications for materials delivered for curation and how they will be met, and the name and phone number of the contact person at the institution; and
10) A copy of the paleontological conditions of certification.

Verification: At least thirty (30) days prior to ground disturbance, the project owner shall provide a copy of the PRMMP. The PRMMP shall include an affidavit of authorship by the PRS, and acceptance of the project owner evidenced by a signature

PAL-4 Prior to ground disturbance and for the duration of construction, the project owner and the PRS shall prepare and conduct weekly CPM-approved training for all project managers, construction supervisors and workers who operate ground disturbing equipment or tools. Workers to be involved in ground disturbing activities in sensitive units shall not operate equipment prior to receiving worker training. The training program may be combined with other training programs prepared for cultural and biological resources, hazardous materials, or any other areas of interest or concern.

The Worker Environmental Awareness Program (WEAP) shall address 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. In-person training shall be provided for each new employee involved with ground disturbing activities, while these activities are occurring in highly sensitive geologic units, as detailed in the PRMMP. The in-person training shall occur within four days following a new hire for highly sensitive sites and as established by the PRMMP for sites of moderate, low, and zero sensitivity. Provisions will be made to provide the WEAP training to workers not fluent in English.

The training shall include:

1) A discussion of applicable laws and penalties under the law;
2) For training in locations of high sensitivity, the PRS shall provide good quality photographs or physical examples of vertebrate fossils that may be expected in the area;
3) Information that the PRS or PRM has the authority to halt or redirect construction in the event of a discovery or unanticipated impact to a paleontological resource;
4) Instruction that employees are to halt or redirect work in the vicinity of a find and to contact their supervisor and the PRS or PRM;
5) An informational brochure that identifies reporting procedures in the event of a discovery;
6) A Certification of Completion of WEAP form signed by each worker indicating that they have received the training; and
7) A sticker that 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 submit the proposed WEAP including the brochure with the set of reporting procedures the workers are to follow.

At least 30 days prior to ground disturbance, the project owner shall submit the script and final video to the CPM for approval if the project owner is planning on using a video for interim training.

If an alternate paleontological trainer is requested by the owner, the resume and qualifications of the trainer shall be submitted to the CPM for review and approval. Alternate trainers shall not conduct training prior to CPM authorization.
The project owner shall provide in the Monthly Compliance Report the WEAP copies of the Certification of Completion forms with the names of those trained and the trainer for each training offered that month. The Monthly Compliance Report shall also include a running total of all persons who have completed the training to date.

PAL-5 The PRS and PRM(s) shall monitor consistent with the PRMMP, all construction-related grading, excavation, trenching, and augering in areas where potentially fossil-bearing materials have been identified. In the event that the PRS determines full time monitoring is not necessary in locations that were identified as potentially fossil-bearing in the PRMMP, the PRS shall notify and seek the concurrence of the CPM.

The PRS and PRM(s) shall have the authority to halt or redirect construction if paleontological resources are encountered. The project owner shall ensure that there is no interference with monitoring activities unless directed by the PRS. Monitoring activities shall be conducted as follows:

1) Any change of monitoring different from the accepted schedule presented in the PRMMP shall be proposed in a letter from the PRS and the project owner to the CPM prior to the change in monitoring. The letter shall include the justification for the change in monitoring and submitted to the CPM for review and approval.
2) PRM(s) shall keep a daily log of monitoring of paleontological resource activities. The PRS may informally discuss paleontological resource monitoring and mitigation activities with the CPM at any time.
3) The PRS shall immediately notify the project owner and the CPM of any incidents of non-compliance with any paleontological resources conditions of certification. The PRS shall recommend corrective action to resolve the issues or achieve compliance with the conditions of certification.
4) For any significant paleontological resources encountered, either the project owner or the PRS shall notify the CPM immediately (no later than the following morning after the find, or Monday morning in the case of a weekend) of any halt of construction activities.

The PRS shall prepare a summary of the monitoring and other paleontological activities that will be placed in the Monthly Compliance Reports. The summary will include the name(s) of PRS or monitor(s) active during the month; general descriptions of training and construction activities and general locations of excavations, grading, etc. A section of the report will include the geologic units or subunits encountered; descriptions of sampling within each unit; and a list of fossils identified in the field. A final section of the report will address any issues or concerns about the project relating to paleontologic monitoring including any incidents of non-compliance and any changes to the monitoring plan that have been approved by the CPM. If no monitoring took place during the month, the project shall include a justification in summary as to why monitoring was not conducted.

Verification: The PRS shall submit the summary of monitoring and paleontological activities in the Monthly Compliance Report.

PAL-6 The project owner, through the designated PRS, 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 their compliance file copies of signed contracts or agreements with the designated PRS and other qualified research specialists. The project owner shall maintain these files for a period of three years after completion and approval of the CPM-approved PRR. The project owner shall be responsible to pay curation fees for fossils collected and curated as a result of paleontological monitoring and mitigation.

PAL-7 The project owner shall ensure preparation of a Paleontological Resources Report (PRR) by the designated PRS. The PRR shall be prepared following completion of the ground disturbing activities. The PRR shall include an analysis of the recovered fossil materials and related information and submitted to the CPM for review and approval.

The report shall include, but not be limited to, a description and inventory of recovered fossil materials; a map showing the location of paleontological resources encountered; determinations of sensitivity and significance; and a statement by the PRS that project impacts to paleontological resources have been mitigated.

Verification: Within ninety (90) days after completion of ground disturbing activities, including landscaping, the project owner shall submit the Paleontological Resources Report under confidential cover.

Certification of Completion of Worker Environmental Awareness Program EAST ALTAMONT ENERGY CENTER (01-AFC-4)

This is to certify these individuals have completed a mandatory California Energy Commission-approved Worker Environmental Awareness Program (WEAP). The WEAP includes pertinent information on Cultural, Paleontology & Biology Resources for all personnel (i.e. construction supervisors, crews and plant operators) working on-site or at related facilities. By signing below, the participant indicates that they understand and shall abide by the guidelines set forth in the Program materials. Please include this completed form in your Monthly Compliance Report.

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Cul Trainer: ________________ Signature:__________________________ Date: ___/___/____

PaleoTrainer: ________________ Signature:__________________________ Date: ___/___/____

Bio Trainer: ________________ Signature:__________________________ Date: ___/___/____

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POWER PLANT RELIABILITY

Testimony of Shahab Khoshmashrab and 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 peaking capacity of up to 269 MW, 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 the plant up to 8,760 hours per year with the incremental peaking capacity operated for 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;

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.

On the other hand, CaISO is not overly concerned with the EAEC project due to its remote location (Miller 2002). CaISO typically plans for a single system loss of 1,150 MW, their chief concern being a system stability problem from failure of a plant. This concern arises mainly where local area benefits are a question, as at Potrero in San Francisco, where the loss of only 500 MW from a single failure is a concern.

To minimize the likelihood of failure, the EAEC steam turbine will have two dual flow low pressure sections. Because of this, the turbine will have two surface condensers. The most common failure mode for the surface condensers is a tube leak, where circulating water leaks into the condensate, thus contaminating the condensate (EAEC 2001hh). To avoid the necessity of tripping the steam turbine because of a condenser leak, the applicant will utilize condensers with divided water boxes. This feature allows one-half of the condenser to be taken out of service to repair tube leaks while the other half continues to operate. The benefit of this design is that the steam turbine continues to operate, generating a large amount of its full-load output. Also, because the EAEC is a zero liquid discharge facility, the condensers will be constructed of titanium. The welded joints and superior corrosion resistance of the titanium condensers should result in fewer tube leaks than condensers fabricated of standard materials.

The circulating water piping will be concrete with welded steel joints. Thus, the potential for leaks in the circulating water piping will be extremely low.

The cooling tower for the EAEC will contain 19 cells. Provisions will be included to allow each cell to be individually isolated in the event of a fan, motor or gearbox failure (EAEC 2001hh). With 18 cells working, the cooling tower will be capable of operating at more than 95 percent of its design capacity. The cooling tower basin for the EAEC will be constructed such that approximately one-half of the basin can be taken out of service while the other half continues to operate. Typically, the cooling tower basin will be cleaned during plant outages. However, this feature will allow half the cooling tower to be taken out of service without tripping the steam turbine in the event that the basin needs to be cleaned between outages. With only half of the cooling tower in operation, the steam turbine will be capable of generating more than half of its maximum output (EAEC 2001hh).

The EAEC will use two 50-percent circulating water pumps. If one pump were to fail, the other pump would "run out" further on its curve, pumping much more than 50-percent of the total design flow, thus allowing the steam turbine to generate two thirds of its maximum output (EAEC 2001hh).

With the opportunity for continued operation in the face of equipment failure, staff believes that equipment redundancy would be sufficient for a project such as this.

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; EAEC 2002n, p. 2). 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 62 percent by year 2024 (EAEC 2001a, AFC §§ 1.1, 1.5.2, 7.0, 8.14, 10.2.2, Table 7-1B). 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.

Note that the applicant proposes to take all customary measures to maximize the reliability of the condenser and cooling system, 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 can be expected to be adequately reliable, in line with industry norms.

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. (Note that the applicant estimates potential revenue losses approaching $10 million per year if dry cooling is employed (EAEC 2002a). Staff does not purport to address the economics of a switch to dry cooling.)

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 RECOMMENDATION

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. CaISO has stated that it can plan around a plant failure of up to 1,150 MW (Miller 2002). The applicant proposes to take all customary measures to maximize the reliability of the condenser and cooling system in order to minimize the possibility of total plant failure (EAEC 2001hh). Therefore, staff is not overly concerned about a single failure of the condenser or the cooling system.

Staff concludes that the plant will be built and operated in a manner consistent with industry norms for reliable operation. This should provide an adequate level of reliability. No Conditions of Certification are proposed.

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TRANSMISSION SYSTEM ENGINEERING

Testimony of Ajoy Guha, P. E. and Al McCuen

INTRODUCTION

The Transmission System Engineering (TSE) analysis provides the basis for the findings in the Energy Commission's decision. Through this analysis staff determines 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 and whether or not the applicant has accurately identified all interconnection facilities required for addition of the project to the electric grid.

Staff evaluated 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.

Additionally, under the California Environmental Quality Act (CEQA), the Energy Commission must conduct an environmental review of the "whole of the action," which may include facilities not licensed by the Energy Commission (California Code of Regulations, title 14, §15378). Therefore, the Energy Commission must identify 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. This includes the facilities 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.

Calpine, doing business as East Altamont Energy Center, LLC (applicant) filed an Application for Certification with the California Energy Commission to construct an 820 megawatt (MW) natural gas-fired combined cycle plant which is proposed to be augmented with 250 MW of duct burning for a total 1,070 MW generating capacity 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 (see Definition of Terms) transmission (EAEC 2001a, AFC pages 1-1 to 1-3, 5-1). The plant could be on-line by the summer of 2005. 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.

SUMMARY OF CONCLUSIONS

1. The proposed EAEC power plant switchyard, outlet lines, and termination are adequate, in accordance with good utility practices and are acceptable to staff. These facilities would be designed, owned and operated by Western. Either Western or the applicant would build these facilities. If the applicant builds the facilities, the construction would be according to Western design and specifications and as such would be done under the supervision of Western. With implementation of the conditions of certification recommended by staff, these facilities will comply with LORS.
2. The System Impact Studies performed by Western and PG&E reveal that the interconnection of the EAEC project would have some adverse impacts on the transmission system. There would be overload criteria violations in several transmission facilities of the Western, PG&E, SMUD and MID systems under normal and emergency conditions of the electrical grid. However, most of these overload violations are due to aggravation of the already existing pre-project overloads. The mitigation measures proposed will be effective in eliminating the adverse impacts 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 and underground lines. Compliance with these orders 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.

California Public Utilities Commission (CPUC) General Order 128(GO-128), "Rules for Construction of Underground Electric Supply and Communications Systems," formulates uniform requirements and minimum standards to be used for underground supply systems to ensure adequate service and safety to persons engaged in the construction, maintenance and operation or use of underground electric lines and to the public in general.

Western "General Requirements for Interconnection," September 1999, provides Western's general minimum requirements including technical, environmental and contractual requirements for interconnection, additions and modifications to Western's transmission facilities.

The National Electric Safety Code, 1999 provides electrical, mechanical, civil and structural requirements for overhead electric line construction and operation.

The North American Electric Reliability Council (NERC) and Western Systems Coordinating Council (WSCC) Planning Standards were merged. The combined Planning Standards are now referred to as the NERC/WSCC Planning Standards and provide the system performance standards used in assessing the reliability of the interconnected system. Certain aspects of the NERC/WSCC standards are either more stringent or more specific than the NERC standards. These standards provide guidance for planning electric systems so as to withstand the more probable forced and maintenance outage system contingencies at projected customer demand and anticipated electricity transfer levels, while continuing to operate reliably within equipment and electric system thermal, voltage and stability limits. These standards include the reliability criteria for system adequacy and security, system modeling data requirements, system protection and control, and system restoration. Analysis of the WSCC system is based to a large degree on Section I.A of the standards, “NERC and WSCC Planning Standards with Table I and WSCC Disturbance-Performance Table” and on Section I.D, “NERC and WSCC Standards for Voltage support and Reactive Power.” These standards require that the results of power flow and stability simulations meet defined performance levels. Performance levels are defined by specifying the allowable variations in thermal loading, voltage and frequency, 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 levels designed 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 or load or system separation is permitted in certain circumstances, their uncontrolled loss is not permitted (WSCC 2001).

NERC Planning Standards provide national policies, standards, principles and guidelines to assure the adequacy and security of the electric transmission system. The NERC planning standards provide for system performance levels under normal and contingency conditions. With regard to power flow and stability simulations, while these Planning Standards are similar to WSCC Standards, certain aspects of the WSCC standards are either more stringent or more specific than the NERC standards for Transmission System Contingency Performance. The NERC planning standards apply not only to interconnected system operation but also to individual service areas (NERC 1998).

Cal-ISO Grid Planning Standards also provide standards, and guidelines to assure the adequacy, security and reliability in the planning of the Cal-ISO transmission grid facilities. The Cal-ISO Grid Planning Standards incorporate the WSCC and NERC Planning Standards. With regard to power flow and stability simulations, these Planning Standards are similar to WSCC and the NERC Planning Standards for Transmission System Contingency Performance. However, the Cal-ISO Standards also provide some additional requirements that are not found in the WSCC or NERC Planning Standards. The Cal-ISO Standards apply to all participating transmission owners 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 (Cal-ISO 2002a).

EXISTING FACILITIES AND RELATED SYSTEMS

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, and

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 kV lines that form the California Oregon Interties (COI). These lines carry California hydroelectric generation and imports from the Pacific Northwest. The Tracy substation is also connected to the Los Banos-Gates-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 would 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 overload reliability criteria violations in the area.

PROJECT DESCRIPTION

SWITCHYARD AND INTERCONNECTION FACILITIES

The EAEC site would 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 would 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 1,100 MW. Each generating unit would be connected to a 18/230 kV step-up transformer and the high voltage terminals of the transformers would be connected to a new EAEC 230 kV switchyard bay by overhead conductors. The new EAEC 230 kV switchyard would be configured with a 3,000-ampere main and a 3,000-ampere transfer bus. The switchyard would have four or five switch bays, each with a breaker and a half arrangement, for a total of up to fifteen air-insulated 230 kV circuit breakers. Each breaker would be designed for 63 kiloampere (kA) interrupting capacity. The EAEC switchyard would be connected to the existing Western grid by looping the existing Tracy-Westley double circuit lines (jointly owned by the MID and TID. It is currently operating as a single line, but would be split into two lines) through the EAEC switchyard by terminating the lines on two 2,000 ampere separate breakers at the 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 would be built on the south side of the EAEC switchyard. As a result, there would 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 would be done within the fenced yard of the EAEC plant. The preferred route for the new interconnection transmission lines would extend from the EAEC plant to Kelso Road.

ANALYSIS AND IMPACTS

SYSTEM RELIABILITY

Introduction

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 would 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, and voltage collapse) 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 include 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. The study may also be conducted for credible simultaneous loss of multiple (more than two) system elements. In addition to the above analysis, the studies may be performed to verify whether sufficient active or reactive power margins are available in the area system or area sub-system to which the new generator project would be interconnected. The SIS is followed by supplemental studies by the transmission owner with details provided in a Detailed Facility Interconnection Study (DFIS) or a Facility Cost Report (FCR).

Scope of the SIS and DFIS

The SIS was performed by Western, (the transmission owner), and PG&E (EAEC 2001e, Data Adequacy Response Set 1, Attachment TSE-1, SIS) with a 2005 summer peak case, which included approved PG&E and SMUD major transmission expansion plans, modeled major transmission system path flows, major generation in the system, and all proposed generation projects queued to be on-line before the on-line date of the EAEC project. The EAEC net maximum generation output was modeled as 1,070 MW. The Western report included a Power Flow study with and without the EAEC project under normal and contingency conditions, Post-transient Voltage study, and the Short Circuit study for PG&E, Western, SMUD, MID and TID systems. The PG&E report included a Dynamic Stability Analysis and a Short Circuit study with addition of the EAEC project for the PG&E system. Western performed the SIS with a 2005 spring peak case, but did not find any adverse impacts in the system due to the addition of the EAEC (EAEC 2001e, SIS, Attachment TSE-1).

The DFIS was performed by Western subsequent to the SIS with a 2005 summer peak case (EAEC 2002ddd, DFIS). The study report by Western included a Power Flow study under normal conditions and additional contingency conditions in the Western and SMUD systems, a Dynamic Stability analysis under additional contingencies in the Western and SMUD systems, a post-transient Load Flow study and a Short Circuit analysis.

Power Flow Study Results

Based on the SIS and DFIS results, there are some adverse impacts on the electrical grid due to interconnection of the EAEC as proposed. The results indicate that there would be overload criteria violations due to the project impact under normal (N-0) and emergency contingency (N-1 & N-2) conditions of the network in Western, SMUD, MID and PG&E systems.

Normal (N-0) Conditions and Mitigation

Under normal conditions of the network with all facilities in service in the 2005 summer peak case scenario, the study identifies that the project would cause one new thermal overload on the existing Tracy-Westley 230 kV Line #1 or the proposed EAEC-Westley 230 kV Line #1. The project would also aggravate several pre-project existing normal base case overloads on the transmission facilities as summarized in Table 1 below with respective selected mitigation measure(s) (EAEC 2001e, SIS; EAEC 2002ddd, DFIS, PG&E letters, SMUD letter, EAEC letter):

Table 1
2005 Summer Peak N-0 Overloads and Mitigation

Overloaded Facility	Percentage Loading of the Facility		Percentage Increment in Loading	SELECTED MITIGATION
	Pre-EAEC	Post-EAEC		
1. EAEC-Westly 230 kV Line #1	59.4	115.45	56.05	Western Project: Splitting the existing double circuit single 230 kV Line between Tracy and Westley into two separate 230 kV Lines, and Looping the two 230 kV Lines in and out of the proposed new EAEC Switchyard.
2. Brighton 230/115 kV Transformer Bank	188.0	190.40	2.4	PG&E Project T-758: Installing a second 230/115 kV transformer bank at Brighton in 2004 and/or congestion management, returning loading to pre-EAEC level, by curtailing EAEC generation.

Overloaded Facility	Percentage Loading of the Facility		Percentage Increment in Loading	SELECTED MITIGATION
	Pre-EAEC	Post-EAEC		
3. Los Banos 230/70 kV Transformer bank	123.53	126.23	2.7	PG&E Project T-710: Installing an additional 230/70 kV transformer bank at Los Banos substation by June 2005 and/or congestion management, returning the loading to pre-EAEC level, by curtailing EAEC generation.
4. Pittsburg-Tassajara 230 kV Line	100.3	102.78	2.48	PG&E Project T-665: Reconductor the Pittsburg-Tassajara 230 kV Line by June 2002 and/or congestion management returning loading to pre-EAEC level, by curtailing EAEC generation.
5. Cotra Costa-Las Positas 230 kV Line	100.4	102.4	2.0	PG&E Project T-772: Reconductor the Cotra Costa-Las Positas 230 kV Line by June 2002 and/or congestion management returning loading to pre-EAEC level, by curtailing EAEC generation.
6. New calt-Flint 115 kV Line	122.8	123.8	1.0	PG&E Project T-444: Installing SCADA system in the area and re-rating Gold Hill-Placer #1 and #2 115 kV lines (the target line is a tap section off the #2 line) to 3 feet per second wind speed rating by June, 2002 and/or congestion management, returning loading to pre-EAEC level, by curtailing EAEC generation.
7. Horshalt-Newcalt 115 kV Line	122.7	123.7	1.0	PG&E Project: T-444: Installing SCADA system in the area and Re-rating Gold Hill-Placer #1 and #2 115 kV lines (the target line is a tap section off the #2 line) to 3 feet per second wind speed rating by June 2002 and/or congestion management, returning loading to pre-EAEC level, by curtailing EAEC generation.
8. Panoche 230/115 kV Transformer Bank #1	137.09	138.08	0.99	PG&E status: Overloads no longer exist in the transformer bank due to several generation projects placed on-line in the Panoche 115 kV system.
9. Panoche-Panoche 2M 230 kV Line or Panoche 230/115 kV Transformer Bank #2	138.27	139.19	0.92	PG&E status: Overloads no longer exist in the transformer bank due to several generation projects placed on-line in the Panoche 115 kV system.

Overloaded Facility	Percentage Loading of the Facility		Percentage Increment in Loading	SELECTED MITIGATION
	Pre-EAEC	Post-EAEC		
10. Proctor-Hedge 230 kV Line	129.09	146.65	17.56	SMUD Project: Reconductor the Proctor-Hedge 230 kV Line if Rio Linda/Elverta Generation Project comes on-line before EAEC. Otherwise operating procedures by curtailing EAEC generation to eliminate any potential overload caused by EAEC (see Comments on Mitigation Measures).
11. Elverta S- Natoma S 230 kV LIne	106.28	115.8	9.52	SMUD Project: Reconductor the Elverta S- Natoma S 230 kV Line if Rio Linda/Elverta Generation Project comes on-line before EAEC. Otherwise no action needed by EAEC.

Contingency (N-1/Cal-ISO Category B) Conditions and Mitigation

Under single (N-1) or Cal-ISO Category B contingency conditions, the study identifies that the project would cause one new emergency overload on the existing Tracy-Westley 230 kV Line #1 or the proposed EAEC-Westley 230 kV Line#1. In addition the project would violate overload planning criteria by increasing pre-project existing N-1/Category B emergency overloads on the following transmission facilities as summarized in Table 2 below with respective mitigation measure(s) (EAEC 2001e, SIS; EAEC 2002ddd, DFIS, PG&E letters, SMUD letter, EAEC letter):

Table 2:
2005 Summer Peak N-1/Category B Emergency Overloads and Mitigation

Overloaded Facility	N-1 or Category B Contingency	Percentage Loading of the Facility		Percentage increment in Loading	SELECTED MITIGATION
		Pre-EAEC	Post-EAEC		
1. EAEC-Westley 230 kV Line#1	Overloaded for 8 contingencies, most severe contingency: Tracy- Hurley # 1 or 2 230 kV LIne	63.7	120.33	56.63	Western Project: Splitting the existing double circuit single 230 kV Line between Tracy and Westley into two separate 230 kV Lines, and Looping the two 230 kV Lines in and out of the proposed new EAEC Switchyard.
2. Pittsburg-Tassajara 230 kV Line	Pittsburg-East Shore 230 kV line	100.15	102.34	2.19	PG&E Project T-665: Reconductor the Pittsburg-Tassajara 230 kV Line by June 2002 and/or congestion management, returning loading to pre-EAEC level, by curtailing EAEC generation.
3. Pittsburg-East Shore 230 kV Line	Overloaded for 2 contingencies. Severe Contingency: Pittsburg-San Mateo 230 kV Line	107.66	109.68	2.02	PG&E Project T-768: Installing 10 ohm reactors on Pittsburg-San Mateo and Pittsburg-East Shore 230 kV Lines by April 2002 and/or congestion management, returning loading to pre-EAEC level, by curtailing EAEC generation.

Overloaded Facility	N-1 or Category B Contingency	Percentage Loading of the Facility		Percentage increment in Loading	SELECTED MITIGATION
		Pre-EAEC	Post-EAEC		
4. Pittsburg- San Mateo 230 kV line	Pittsburg-East Shore 230 kV line	103.08	104.98	1.9	PG&E Project T-768: Installing 10 ohm reactors on Pittsburg-San Mateo and Pittsburg-East Shore 230 kV Lines by April 2002 and/or congestion management, returning loading to pre-EAEC level, by curtailing EAEC generation.
5. Palermo 230/115/60 kV transformer Bank	Overloaded for 7 contingencies, most severe contingency: Vaca-Dixon 500/230 kV transformer Bank	102.35	109.24	6.89	PG&E Project T-686: Installing an additional Palermo 230/115 kV transformer Bank or Replace the existing Palermo transformer Bank or congestion management, returning loading to pre-EAEC level, by curtailing EAEC generation.
6. Panoche-Panoche 2M 230 kV Line or Panoche 230/115 kV Transformer Bank #2	New Melones-Wilson 230 kV line	131.76	134.65	2.89	PG&E status: Overloads no longer exist in the transformer bank due to several generation projects placed on-line in the Panoche 115 kV system.
7. Brighton 230/115 kV transformer Bank	Woodland-Davis 115 kV Line and Woodland Generation	184.91	186.21	1.3	PG&E Project T-758: Installing a second 230/115 kV transformer bank at Brighton in 2004 and/or congestion management, returning loading to pre-EAEC level, by curtailing EAEC generation.
8. Los Banos 230/70 kV transformer Bank	New Melones-Wilson 230 kV line	111.86	115.09	3.15	PG&E Project T-710: Installing an additional 230/70 kV transformer bank at Los Banos substation by June 2005 and/or congestion management, returning the loading to pre-EAEC level, by curtailing EAEC generation.
9. Proctor-Hedge 230 kV Line	Overloaded for 16 contingencies, most severe contingency: Cottonwood-Roseville 230 kV Line	101.24	117.54	16.3	SMUD Project: Reconductor the Proctor-Hedge 230 kV Line if Rio Linda/Elverta Generation Project comes on-line before EAEC. Otherwise operating procedures by curtailing EAEC generation to eliminate any potential overload caused by EAEC (see Comments on Mitigation Measures).
10. Elverta S-Natoma S 230 kV Line	Overloaded for 15 contingencies, most severe contingency: Elverta-Hurley #1 230 kV Line	112.13	123.16	11.03	SMUD Project: Reconductor the Elverta S- Natoma S 230 kV Line if Rio Linda/Elverta Generation Project comes on-line before EAEC. Otherwise no action needed by EAEC.
11. Parker MID 230/69 kV transformer Bank # 1 or #2	Parker MID-Parker 2M 230 kV Line or Parker MID-Parker 1 M 230 kV Line	109.7	113.16	3.46	MID project: Installing a third Parker MID 230/69 kV transformer Bank

Contingency (N-2/Cal-ISO Category C) Conditions and Mitigation

Under single (N-2) or Cal-ISO Category C contingency conditions, the study identifies that the project would cause one new emergency overload on the existing Tracy-Westley 230 kV Line or the proposed EAEC-Westley 230 kV Line #1. The project would also violate overload planning criteria by aggravating pre-project existing emergency overloads on the following transmission facilities as summarized in the Table 3 below with respective selected mitigation measure(s) (EAEC 2001e, SIS; EAEC 2002ddd, DFIS, PG&E letters, SMUD letter, EAEC letter):

Table 3
2005 Summer Peak N-2/Category C Emergency Overloads and Mitigation

Overloaded Facility	N-2/Category C Contingency	Percentage Loading of the Facility		Percentage Increment in Loading	SELECTED MITIGATION
		Pre-EAEC	Post-EAEC		
1. EAEC-Westley 230 kV Line#1	Overloaded for 10 contingencies, most severe contingency: Tracy-Hurley 230 kV Lines #1 &2	68.7	128.3	59.6	Western Project: Splitting the existing double circuit single 230 kV Line between Tracy and Westley into two separate 230 kV Lines, and Looping the two 230 kV Lines in and out of the proposed new EAEC Switchyard.
2. Capehorn-Rollins 60 kV Line (A tap section of Drum-Grass valley-Weimar 60 kV Line)	Overloaded for 2 contingencies, most severe contingency: Tracy 230 kV West Bus section	113.8	115.4	1.6	PG&E Operation Arrangement: Overload eliminated by opening Weimar Switch #79.
3. Panoche-Panoche 2M 230 kV Line or Panoche 230/115 kV transformer Bank #2	Overloaded for 4 contingencies, most severe contingency: Tracy 230 kV East Bus section	138.9	140.9	2.0	PG&E status: Overloads no longer exist in the transformer due to several generation projects placed on-line in the Panoche 115 kV system.
4. Panoche 230/115 kV transformer Bank #1	Overloaded for 5 contingencies, most severe contingency: Tracy 230 kV East Bus section	137.7	139.8	2.1	PG&E status: Overloads no longer exist in the transformer due to several generation projects placed on-line in the Panoche 115 kV system.
5. Bonnie N-Drum 60 kV Line	Overloaded for 2 contingencies, most severe contingency: Tracy-Tesla and Tracy- Los Banos 500 kV Lines	113.01	115.33	2.32	PG&E Operation Arrangement: Overload eliminated by opening Weimar Switch #79.
6. Bonnie N-Capehorn 60 kV Line	Overloaded for 2 contingencies, most severe contingency: Tracy-Tesla and Tracy- Los Banos 500 kV Lines	107.83	110.11	2.28	PG&E Operation Arrangement: Overload eliminated by opening Weimar Switch #79.

Overloaded Facility	N-2/Category C Contingency	Percentage Loading of the Facility		Percentage Increment in Loading	SELECTED MITIGATION
		Pre-EAEC	Post-EAEC		
7. Proctor-Hedge 230 kV Line	**Overloaded for 9 contingencies, most severe contingency: Tracy-Tesla and Tracy- Los Banos 500 kV Lines**	**118.06**	**126.56**	**8.51**	**SMUD Project: Reconductor the Proctor-Hedge 230 kV Line if Rio Linda/Elverta Generation Project comes on-line before EAEC. Otherwise operating procedures by curtailing EAEC generation to eliminate any potential overload caused by EAEC (see Comments on Mitigation Measures).**
8. Los Banos 230/70 kV transformer Bank	**Overloaded for 3 contingencies, most severe contingency: Tracy 230 kV East bus section**	**122.1**	**127.4**	**5.3**	**PG&E Project T-710: Installing an additional 230/70 kV transformer bank at Los Banos substation by June 2005 and/or congestion, management returning the loading to pre-EAEC level, by curtailing EAEC generation.**
9. Contra Costa-Las Positas 230 kV Line	**Overloaded for 2 contingencies, most severe contingency: Morago 230 kV bus section**	**104.11**	**106.64**	**2.53**	**PG&E Project T-772: Reconductor the Contra Costa-Las Positas 230 Line by June 2002 and/or congestion management, returning loading to pre-EAEC level, by curtailing EAEC generation.**
10. Pittsburg-Tassajara 230 kV Line	**Overloaded for 3 contingencies, most severe contingency: East Shore 230 kV bus section**	**100.66**	**102.86**	**2.2**	**PG&E Project T-665: Reconductor the Pittsburg-Tassajara 230 kV Line by June, 2002 and/or congestion management, returning loading to pre-EAEC level, by curtailing EAEC generation.**
11. Brighton 230/115 kV transformer Bank	**Tracy 230 kV East Bus section**	**192.4**	**195.6**	**3.2**	**PG&E Project T-758: Installing a second 230/115 kV transformer bank at Brighton in 2004 and/or congestion management, returning loading to pre-EAEC level, by curtailing EAEC generation.**

Comments on Mitigation Measures

The existing 230 kV line between the 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 studies find that with interconnection of the EAEC plant as proposed, under normal conditions of the network and under several credible single (N-1) and double (N-2) contingency conditions in the Western, SMUD and PG&E systems, the Tracy-Westley 230 kV line would be loaded up to about 128 percent of its emergency rating with the present single line configuration (EAEC 2001e, SIS). Staff, therefore, concurs with Western that to accommodate the EAEC project it would be essential to split the double circuit line into two separate lines by terminating the lines on separate breakers at both ends as proposed. As a result, since the two 230 kV lines would loop in and out of the EAEC switchyard, there would 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 splitting the Tracy-Westley 230 kV line would resolve the system impact concerns expressed by MID (MID 2001a).

The existing Tracy 230 kV substation is currently configured as a Main and a Transfer Bus with a single breaker system. The Western report in the DFIS proposes to convert the Tracy 230 kV substation to a Double Bus and a Double Breaker configuration which would increase the operational reliability of the substation on its own as well as in the context of the EAEC interconnection (EAEC 2002ddd, DFIS). Western requires a Double Bus and Double Breaker configuration to split the single system into a double system with required operational and maintenance flexibility to maintain the operational reliability of the substation. Staff concurs that such arrangement is according to good utility practice and would enhance system reliability.

The SMUD projects for reconductoring the Proctor-Hedge and Elverta S-Natoma S 230 kV lines as stated in Tables 1, 2 and 3, are warranted due to the interconnection impact of the proposed Rio Linda/Elverta power project of Florida Power & Light, which is ahead of EAEC in the generation interconnection queue. The EAEC project causes incremental overloads on these two lines on top of pre-project normal and emergency overloads. At this stage because the Rio Linda/Eleverta power project has been withdrawn from the licensing process it is highly unlikely that the Rio Linda/Elverta power project would materialize before the on-line date of EAEC. With the system modeled without the Rio Linda/Elverta power project, the EAEC causes a new slight overload in the Proctor-Hedge 230 kV line and does not cause any overload in the Elverta S-Natoma S 230 kV line. SMUD and the applicant have, therefore signed a letter agreement (EAEC 2002ddd, SMUD letter, EAEC letter) that, in the event the Rio Linda/Elverta power project does not materialize before the on-line date of EAEC, and the Proctor-Hedge and Elverta S-Natoma S 230 kV lines are not reconductored, then initially the EAEC owner and SMUD would work together in good faith to develop and implement appropriate operating procedures to mitigate any potential overloads on the Proctor-Hedge 230 kV line caused by the operation of the EAEC. However, if SMUD and EAEC could not come to an agreement satisfactory to SMUD on the development and implementation of operating procedures, the EAEC owner would be obligated along with any third party generation project developer to fund the transmission upgrades to SMUD's Proctor-Hedge 230 kV line up to a certain amount. Staff concurs with this mitigation arrangement.

The overloads on the PG&E transmission facilities as stated in Tables 1, 2 and 3 above, which comprise incremental overloads due to the EAEC project impact on top of substantial pre-project existing overloads, would be mitigated by the respective PG&E projects as mentioned in the Tables above (EAEC 2002ddd, PG&E letters). PG&E and the Cal-ISO have approved some of the PG&E projects and some are awaiting approval. The projects may be implemented in time for the EAEC on line date or deferred or cancelled. The PG&E letters of December 19, 2001 and April 15, 2002 (EAEC 2002ddd) state that since there is no guarantee that the mitigation project(s) would be approved and materialize, and would be operational in time for the 2005 on-line date of EAEC, the applicant may assume the cost of advancing the PG&E project(s) to coincide with the on-line date of EAEC. Alternately, if the applicant chooses to wait for PG&E to implement the project(s), EAEC would be solely responsible for transmission congestion management at their cost for returning the loading of the facility(s) to pre-EAEC level(s) by curtailing EAEC generation. While staff concurs with the alternate mitigation options as provided in the aforesaid PG&E letters, such arrangement of mitigation measures for the PG&E overloaded facilities is required to be accepted and confirmed by the applicant.

The MID mitigation project, which would consist of installing a third Parker MID 230/69 kV transformer bank would, mitigate overloading of the existing Parker MID transformer banks under contingency conditions. Staff finds this mitigation feasible.

Transient Stability Study Results

Dynamic stability studies were conducted by PG&E as part of the SIS using a 2005 summer peak 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 in the PG&E system (EAEC 2001e, Data Adequacy Response set 1, Attachment TSE-1, PG&E SIS pages 1-5, Appendices A & B). In the DFIS report (EAEC 2002ddd, DFIS), which is supplemental to the SIS, Western provided additional Dynamic Stability study results following credible N-1 and N-2 contingencies in the Western and SMUD systems

The SIS and DFIS results indicate that for integration of the EAEC project, there are no identified transient stability concerns on the transmission system following the selected disturbances.

Short Circuit Study Results and Mitigation

The short circuit study performed by PG&E with a 2005 case 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 2005 case included all future system additions including all new generation projects up to year 2005. 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 (PG&E T-558 project for Tesla transformer bank #6) 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. Staff considers this acceptable.

The short circuit study performed by Western (EAEC 2001e, Data Adequacy Response set1, Attachment TSE-1 page 9) with a 2005 case evaluated the impact of the EAEC project on the fault duties within the Western, SMUD, MID & TID facilities. The study results indicate that integration of the EAEC project would not overstress any equipment at the selected substations.

NEW TRANSMISSION LINE AND SYSTEM MODIFICATIONS

Besides the interconnection facilities and switchyard as proposed by the applicant (discussed above), accommodating the power output of the EAEC would not require any new transmission facility.

System modifications proposed by Western include splitting the existing 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. Also included is the MID project for installing a third Parker MID 230/69 kV transformer bank. The PG&E and SMUD projects are required for system reliability and it is preferred that these be implemented before the on-line date of the EAEC; however, EAEC has the option to participate in transmission congestion management by curtailing EAEC generation at their cost if the PG&E and SMUD projects are not built in time.

CUMULATIVE IMPACTS

The SIS and DFIS results show that multiple planned generation projects in the area including the EAEC project have incremental overload system impacts and also show direct impacts due to the EAEC. Considering that the location of the project is very close to the 500/230 kV Tracy substation or functionally at the Tracy substation, which is strongly interconnected through several 230 kV and 500 kV bulk power lines with the rest of northern California transmission system, staff believes that the project would have some cumulative impacts in the interconnected transmission system. The cumulative impacts due to the EAEC, as identified in the SIS and DFIS, would be mitigated.

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

The SIS and DFIS comply with NERC/WSCC, NERC and Cal-ISO planning standards and reliability criteria. All the overload criteria violations due to interconnection of the EAEC project would be mitigated effectively. The proposed EAEC switchyard would be located within the fenced yard of the EAEC plant and the overhead 230 kV interconnecting loop lines would extend from the plant to Kelso Road. Staff concludes that all facilities are acceptable and would comply with LORS assuming the Conditions of Certification are met.

Since Western would design, own and operate the EAEC power plant switchyard and outlet lines, and since either Western or the applicant under the supervision of Western would build the facilities, the recommended Conditions of Certification are not the same as those typically recommended by staff for facilities owned by a private developer. Western's role as a federal agency under the United States Department of Energy is to market and transmit electricity through high voltage transmission lines primarily from multi-user water projects. Western has the special expertise and experience to conform to industry standards and regulations.

By voluntarily agreeing to a joint analysis process with the Energy Commission and to any Conditions of Certification imposed by the Energy Commission for approval of the project, Western is not ceding any jurisdictional authority over federal facilities to the State of California.

FACILITY CLOSURE

PLANNED CLOSURE

This type of closure occurs in a planned and orderly manner such as at the end of the power plant's useful economic or mechanical life or due to gradual obsolescence. Under such circumstances, the owner is required to provide a closure plan 12 months prior to closure, which 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 (TO), in this case Western, to assure (as one example) that the TO's system would not be closed into the outlet thus energizing the project substation. Alternatively, the owner may coordinate with the TO to maintain some power service via the outlet line to supply critical station service equipment or other loads.[1]

UNEXPECTED TEMPORARY CLOSURE

An unplanned 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 establishing an on-site contingency plan (see **General Conditions Including Compliance Monitoring and Closure Plan**).

[1] These are mere examples, many more exist.

UNEXPECTED PERMANENT CLOSURE

This unplanned closure occurs when the project owner abandons the facility. This is considered to be a permanent closure. 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 Energy Commission's Compliance Project Manager (CPM) prior to the beginning of commercial operation of the facilities, would be developed to assure safety and reliability (see **General Conditions Including Compliance Monitoring and Closure Plan**).

RESPONSE TO AGENCY COMMENTS

DEPARTMENT OF WATER RESOURCES

On May 14, 2001, the California Department of Water Resources (DWR) submitted a letter regarding the potential effects of increased fault currents due to the addition of EAEC project on the electrical equipment at Banks Pumping and Gianelli Pumped-storage plants (DWR 2001a). In response, the applicant submitted a short circuit study to DWR (EAEC 2001m). The study results indicated that the marginal increases in fault currents would not overstress any electrical equipment at the DWR plants. Staff concurs with the study results.

MODESTO IRRIGATION DISTRICT

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 had 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 would be essential for the EAEC project interconnection, and such transmission arrangement would 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 would have to coordinate the matter with the concerned parties.

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

Staff concludes as follows:

The EAEC SIS and DFIS was conducted for a 2005 summer peak case and included approved PG&E and SMUD major transmission expansion plans, modeled major transmission system path flows, included major generation in the system and proposed generation projects in the queue to be on line before the EAEC project. The Rio Linda/Elverta power plant, which was initially ahead of EAEC in the generation queue, was recently withdrawn from the siting process. However, this does not change staff's substantive conclusions because as discussed previously, mitigation for this eventuality has been identified and preliminarily agreed to by SMUD and the EAEC applicant.

Upon review of the SIS/DFIS, staff finds that the EAEC would have some adverse impacts on the transmission system. There would be overload criteria violations in several transmission facilities for interconnection of the EAEC plant under normal and emergency conditions of the electrical grid. The Western, PG&E, SMUD and MID projects identified in Tables 1, 2, and 3 and/or mitigation alternatives like transmission congestion management as selected by the transmission owners to eliminate the overload violations, are considered effective, are according to modern good utility practices, and are acceptable to staff. The applicant, however, needs to confirm their acceptance of the mitigation alternative for each criteria violation as selected by the respective transmission owner (see Conditions of Certification, TSE-1h). iv)).

The EAEC switchyard and interconnection facilities to the Western grid, by looping the Tracy-Westley 230 kV line through the EAEC switchyard, would be adequate and reliable. To accommodate interconnection of the EAEC project and to offset downstream adverse impacts on the transmission system, it would 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 two separate breakers at the Tracy and Westley substations. As a result, since the two 230 kV lines would loop in and out of the EAEC 230 kV switchyard, there would be two Tracy-EAEC and two EAEC-Westley 230 kV lines. This arrangement would also resolve the system impact concerns of MID.

The power plant switchyard, outlet lines, and termination are in accordance with good utility practices and are acceptable. These facilities would be designed, owned and operated by Western. Either Western or the applicant would build these facilities. If the applicant builds the facilities, the construction would be according to Western design and specifications, and as such would be done under the supervision of Western. With implementation of the conditions of certification recommended by staff, these facilities would comply with LORS.

RECOMMENDATIONS

If the Commission approves the project, staff recommends the following Conditions of Certification to ensure system reliability and conformance with LORS.

CONDITIONS OF CERTIFICATION FOR TSE

TSE-1 The project owner shall ensure that the design, construction and operation of the proposed transmission facilities shall conform to all applicable LORS including the requirements 1a) through 1h) listed below. The substitution of Compliance project manager (CPM) approved "equivalent" equipment and an equivalent substation configuration is acceptable.

a) The project 230 kV switchyard shall have switch bays with a double bus, and a breaker and a half configuration.

b) The power plant switchyard and outlet lines shall meet or exceed the electrical, mechanical, civil and structural requirements of Western interconnection standards, Western' DFIS, CPUC General Orders 95 (GO-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.

c) Breakers and buses in the power plant switchyard and other switchyards, where applicable, shall be sized to comply with a short-circuit analysis.

d) Outlet line crossings and line parallels with transmission and distribution facilities shall be coordinated with the transmission line owner and comply with the owner's standards.

e) Termination facilities shall comply with applicable Western interconnection standards.

f) The project conductors shall be sized to accommodate the full output from the project.

g) 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 switchyard to the two lines. The existing Tracy 230 kV bays 1 to 12 shall be converted from main and transfer to a double bus-double breaker configuation.

h) The project owner shall provide:

   i) Any modified Detailed Facility Interconnection Study (DFIS) including a description of facility upgrades, operational mitigation measures, and/or Remedial Action Scheme (RAS) or Special Protection System (SPS) sequencing and timing if applicable,

   ii) Executed Facility Interconnection Agreement with Western,

   iii) A copy of the Notice to Cal-ISO prior to synchronization of the facility with the California transmission grid.

iv) A letter stating that the mitigation measures or projects for each criteria violation selected by Western, PG&E, SMUD and MID are acceptable.

Verification: At least 60 days prior to the start of grading of the power plant switchyard or transmission facilities, the project owner shall submit to the CPM for approval:

Electrical one line diagrams signed and sealed by a registered professional electrical engineer in responsible charge (or other approval acceptable to the CPM), a route map, and an engineering description of equipment and the configurations covered by the requirements 1a) through 1h) above.

The Detailed Facilities Study (if modified) including a description of facility upgrades, operational mitigation measures and/or RAS or SPS, and the Interconnection Agreement (if either one are not otherwise provided to the Commission previously) and a signed letter from the project owner stating that the mitigation measures selected by Western, PG&E, SMUD and MID are acceptable. Substitution of equipment and substation configurations shall be identified and justified by the project owner for CPM approval.

TSE-2 The project owner shall inform the CPM of any impending changes that may not conform to the requirements 1a) through 1h) of **TSE-1**, and have not received CPM 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 CPM.

Verification: At least 60 days prior to the construction of the power plant switchyard and transmission facilities, the project owner shall inform the CPM of any impending changes that may not conform to requirements 1a) through 1h) of **TSE-1** and request approval to implement such changes.

TSE-3 The project owner shall be responsible for the inspection of the transmission facilities during project construction, and any subsequent CPM approved changes thereto, to ensure conformance with CPUC GO-95 or NESC, Title 8 of the California Code of Regulations, Articles 35, 36 and 37 of the “High Voltage Electric Safety Orders”, Western’s interconnection standards, NEC, related industry standards and these conditions. In case of non-conformance, the project owner shall inform the CPM 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 to the grid, the project owner shall transmit to the CPM an engineering description(s) and one-line diagrams of the “as built” facilities signed and sealed by the registered electrical engineer in responsible charge (or other verification acceptable to the CPM, such as a letter stating that the attached diagrams have been verified by the engineer). A statement attesting to conformance with CPUC GO-95 or NESC, Title 8 of the California Code of Regulations, Articles 35, 36 and 37 of the “High Voltage Electric Safety Orders”, Western’s interconnection standards, NEC, related industry standards and these conditions.

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.

Cal-ISO (California Independent System Operator) 2002a. Cal-ISO Grid Planning Standards, February 2002.

CEC (California Energy Commission) 2001a. First Set of Data Requests. Dated and docketed May 10, 2001.

DWR (Department of Water Resources) 2001a. Letter from DWR to CEC with copy to EAEC about potential increase in fault currents at the DWR plants, dated May 14, 2001 and docketed on May 18, 2001.

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 Adequacy 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.

EAEC (East Altamont Energy Center, LLC) 2001m. Letter from EAEC to DWR with copy to CEC about potential effects of increased fault currents at the DWR plants, dated July 20, 2001 and docketed on July 25, 2001.

EAEC (East Altamont Energy Center, LLC) 2002ddd. Response to Data Requests set 6, East Altamont Energy Center (01-AFC-4), The Detailed Facility Study Report from Western, PG&E letter of December 19, 2001 and SMUD letter of April 11, 2002, EAEC letter of May 24 2002. Submitted to the California Energy Commission on April 23, 2002

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.

NERC (North American Electric Reliability Council) 1998. NERC Planning Standards, September 1997.

WSCC (Western Systems Coordinating Council) 2001. NERC/WSCC Planning Standards, June 2001.

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) would 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, would 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 lant 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.

ALTERNATIVES

Testimony of 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.

The California Energy Commission (Energy Commission) does not have the authority to approve an alternative or require Calpine to move the proposed project to another location, even if it identifies an alternative site that meets the project objectives and avoids or substantially lessens on one or more of the significant effects of the project. One of the applicant's primary objectives for the project is to be online by 2005, and the applicant has a contract with the California Department of Water Resources (DWR) to provide electricity. In order to meet that contract, the applicant must receive Energy Commission certification by November 30, 2002 or 90 days thereafter. Implementation of an alternative site would require that the applicant submit a new AFC, including revised engineering and environmental analysis; this more rigorous AFC-level analysis of any of the alternative sites could reveal environmental impacts, non-conformity with laws, ordinances, regulations, and standards; or potential mitigation requirements that were not identified during the more general alternatives analysis presented herein. None of the alternatives would allow the applicant to meet the DWR contract requirements or the objective of being online by 2005. The additional time required to complete site engineering and application preparation would be about one year for permitting and two years for construction. Staff believes this is an important objective that supports development of California's electricity supply.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

Calpine proposes to interconnect the proposed EAEC to the Tracy substation, which is under the jurisdiction of the 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 is the Lead Agency under CEQA. Western and the Energy Commission are undertaking a combined NEPA/CEQA analysis.

CALIFORNIA ENVIRONMENTAL QUALITY ACT CRITERIA

The “Guidelines for Implementation of the California Environmental Quality Act,” Title 14, California Code of Regulation, Section15126.6(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)).

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 Environmental Assessment (EA) is intended to provide sufficient evidence and analysis for determining whether to prepare an environmental impact statement.

Alternatives identified must be consistent with Western’s purpose and need for the action under consideration, which include the applicant’s objectives. The applicant’s objectives are described below 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 has determined that alternative power plant sites are not consistent with the purpose and need or the applicant’s objectives. Because alternative sites are not consistent with Western’s purpose and need to provide open access at the place requested, there is no need for Western to analyze alternative sites.

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 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.

The proposed power plant would require a 230-kilovolt (kV) switchyard and two new approximately 0.5 mile 230-kV transmission lines. 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. The two new double-circuit

230-kV transmission lines would connect the new switchyard to an existing 230-kV double-circuit transmission line that will be sectionalized to provide interconnections with Western's Tracy Substation and the Westley Substation. New electrical equipment would also be installed within the existing boundaries of the Tracy and Westley Substations. Natural gas for the facility would be delivered via a new approximately 1.8-mile 20-inch pipeline that would connect to Pacific Gas and Electric (PG&E)'s existing natural gas pipeline line located at the intersection of Bruns Road and Kelso Road. A ½-acre gas metering station would be required at the interconnection point. Byron Bethany Irrigation District (BBID) would supply approximately 4,600 acre-feet of raw water for cooling and process make-up water via a 2.1-mile pipeline (EAEC 2001a, Section 2). A recycled water pipeline would run along the south side of Byron Bethany Road and would enter the 174-acre parcel at the northeast corner.

APPLICANT'S SITE SELECTION CRITERIA

The following site selection criteria were used by the applicant for choosing the proposed site; however, staff does not necessarily concur that all the criteria must be met when analyzing alternative sites. Therefore, the critical project objectives, as determined by staff, are listed in the following section. According to the AFC, the applicant chose the proposed site for the following reasons (EAEC 2001a).

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 laydown 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:

1. Identify the basic objectives of the project, provide an overview of the project, and describe its potentially significant adverse impacts.
2. Identify and evaluate technology alternatives to the project such as increased energy efficiency (or demand side management) and the construction of alternative technologies (e.g. wind, solar, or geothermal).
3. Identify and evaluate alternative locations or sites.
4. 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 its EA, Western reviewed the results of the Energy Commission alternatives analysis and determined which alternatives were consistent with Western’s purpose and need section. All alternative sites or technologies were found not to be consistent with Western’s purposes and need were dismissed from the full analysis of the EA. These alternatives nonetheless remain as part of the Energy Commission’s CEQA analysis. (Note that the entire Final Staff Assessment will serve as Western’s EA.)

PROJECT OBJECTIVES

Based on analysis of the EAEC 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 2005.

NEPA PURPOSE AND NEED STATEMENT

NEED FOR WESTERN ACTION

Calpine has applied to interconnect with Western’s transmission system at the Tracy Substation. Western must respond to Calpine’s request for an interconnection with its 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 Department of Energy (DOE) has issued a Power Marketing Administration Open Access Transmission Policy that does apply to Western that supports the intent of the FERC's Notice of Proposed Rulemaking for Open Access Transmission. To comply with FERC Orders 888 and 888-A, Western published in the Federal Register on January 6, 1998 its Notice of Final Open Access Transmission Service Tariff (Tariff). Under this 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. Protecting 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.

For purposes of the NEPA process, Western will determine the significance of impacts in a separate determination issued after this EA. If Western determines there are no significant impacts, it will issue a Finding of No Significant Impacts (FONSI). A preliminary version of the FONSI will be made available for public review for at least 30 days. Publishing a final FONSI would complete the assessment portion of the federal environmental process. If Western determines that there are potential significant impacts, it will publish a Notice of Intent to prepare an Environmental Impact Statement in the Federal Register and distribute copies to the project's mailing list.

Western's conclusions about significance may vary from the conclusions reached by Energy Commission Staff and the Energy Commission. Western will consider the FSA findings and Energy Commission determinations, but may apply different weightings to the Commission Staff's significance criteria or may consider different criteria.

POTENTIAL SIGNIFICANT ENVIRONMENTAL IMPACTS

In this FSA, staff has identified the potential for significant environmental effects of the proposed project in the following technical areas (summarized below): air quality, biology, land use, visual resources, hazardous materials, and soil and water resources. With mitigation, impacts in all of these issue areas except visual resources have been found to be less than significant. However, staff has determined that there would be unmitigable significant impacts to visual resources from the proposed project.

Issue area with significant impacts:

Visual Resources

Although the proposed power plant facility would be located near transmission lines and a substation, staff concludes that the facility would be inconsistent with the existing rural character of the general area. Furthermore, the proposed facility 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 had the potential to mitigate the visual impacts of the proposed project. However, biology staff of the Energy Commission, CDFG, and USFWS were concerned about potential biological impacts of the proposed landscaping. Although a landscaping plan has been developed that was deemed to be adequate by the CDFG and the USFWS, the plan does not adequately reduce the visual impacts of the proposed project. Staff therefore concludes that the project would result in unmitigable significant impacts to visual resources.

Staff concluded that the proposed project structures would be inconsistent or partially inconsistent with seven of Alameda County's LORS, two of which would constitute an adverse but not significant impact, another two of which could be mitigated to a level of less than significant, and two more that would constitute a significant, unmitigable impact. The Alameda County Planning Department, however, has found that the project would be consistent with all of the county's applicable LORS. Consistent with California Code of Regulations, title 20, section 1714.5(b), staff gives due deference to Alameda County's determination that the project complies with the visual resources LORS under its jurisdiction. Therefore, staff's determination is that the project is consistent with all applicable LORS.

Issue areas found to have less than significant impacts if recommended mitigation is adopted:

Air Quality

The EAEC as proposed has the potential to create significant impacts to local and regional air quality. Staff found that the project's emissions of oxides of nitrogen (NOx) and volatile organic compounds (VOC) have the potential to cause significant impacts relative to the state and federal 1-hour ozone air quality standards. Further, the project's emissions have the potential to cause significant impacts relative to the state 24-hour PM10 (particulate matter less than 10 microns in diameter) air quality standard. The project would also contribute to existing violations of the recently promulgated federal 8-hour ozone and 24-hour PM2.5 standards. However, the significance of these contributions is uncertain because the monitoring and attainment designation has not been completed.

The proposed location for the EAEC is in Alameda County and within the jurisdictional boundaries of the Bay Area Air Quality Management District (BAAQMD), but very near the border with San Joaquin County and the San Joaquin Valley Air Pollution Control District (SJVAPCD). Because the proposed site is east of the Altamont pass, the project's emissions would directly affect air quality in the SJVAPCD.

Under BAAQMD rules, the project applicant must offset air quality emissions, and can accomplish this by purchasing emission reduction credits (ERCs) anywhere within the BAAQMD territory. The applicant has satisfied BAAQMD offset requirements by purchasing Bay Area Emission Reduction Credits (ERCs) far to the west of the project site and of the Altamont Pass, where the offsets would result in only a small reduction of pollution transport into the area impacted by the project. Staff has determined that these ERCs are inadequate to fully mitigate the location and magnitude of local air quality impacts that would be caused by the project.

The applicant put forth a proposal designed to provide air quality benefits to offset the residual air quality impacts identified by staff. Staff evaluated this proposal and found that the proposal would be insufficient, both in terms of the tons of air pollution reduced, and in the specificity and enforceability of the measures proposed. Staff has identified two ways in which the applicant can fully mitigate the project's local air quality impacts. Staff's preferred method would be for the applicant to implement specific local air quality improvement programs detailed in staff's **Air Quality** analysis. Staff incorporated some of the elements of the applicant's proposal into an air quality improvement program that would fully mitigate the project's local air quality impacts. Alternatively, the applicant could purchase ERCs from the SJVAPCD sufficient to offset staff's identified residual impacts. Staff would prefer that all feasible actual emission reduction scenarios be explored first, and that when those scenarios are exhausted or are not deemed feasible, then any remaining emissions shortfall be met through the acquisition of ERCs from the SJVAPCD offset bank.

The proposed project currently does not comply with the District's Best Available Control Technology (BACT) requirements for NOx and CO emissions, and does not meet U.S. Environmental Protection Agency and California Air Resources Board guidelines for NH3 emissions. However, the District's conditions, which are contained in staff's proposed conditions of certification, will compel the project meet the District's BACT requirements. With full implementation of staff's proposed conditions of certification, the project will meet this and all other applicable LORS.

Biological Resources

The project area is part of a critical habitat pinch-point for the northern satellite population of the San Joaquin kit fox, a Federal and State listed species. Habitat mitigation that compensates for habitat loss and protects local habitats has been under review by staff in consultation with CDFG and USFWS. The applicant has proposed to mitigate for significant adverse impacts to listed species by purchasing mitigation habitat. Specifically, the applicant proposes to place a conservation easement on the Gomes Farms property, a 151-acre parcel that lies approximately one mile west of the EAEC project site. The applicant would further prepare a management plan, and establish an endowment to manage the land in perpetuity based upon a Property Analysis Report (PAR). The PAR will be conducted through the Center for Natural Lands Management (CNLM). The mitigation land would be managed by a qualified third party natural land management organization approved by Energy Commission staff, USFWS, CDFG, and Western.

While earlier versions of landscaping plans were found to create unacceptable biological impacts, the most recent landscaping plan proposed by the applicant was deemed adequate by the CDFG and USFWS. In contrast to the original landscaping plan, the applicant's final plan would minimize the use of large trees, limit the extent of landscaping within the project footprint, provide a substantial number of native plant species, and maintain a ground clearance of 3 feet for all vegetation. Staff concurs with the position of CDFG and USFWS that the area within which the EAEC is located in a critical habitat pinch-point for the San Joaquin kit fox. Further degradation in habitat quality and quantity (including connectivity) from additional landscaping, would cause significant adverse impacts to the kit fox population. Though staff would prefer no landscaping around the project from the perspective of protecting the kit fox from predation and habitat degradation, the April 3, 2002 landscaping plan, combined with the applicant's proposed management of the landscaping, would minimize impacts. Staff has proposed conditions of certification that would mitigate all biological impacts to less than significant, and has further proposed conditions that, when fully implemented, would allow the project to conform to all biological resource-related LORS.

Land Use

The project site is located on land that is zoned as large parcel agricultural. If not for the Energy Commission's "in-lieu of" status, the project would be required to obtain a conditional use permit from Alameda County, which in turn would require that the County make certain findings. Staff has received the conditional use permit findings from Alameda County. 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 East County Area Plan (ECAP), as amended by Measure D, is unclear. Although staff does not completely agree with the conclusions of the County, such conclusions are plausible and staff therefore defers to the County's interpretation of their own guidelines, standards, policies and conclusions that the EAEC is a consistent and allowed use.

The project's construction would result in the conversion of 40 acres from an agricultural use to a non-agricultural use and would 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 Association of Bay Area Governments (ABAG)'s Preservation of Agricultural Resources 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 including the contribution of funds to Alameda County for a 1:1 purchase of prime agricultural land for permanent farming use and/or easement purchases. Staff supports the County's successful effort to reach a mitigation agreement with the applicant regarding the conversion and loss of productive agricultural land, which is a potentially significant impact. After reviewing the final agreement, staff concludes that the payment of the $1 million fee agreed upon in the Farmlands Mitigation Agreement, in conjunction with **Condition of Certification LAND-7**, will mitigate the impacts of this project to a less than significant level.

Hazardous Materials

Anhydrous ammonia and natural gas are the only hazardous materials proposed for use at the power plant that may pose a risk of off-site impacts. Large amounts of anhydrous ammonia would be used in controlling the emission of oxides of nitrogen (NO_x) from the combustion of natural gas in the facility. The applicant has proposed state-of-the-art engineering controls for the containment of anhydrous ammonia, and staff has found that these controls, combined with the applicant's proposed administrative controls, will prevent off-site consequences should there be an accidental spill.

Staff also evaluated the risks associated with the transportation of anhydrous ammonia to the site. The anhydrous ammonia would be transported to the facility via U.S. Department of Transportation-certified tanker truck. While the risk associated with transportation of anhydrous ammonia is very low and well within accepted norms, as discussed in the **Hazardous Materials Management** section of this FSA, it is readily feasible to use aqueous ammonia. However, staff found that aqueous ammonia provided little if any risk reduction to in-route populations. Therefore in the absence of significant risk from use of anhydrous ammonia at this proposed facility, staff found no basis for requiring use of aqueous ammonia based on transport risks.

Staff's evaluation of the proposed project (with staff's proposed mitigation measures) indicates that hazardous materials use will not pose a significant risk of impacts on the public. Furthermore, with adoption of staff's proposed conditions of certification, the proposed project will comply with all applicable LORS.

Water and Soil Resources

The applicant has proposed to supply the project's non-potable water needs with fresh inland (raw) water. 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, offsetting raw water use. However, the applicant as yet has not made any firm commitments for this recycled water. While staff has established the willingness of Mountain House to commit all recycled water it produces for use at EAEC, the applicant has conditioned its willingness to implement use of recycled water on whether it becomes available under terms and conditions solely acceptable to itself. For the purposes of the Energy Commission's analysis of the AFC, staff's analysis considered the effects of both cases: assuming the plant would rely solely on raw water, and assuming the plant would fully utilize recycled water as it becomes available from Mountain House.

Staff has determined that EAEC's proposed use of high quality fresh inland water for cooling, process water, and other non-potable uses, when recycled water is available, would constitute a significant impact. Absent the maximum implementation of recycled water use by EAEC, staff believes the sole use of fresh water by the project for non-potable needs could diminish local water supply, potentially depriving BBID's other customers of fresh water or resulting in inadequate supplies to the EAEC project itself. Staff believes that potentially significant adverse cumulative impacts to other fresh water users (i.e., residential and agriculture) could result if EAEC does not maximize its use of recycled water for cooling and other non-potable requirements. The Mountain House Community Service District has committed to supply all of its recycled water for use by EAEC.

The use of reclaimed water for cooling is well proven and could serve 100 percent of the project's non-potable water demands prior to 2020. Several sources of recycled water suitable for meeting EAEC's non-potable requirements are being developed in the area and will be available by as early as 2003. Staff also has concluded that recycling of the storm water to the cooling tower basin is a reasonable and economic means to conserve water. Staff's proposed conditions of certification require that the project utilize recycled water for all of its non-potable operational requirements as soon as possible, but no later than January 1, 2020.

With full implementation of staff's proposed conditions of certification, the proposed EAEC project will comply with applicable LORS, be consistent with established state policy regarding the conservation of fresh water supplies, and avoid significant impacts to other fresh water users.

Noise

The proposed project could result in a substantial permanent increase in ambient noise levels at sensitive receptors, which may be considered a significant impact. The local noise environments in rural areas may be very quiet, with few discernable ambient noise sources. A power plant will introduce a new noise source with a distinctive acoustical character, quite different from typical ambient noise. In rural areas, the increases in ambient noise levels at sensitive receptors due to power plant operations may be relatively large, depending upon plant design, distance to the sensitive receptors, and whether other structures, topography, or noise sources affect power plant sound transmission. In the case of the proposed project, achieving power plant noise levels that ensure there will be no substantial increase in ambient noise levels would be problematic because homes on nearby agricultural parcels, the Livermore Yacht Club, and one school are located within about 1.5 miles from the plant site, and ambient noise levels are relatively low (well below LORS standards). If constructed as the applicant has proposed, the project's noise level at the nearest sensitive receptors would represent an increase of up to 13 dBA over the nighttime ambient background noise levels. Such increases in background noise levels would profoundly alter the noise regime in the project vicinity, and would cause a significant impact. To mitigate this impact, staff is proposing a condition of certification that would require the applicant to reduce the plant's noise output measured at the nearest residence, to a level that would only slightly increase ambient nighttime noise levels. If this and all other recommended Conditions of Certification are implemented, impacts will be less than significant and the project, if built, would comply with all applicable LORS.

SITE ALTERNATIVES

Eight alternative sites were identified during the initial screening of site alternatives. The applicant presented six of these as part of its alternatives analysis (Alternative Sites 1 through 6; EAEC 2001a, Section 9). Three of the applicant’s sites (Alternative Sites 1, 3, and 4) were eliminated from further analysis during the initial screening phase (see explanation in the “Alternatives Eliminated” section, below). The applicant’s Site 6 (the Tesla Site) was evaluated in the PSA, but has since been eliminated because a similar project (the Tesla Power Plant Project) is proposed at that site and Energy Commission review is currently underway. Siting an alternative at that location would not maintain a reasonable range of alternatives. Staff also identified two additional potential alternative sites, the I-580 Alternative Site 7 and the Lodi Site, during the initial screening. Alternative Site 7 was eliminated, but the Lodi Alternative Site was retained for detailed analysis. With the elimination of the Tesla Site, and in an effort to maintain a reasonable range of alternatives, staff identified an additional alternative site, the Panoche Site, which is evaluated in this section.

SCREENING CRITERIA USED TO SELECT ALTERNATIVE SITES

The following criteria were used to identify potential alternative sites. Each site was evaluated for its ability to:

1. Avoid or substantially lessen one or more of the potential significant effects of the project as described above;
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, 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.
3. Not create significant impacts of its own
4. Be available for purchase
5. Be sufficiently far from moderate or high density residential areas or to sensitive receptors (such as schools and hospitals) or to recreation areas.
6. Allow the project to be on-line on or before 2005.

Based on these screening criteria, four alternative sites were selected for further evaluation in this FSA: Mountain House Road Site (applicant's Site 2), Bruns Road Site (applicant's Site 5), Lodi Site (identified by staff), and Panoche Site (identified by staff). Please see **ALTERNATIVES Figures 1 through 3** for maps of these four sites.

The alternative sites were evaluated and the following issue areas were initially chosen to be evaluated because these are issue areas where impacts can be most serious for power plants: visual resources, biology, hazardous materials, land use, water and soil resources, cultural, transmission system engineering, air quality, and noise.

MOUNTAIN HOUSE ROAD SITE

The Mountain House Road Site (applicant's alternative Site 2) is located south of the proposed project site and is situated between the California Aqueduct and the Delta-Mendota Canal, immediately west of Mountain House Road. The parcel is in Alameda County and is zoned Agricultural, but is not designated as "Prime Farmland." The site consists of approximately 46 acres of flat land, located within a small valley at the base of the Coast Range foothills. The site is currently used for grazing.

A PG&E 230-kV transmission line is located approximately one quarter-mile east of the site. In addition, PG&E's 500-kV transmission lines cross the eastern side of the site. Both the 230-kV and 500-kV transmission lines feed the Tesla Substation to the south. The 230-kV line also feeds the Tracy Substation to the north. This site is not located in the BBID service area, so the water supply would be different than that of the proposed project, requiring contracts for water from the State Water Project (SWP). The natural gas pipeline would be less than 0.5 miles long and would pass under the Delta-Mendota Canal to connect to an existing PG&E natural gas transmission pipeline.

The Mountain House Site is within approximately two miles of a small community, with the nearest residence being approximately 2,000 feet to the east (EAEC 2001a, Section 9). The site is surrounded by low rolling hills that would block most views of the project site. Travelers on Mountain House Road would see the site only momentarily and then at viewing angles approximately 90 degrees off of the primary direction of travel (well beyond the primary cone of vision). A 500-kV transmission line crosses the project site and could present a constraint to site development. A wind farm is located immediately across from the site on the east side of Mountain House Road. A railroad right-of-way runs west to east on the southern portion of the parcel. A stream runs through the parcel; therefore, the potential for flooding would need to be evaluated.

Mountain House Site Impact Discussion

Air Quality: This site is located in the BAAQMD and in close proximity to the proposed project, so potential impacts would be similar to those of the proposed project.

Biological Resources: This site is within the Red-Legged Frog Recovery "Core" Area (EAEC 2001a). Furthermore, a stream runs through the site and wetland vegetation has been observed onsite, both of which could provide potential habitat for other sensitive biological resources. These wetland vegetation areas were observed to have heavy bird use. Impacts to sensitive habitats and special status species would likely be more significant than at the proposed location. However, visual screening (large trees) would not likely be required at this site, so the project at this location would not create the predator perching opportunities that are considered problematic at the proposed site. This site is also habitat for the San Joaquin kit fox.

Cultural Resources: To determine potential impacts of a project, a background search at the regional California Historic Information System (CHRIS) and a survey of both archaeological and historic resources would be necessary. The nearby windfarm and railroad are potential historic resources (if older than 45 years) that could be impacted by a power plant at this site. Additional analysis is necessary to determine whether the impacts would be significant. At this time, this site does not appear to have any potential advantages over the proposed site.

Hazardous Materials: The risk associated with use and transport of anhydrous ammonia and other hazardous materials at the Mountain House Site would be similar to that of the proposed project (less than significant).

Land Use and Soils: This land is also zoned Agricultural, but the parcel is not designated as "Prime Farmland." As with the proposed site, the project at this location may not be consistent with the County's land use designation and zoning for the Mountain House Road site. Also, the current development pattern for the area established by the ECAP, as amended by Measure D, is unclear and would need to be reviewed. The ECAP specifically calls for preservation of the Mountain House area for intensive agricultural use and the retention of rangeland in large, contiguous blocks for commercially viable grazing. Mitigation, in the form of an agricultural management plan for the preservation of agricultural land off- and potentially on-site, would likely be required.

Transmission System Engineering: There is a double circuit 230-kV transmission line on the east side of Mountain House Road. This double circuit line appears to contain the two Tracy-Tesla 230-kV circuits, each rated at 334 MVA (normal and emergency). These existing circuits do not have enough capacity to handle 1,100 MW; the line would have to be rebuilt from Tracy to Tesla to accommodate a 1,100 MW generating plant. There are also two 500-kV transmission lines adjacent to the site, on the west side of Mountain House Road. These lines are likely the two Table Mountain–Tesla 500-kV lines, each with a normal rating of 2,310 MVA and an emergency rating of 3,463 MVA. Either of these 500-kV transmission lines may be able to handle a 1,100 MW generating plant depending on previously scheduled loading. In summary there may be enough transmission capacity to connect 1,100 MW at the Mountain House site to the nearest existing 500-kV transmission line. It would be costly to install a 500-kV switchyard. However, this would likely be less expensive than the required upgrade of the 230-kV Tracy-Tesla line and substation terminations. An additional significant concern is that connections to California's backbone 500 kV system by generating units can be very difficult due to concerns about system reliability. A system impact study would need to be performed to confirm both bulk transmission system reliability adequacy and economic viability.

Visual Resources: The overall visual quality of the Mountain House site is low-to-moderate, reflecting the influences of the power transmission and generation facilities on the agricultural landscape. Viewer concern is rated moderate, as travelers on Mountain House Road anticipate a predominantly agricultural setting and the prominent forms of the wind farm facilities with their industrial character. However, the addition of prominent geometric forms with significant mass that block views of the foothills would be perceived as an adverse visual change. As a result of the screening provided by the surrounding terrain, project visibility would be low. Although the site would be visible in the foreground from Mountain House Road and the number of potential viewers would be moderate (estimated average daily traffic is 1,800 [EAEC 2001a, Table 8.10-2]), the duration of view would be brief. Overall viewer exposure would be moderate. The overall visual sensitivity of the Mountain House Site would be moderate.

The use of the Mountain House Site for a power plant would result in the introduction of linear and geometric forms of industrial character. Although the linear forms and lines of the project would be similar to that of the existing on-site 500-kV transmission line and nearby wind farms, the solid geometric mass of the structures would be substantially different. To the extent that project structures are briefly visible from Mountain House Road, the resulting visual contrast would be moderate. As previously described, the surrounding terrain would substantially screen the site from surr viewing locations. Therefore, the project dominance and view blockage that would be experienced by travelers on Mountain House Road and Grant Line Road would be subordinate and low (respectively) due to the very limited visibility of the project structures. The overall visual change resulting from the use of this site would be low-to-moderate. 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 occur at this site would cause an adverse but not significant visual impact.

Visible Plumes. The production of frequent and sizable water vapor plumes at this location would introduce prominent industrial features that would be visible from local and regional vantage points and would temporarily block views of portions of the Coast Range foothills and regional landmarks including Brushy Peak and Mount Diablo for some viewers. The number of viewers and duration of view would be low-to-moderate. Considering the relatively short duration of plumes during the day for only the coolest months of the year, and the overall viewer sensitivity, the resulting visual impact would be less than significant.

Water Resources: This site is not within the BBID service area (though it is less than one-half mile from the BBID boundary), and a source of fresh water to this site has not been identified. It is possible that the site could be served by Zone 7 (Alameda County's water district), or possibly by an extension of the BBID service area. In either case, if fresh water were initially used for power plant cooling, staff would recommend requiring that the applicant to change over to reclaimed water as such water becomes available in the project area (i.e., at Mountain House). Use of fresh water would require analysis of impacts in other issue areas, depending on the source of the water and the point of diversion (e.g., fisheries impacts would be evaluated). A reclaimed water pipeline would have to be constructed for this purpose. Also, a stream runs through this parcel, so if it could not be avoided, engineering design options to carry flow would need to be evaluated to reduce the potential for flooding. The project would have to avoid the stream altogether or otherwise obtain a streambed alteration permit from the California Department of Fish and Game, which could be difficult depending on potential stream impacts.

Noise: Ambient noise levels in the general vicinity of this site are relatively low, except along Mountain House Road, where heavy truck traffic dominates the noise environment during daytime hours. Noise emanating from the power plant to the nearest sensitive receptor would be shielded to a great extent by the intervening topography, giving it an advantage over the project site.

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BRUNS ROAD SITE

The Bruns Road Site (applicant's alternative Site 5) is located west of the proposed project site between the California Aqueduct and the Delta Mendota Canal and immediately northwest 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 BBID corporation yard. The site is approximately 1,500 feet east of the BBID yard. 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 an undeveloped 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.

Two transmission lines cross the alternative site in a north to south direction. PG&E's 500-kV transmission lines cross the western border of the site and Western's 230-kV transmission line crosses the eastern border of the site. 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 (shorter than the line required for the proposed project). The water supply line would require a 3,000-foot-long pipeline to connect to the BBID takeoff point.

The project lies in an area identified by the Contra Costa County Airport Land Use Compatibility Plan (EAEC 2001a, Section 9) as Zone B2. The closest airport is the Byron Airport, located 3 miles north of the site at 3000 Armstrong Road in Byron. The B2 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 (EAEC 2001).

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. Wind farms are located on the hills to the west of the site and numerous transmission lines converge on Tracy Substation located to the southeast of the Bruns Road Site. The site would be most visible to southbound travelers on Byron-Bethany Road and Bruns Road. Views of the site from northbound Byron-Bethany Road would be partially screened by the levee of the Delta Mendota Canal. 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 corporation yard is located.

Bruns Road Site Impact Discussion

Air Quality: This site is located in the BAAQMD and in close proximity to the proposed project, so potential impacts would be similar to those of the proposed project.

Biological Resources: This site contains a portion of annual grasslands, which could be suitable habitat for sensitive biological resources. Furthermore, the eastern edge of the Red-Legged Frog Recovery "Core" Area borders the annual grassland (EAEC 2001a). The site's proximity to the Red-Legged Frog Recovery "Core" Area and the presence of annual grasslands on a portion of the site could result in impacts due to habitat loss and degradation if a power plant were constructed at this location. Like the proposed project, this site also contains San Joaquin kit fox habitat. A power plant at this location would likely have a greater effect on high value habitat than at the proposed project location.

Cultural Resources: To determine potential impacts of a project at this site, a background search at the regional CHRIS and a survey of both archaeological and historic resources would be necessary. At this time, staff has not identified any conditions or resources that indicate the potential for the creation of significant impacts, nor any potential advantages over the proposed project.

Hazardous Materials: The risk associated with use and transport of anhydrous ammonia and other hazardous materials at the Bruns Road Site would be similar to that of the proposed project (less than significant). However, this site has possible residences nearby, so the potential for impacts would be slightly greater than for the proposed project. Because Contra Costa County prohibits the aboveground storage of bulk hazardous materials, additional mitigation would likely be required for compliance with LORS.

Land Use and Soils: Like the proposed project site, this land is zoned Agricultural and is designated as "Unique Farmland." As with the proposed site, the project may not be consistent with the County's land use designation and zoning for the Bruns Road site. Also, the current development pattern for the area established by the ECAP, as amended by Measure D, is unclear and would need to be reviewed. Mitigation, in the form of an agricultural management plan for the preservation of agricultural land off- and potentially on-site, would likely be required. In addition, because of its proximity to Byron Airport, this site would require a review for potential impacts of stack height on navigable space, as well as a permit from Contra Costa County. However, it should be noted that the Bruns Road Site and the proposed site are similar distances to the airport, and at the proposed site, the FAA completed an aeronautical study that determined that there would be no hazard to navigation.

Transmission System Engineering: The Bruns Road site is located off Bruns Road, between a double circuit 230-kV transmission line coming into the Tracy substation and two 500-kV transmission lines. The double circuit 230-kV transmission line adjacent to the site appears to contain the two Tracy-Hurley 230-kV circuits, each rated at 319 MVA (normal and emergency). These existing circuits do not have enough capacity to handle 1,100 MW. This double circuit 230-kV line would have to be rebuilt from Tracy to Hurley to accommodate a 1,100 MW generating plant. The two 500-kV transmission lines adjacent to the site as candidates for interconnection are the two Table Mountain–Tesla 500-kV lines, each with a normal rating of 2,310 MVA and an emergency rating of 3,463 MVA. Again, either of these 500-kV transmission lines may be able to handle a 1,100 MW generating plant depending on the amount of power already dispatched on them. In summary, there may be enough transmission capacity to connect 1,100 MW at the Bruns site to the nearest existing 500-kV transmission line. It would be costly to install a 500-kV switchyard. However, this would likely be less expensive than the required upgrade of the 230-kV Tracy-Hurley line and substation terminations. An additional significant concern is that connections to California's backbone 500 kV system by generating units can be very difficult due to concerns about system reliability.

Visual Resources: The overall visual quality of the Bruns Road site is low-to-moderate, reflecting the substantial influence of the numerous transmission lines crossing and adjacent to the site. Viewer concern is rated moderate-to-high, as travelers on Byron-Bethany Road anticipate open, panoramic views of a predominantly agricultural setting with the prominent forms of the power transmission facilities and associated industrial character. However, the addition of prominent geometric forms with significant mass that would block views of the Coast Range foothills to the west and south would be perceived as an adverse visual change. Project visibility would be moderate-to-high in the foreground of views from Byron-Bethany Road. The number of viewers would be high and the duration of view would be moderate. Overall viewer exposure would be moderate-to-high. The overall visual sensitivity of the existing landscape and viewing characteristics would be moderate.

The use of the Bruns Road Site for a power plant would result in the introduction of linear and geometric forms of industrial character. Although the linear forms and lines of the project would be similar to that of the adjacent electric transmission infrastructure and nearby wind farms, the solid geometric mass of the structures would be substantially different. The resulting visual contrast would be moderate-to-high. The project would appear co-dominant-to-dominant and view blockage would be moderate-to-high. The overall visual change resulting from the use of the site would be moderate-to-high. 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 occur at the Bruns Road Site would cause an adverse and significant visual impact.

Visible Plumes: The production of frequent and sizable water vapor plumes at this location would introduce prominent industrial features that would be visible from local and regional vantage points and would temporarily block views of portions of the Coast Range foothills and regional landmarks including Brushy Peak and Mount Diablo for some viewers. The number of viewers and duration of view would be low-to-moderate. Considering the relatively short duration of plumes during the day for only the coolest months of the year, and the overall viewer sensitivity, the resulting visual impact would be less than significant.

Water Resources: The water supply impacts resulting from the proposed project would also occur at this site. It is assumed that this site would use the same water as the proposed site due to its proximity to that site. Similar to the proposed project, staff would recommend requiring the use of an increasing amount of reclaimed water over time since the use of fresh water would be unacceptable after reclaimed water becomes available. A water pipeline would have to be built for this purpose.

Noise: Ambient noise levels are expected to be relatively low, in the same range as for the proposed project site. Extensive noise mitigation would be required to ensure insignificant noise impacts at the mobile home and trailers located immediately south of the parcel. Alternatively, these units could be relocated to avoid the noise impacts. At the home southwest of the site, noise mitigation may be feasible, but will require attention to plant design, in a manner similar to the proposed project site. The potentially significant noise impact of the proposed project would also apply to this site, exacerbated by the immediate proximity of the mobile home and trailers.

LODI SITE

The Lodi Site was identified by staff, and is a 52-acre site located about 30 miles north of the proposed EAEC site, just west of Interstate 5 (I-5) and adjacent to the City of Lodi's White Slough Pollution Control Plant (WSWPCF) and the Northern California Power Authority's (NCPA) 50 MW Combustion Turbine No. 2 project. The City of Lodi currently owns approximately 1,000 acres in the area, 30 acres of which are used by the WSWPCF and 900 acres of which are leased to local farmers for agricultural uses. The WSWPCF is currently screened from views from the I-5 and other roadways to the east by a row of mature trees along the plant's eastern boundary. These trees would also provide some screening for a power plant.

The site is located off of North Thornton Road, southwest of the City of Lodi in San Joaquin County. The site is zoned Public and is currently used for agriculture; however, the City of Lodi is willing to negotiate other uses for the land (WSWPCF 2002).

The alternative power plant site would be just east of the NCPA plant and is accessible via existing paved roads. However, upgrades or reinforcement of the existing roads would likely be required to support heavy load trucks during construction. The site has very shallow groundwater and is at approximately zero feet of elevation and would thus require a significant amount of dirt fill to raise the site above the 100-year flood level (WSWPCF 2002).

The NCPA is adjacent to two high voltage transmission circuits, one a 230-kV double-circuit line owned by PG&E and a single circuit 230-kV line owned by Western. The existing natural gas pipeline that serves the NCPA facility and the WSWPCF does not have sufficient capacity to supply a 1,100 MW power plant. PG&E Line 108 is approximately three and one-half miles east of the alternative site; however, the line would likely need to be reinforced to serve a 1,100 MW power plant (PG&E 2002). Ground disturbance for construction of a natural gas transmission line to connect with Line 108 would increase the potential for impacts to archaeological and biological resources.

The WSWPCF could now supply enough undisinfected secondary-treated recycled water to meet the needs of a large power plant. Currently, during summer months, recycled water is committed to agricultural use, but plant management indicated that this commitment of water could be changed to allow a power plant to use reclaimed water year-round. Water provision terms would be defined in agreements between the City of Lodi and a power plant developer.

The nearest residential sensitive receptors would be more than a mile away, beyond the agricultural fields to the east. The regional landscape is defined by the flat landform of the San Joaquin Valley floor and is rural-agricultural in character. As a result, the site is highly visible from both north and southbound directions of travel on I-5 and from substantial distances in all directions from the project site.

Just west of the alternative site, beyond a 20-acre parcel used for agriculture, is the White Slough Wildlife Area (WSWA). The WSWA is under the jurisdiction of the California Department of Water Resources but is managed by the California Department of Fish and Game. The WSWA land adjacent to the City of Lodi property line contains unconnected canal ponds that are frequented by recreational fishermen. In addition, the WSWPCF evaporation ponds located just east of the site are frequented by birdwatchers throughout the year because the ponds are heavily used by migratory waterfowl (WSWPCF 2002).

Lodi Site Impact Discussion

Air Quality: This site is located in the SJVAPCD, unlike the proposed site, the Mountain House Site, and the Bruns Road Site, which are all in the BAAQMD. Therefore, the Lodi Site would be subject to the mitigation requirements of the SJVAPCD. Offsets would likely be closer to the area directly affected by plant emissions. Additional construction impacts may result at this site due to the need to import large quantities of soil for a raised foundation, but these impacts would be mitigable to less than significant levels with implementation of standard mitigation.

Biological Resources: Potential impacts of construction and operation on the many species occupying the nearby WSWA would need to be evaluated. Construction or operation of a large power plant at this location may disturb the migratory waterfowl that use the water treatment ponds of the WSWPCF. Because there are trees present both east of the WSWPCF and along the slough just west of the site, predator perching opportunities already exist on both sides of the site, thereby making this site poor quality habitat for kit fox. Additional screening may be required, but because trees already are present adjacent to the site, any new trees would present only an incremental increase in perching opportunities. Due to the proximity of this site to the waterfowl areas, this alternative could result in more impacts than the proposed project.

Cultural Resources: To determine potential impacts of a project, a background search at the regional CHRIS and a survey of both archaeological and historic resources would be necessary. The total length of gas and water pipelines would be similar to the proposed project, thus the two sites would have similar ground disturbance. In addition, the Lodi Site would be located on disturbed agricultural land without waterways or structures, so the potential for significant cultural resources impacts is low.

Land Use: Although used for agriculture, this site is zoned Public and is not designated for agricultural use.

Hazardous Materials: Based on the rural location of this site and easy truck-route access to I-5, the risk associated with anhydrous ammonia and other hazardous materials would likely be less than those at the proposed site and the other alternatives.

Transmission System Engineering: It appears feasible to connect 1,100 MW to the existing 230-kV transmission system corridor at the Lodi site. However, a 230-kV switching station would have to be installed at the Lodi site to connect to all of the 230-kV lines, and there may be transmission constraints or other significant issues in dealing with PG&E, the ISO, and possibly Western in order to deliver the power into the PG&E system. A system impact study would need to be performed to confirm technical and economic feasibility.

Visual Resources: The overall visual quality of the immediate project site is low-to-moderate, reflecting the influence of nearby electric transmission infrastructure, the existence of the NCPA generation facility, the dominance of the I-5 transportation infrastructure, and the relatively non-distinct character of the surrounding agricultural lands. Viewer concern is rated moderate, as travelers on I-5 anticipate open, panoramic views of a predominantly non-distinct agricultural setting with the noticeable presence of power transmission and generation facilities. However, the addition of prominent geometric forms with significant mass that block views to the west of I-5 would be perceived as an adverse visual change. Project visibility would be high in the foreground of views from I-5. The number of viewers would be high and the duration of view would be moderate-to-extended. Overall viewer exposure would be high. The overall visual sensitivity of the existing landscape and viewing characteristics would be moderate.

The use of the Lodi Site for a power plant would result in the introduction of linear and geometric forms of industrial character. The linear forms and lines of the project would be similar to that of the adjacent electric transmission infrastructure and the solid geometric mass of the structures would be similar to the adjacent 50 MW power plant though substantially larger. However, the dominant character of the project site and region is that of rural agricultural uses. The resulting visual contrast would be moderate-to-high. The project would be the dominant form in the project vicinity and view blockage of the agricultural lands to the west of I-5 would be moderate. The overall visual change resulting from the use of this site would be moderate-to-high. 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 occur at this site would cause an adverse and significant visual impact. It is possible that mitigation such as additional landscaping could reduce this impact to less than significant, but this cannot be determined with certainty without more detailed study and analysis of photosimulations.

Visible Plumes: The production of frequent and sizable plumes at this location would introduce prominent industrial features that would be visible from local and regional vantage points at substantial viewing distances. Because of the number of viewers with unobstructed views of the plumes the resulting visual impact would likely be adverse and significant. However effective implementation of mitigation measures (i.e., plume abatement) could reduce the visual impact of vapor plumes at the Lodi Site to a level that would not be significant.

Water Resources: If this site were used, the project could use recycled water from the City of Lodi's WSWPCF, except during summer months when water is committed to agricultural use. However, plant management indicated that this commitment of water could be changed, allowing year-round supply to a power plant, depending on the agreements between the City of Lodi and a power plant developer. This change could, however, result in potential impacts in other areas. Other water supplies (e.g., groundwater or SWP water) for the agricultural uses would have to be identified. Assuming that those supply issues were resolved, this site could eliminate the water supply concerns of the proposed site. However, due to the flooding potential of the site, dirt fill would need to be imported to the site.

Noise: Ambient noise levels in the vicinity are relatively high due to traffic on I-5 and the operation of the NCPA turbine installation. The nearest homes are on the opposite side of I-5, and would not be expected to experience significant noise exposure from the power plant.

PANOCHE SITE

The Panoche Site would be located adjacent to PG&E's Panoche Substation, over 100 miles southeast of the proposed site. The Panoche Site is located on the south side of Panoche Road, on the west side of Fairfax Road, and 2.5 miles east of I-5. The site sits at approximately 400 feet of elevation.

The site is located in unincorporated Fresno County. It is an approximately 30-acre flat parcel surrounded by the Panoche Substation, a small generating facility, open space and agricultural land uses. The site is disturbed and was previously used for agriculture. The closest residence is approximately 1,700 feet away from the Panoche Site.

The PG&E-owned Panoche Substation provides 230- and 115-kV service. The Panoche Substation also marks the connection point for PG&E's backbone natural gas supply pipeline Line 300. There is sufficient natural gas supply available at the site. There is a water supply pipeline in Panoche Road; however, that water supply is intended for domestic purposes. To cool a power plant at this site, an approximately 46-mile water supply pipeline could be built to bring reclaimed water from the Fresno-Clovis Waste Water Treatment Facility (WWTF). Alternatively, dry cooling technology could be used, which would minimize cooling water requirements.

Air Quality: This site is located in the SJVAPCD, unlike the proposed site, the Mountain House Site, and the Bruns Road Site, which are all in the BAAQMD. Therefore, the Panoche Site would be subject to the mitigation requirements of the SJVAPCD. Offsets would likely be closer to the area directly affected by plant emissions. Additional construction impacts may result at this site due to the need to construct a 46-mile water supply pipeline (although dry cooling could be used instead).

Biological Resources: This site is on already disturbed agricultural/industrial lands so the potential for disturbing biological resources is less than with the proposed site. Surveys would be required to evaluate the potential for direct or indirect impacts to sensitive wildlife species.

Water Resources: A long water supply pipeline would need to be built to this site from the Fresno-Clovis WWTF. Dry cooling technology could be used, however, it would require a change in the project design.

Land Use: Like the proposed site, this land is zoned for agriculture; however, a power plant at this location would be consistent with the surrounding uses (Panoche Substation and natural gas facilities). There are few nearby residences.

Visual Resources: A power plant at this location would be consistent with the surrounding industrial uses (substation, transmission lines, and natural gas pipeline facilities). It would be visible from Panoche Road and the surrounding agricultural areas. Similar to the proposed site, the area has a rural character despite the adjacent facilities, but unlike the proposed site, the area does not have the backdrop of the scenic Altamont Hills and Brushy Peak. Therefore, this area is not considered to have as high a scenic value as the proposed site. A plant at this site would not be highly visible from I-5, which is over two miles to the west.

Visible Plumes. If wet cooling were used, frequent but short duration water vapor plumes of substantial size could occur during the coolest months of the year. Such plumes at the Panoche Road site would not be expected to result in a significant visual impact due to the distance to viewers on I-5 and the few local residents in close proximity. Therefore, this site is similar to the proposed site regarding impacts from visible plumes.

Hazardous Materials: Based on the location of this site, the risk associated with use and transport of anhydrous ammonia and other hazardous materials would be similar to that of the proposed project (less than significant). However, this site has possible residences nearby, so impacts would be slightly greater than those at the proposed project.

Cultural Resources: To determine potential impacts of a project, a background search at the regional CHRIS and a survey of both archaeological and historic resources would be necessary. The total length of the water pipeline required for this site would be longer than for the proposed project; thus, the Panoche Site would result in greater ground disturbance, increasing the potential for impacts to archeological resources. The site would be located on disturbed agricultural land adjacent to industrial structures, so the potential for significant cultural resources impacts on the site itself would be low.

Transmission System Engineering: The transmission capability at Panoche can be summarized as follows: three 230-kV lines leave the substation to the north (with a total of 917 MVA normal and 1,074 MVA emergency capacity), two 230-kV lines go west (with a total of 600 MVA normal and 688 MVA emergency capacity), and four lines go south (with a total of 1,217 MVA normal and 1,418 MVA emergency capacity). A load flow study would be required to determine the power flows on the 230-kV transmission system with 1,100 MW installed at the Panoche site during normal and emergency conditions. If the power generated at the plant were delivered to northern California, it is likely that there would be enough capacity during normal conditions, if the power splits between the north and west 230-kV transmission circuits (although for a double circuit outage condition there may be some overloads). However, if the power generated were delivered to southern California, there may not be enough capacity during normal conditions. For a double circuit outage condition there likely will be overloads on the remaining two southern 230-kV circuits.

A one half mile double circuit 230-kV line from the Panoche site to the Panoche substation would be required to inject 1,100 MW into the 230-kV transmission system. In addition, the breakers at the Panoche substation would likely have to be replaced, and the breakers at the existing generation facility adjacent to the substation would likely have to be replaced. In summary, there is probably enough existing 230-kV transmission capacity to handle a large several hundred MW generating plant at the Panoche site. A more detailed power flow study would be required to determine whether the full 1,100 MW could be installed without significant system improvements.

Noise: Ambient noise levels are relatively low, and there are a few residences within a half-mile of the site. Mitigation for plant noise, similar to that recommended at the proposed site, would likely be able to reduce noise impacts to less than significant levels.

NO PROJECT (NO ACTION) ALTERNATIVE

The “no project” alternative under CEQA and the “no action” alternative under NEPA assume that the project is not constructed. In the CEQA analysis, the “no project” alternative is compared to the proposed project and determined to be either 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 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. If this facility were not constructed, the proposed site would remain in agricultural production, and additional power to meet both the applicant’s objectives and the State’s needs would not be available. Due to market forces, the proposed facility may also serve to replace older, inefficient facilities. In addition, the East Altamont Energy Center is subject to a contract between the California Department of Water Resources (DWR) and the applicant and is considered by DWR to be an important facility for California’s electricity supply. If the “no project” alternative were 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 or the benefits noted above.

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;
Conservation and demand side management; and
Renewable resources.

Each of these alternatives, and the reasons they were not considered in detail in this analysis, are described below.

SITE ALTERNATIVES ELIMINATED FROM THIS 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 pipeline. To supply water, a new 4.6-mile waterline would be constructed from the BBID or another water source could be developed (EAEC 2001a).

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 but not completely block a power plant. 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, both of which are heavily traveled roads. Therefore, situating the power plant at Site 3 would not reduce or avoid any of 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, and 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. PG&E 500-kV electrical transmission lines cross 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 water supply pipeline would be required to connect to the BBID water takeoff 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 a heavily traveled roadway with expansive views. Therefore, visual impacts could 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 AND THE NO PROJECT (NO ACTION) ALTERNATIVE

For purposes of the NEPA process, Western has determined that none of the site alternatives analyzed under the Energy Commission alternatives analysis are consistent with Western's purposes and need to provide open access transmission service.

DOE's NEPA regulations require that an EA include a discussion of the no-action alternative (10 C.F.R. 1021.321(c)). Similar to the Energy Commission, Western must either accept the applicant's request for interconnection, or deny the request and choose the no action alternative.

The no action alternative provides a baseline against which the effects of the proposed action may be compared. In short, the site-specific and direct impacts associated with the power plant would not occur at this site if the project does not go forward. However, as noted earlier, if the plant is not built, demands for power in California would most likely result in the construction of a similar power plant at another location, or the possibility of more reliance on older and less efficient power plants through out the western United States. Identifying these indirect impacts of the no action alternative is speculative. However, two other energy facilities, Tesla Power Plant and Tracy Peaking Power Plant, have recently been proposed within six miles of the proposed project. The Tesla plant is currently undergoing review by the Energy Commission, and the Tracy plant was approved by the Energy Commission in July 2002. The fact that these two facilities have been proposed nearby helps to demonstrate the interest in and need for power plant construction. These two plants are not requesting interconnection with Western's transmission system.

Potential site-specific impacts of the EAEC are summarized in the "Potential Significant Environmental Impacts" section of this chapter. Note that Energy Commission staff has made the determination of potential significance. The Energy Commission and Western will make their own independent determinations of significance. The specific impacts described in the referenced section and through out this document would be avoided by the no action alternative, but similar impacts would occur elsewhere because of the need for a power plant.

CONSERVATION AND DEMAND SIDE MANAGEMENT

One alternative to a power generation project could consist of a program or 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)). This is because the approximate effect of such programs is already accounted for in the agency's "integrated assessment of need," and efficiency or conservation programs would not in themselves be sufficient to substitute for the additional generation calculated to be needed.

In spite of the state's success in reducing demand in 2001, California continues to grow and overall demand is increasing. The 2002-2012 Electricity Outlook Report (CEC

2002a) concludes that, despite exceptional conservation efforts in 2001, voluntary demand reduction will likely decrease over time.

While conservation and demand reduction programs are not considered as alternatives to a proposed project, the Energy Commission is responsible for several such programs, most notably the 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 aim to shift such energy use to off-peak periods.

The Energy Commission’s Energy Efficiency Standards for Residential and Nonresidential Buildings (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. The Energy Commission adopted new standards in 2001, as mandated by Assembly Bill 970 to reduce California’s electricity demand. The new standards went into effect on June 1, 2001. Since 1975, the displaced peak demand from these conservation efforts has amounted to roughly the equivalent of eighteen 500 MW power plants. The annual impact of building and appliance standards has increased steadily, from 600 MW in 1980 to 5,400 MW in 2000, as more buildings and homes are built under increasingly efficient standards (CEC 2002a).

After the California Independent System Operator (Cal-ISO) ordered rolling blackouts in January 2001 as a result of statewide electricity shortages, conservation efforts initially resulted in dramatic reductions in electricity use. Electricity use for each month in 2001 ranged from 5 percent to 12 percent less than it was in 2000. However, in 2002 demand has been increasing as the memories of rolling blackouts fade.

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 five and 12 year forecasts of both energy supply and demand. The Energy 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 2002-2012 Electricity Outlook Report (available on the Energy Commission’s website).

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, and the potential for these facilities to be used instead of the proposed gas-fired plant. 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 can cause environmental impacts and have feasibility problems.

Geothermal. Geothermal technologies use steam or high-temperature water (HTW) obtained from naturally occurring geothermal reservoirs to drive steam turbine/generators. The technology relies on either a vapor dominated resource (dry, super-heated steam) or a liquid-dominated resource to extract energy from the HTW. Geothermal is a commercially available technology, but it is limited to areas where geologic conditions result in high subsurface temperatures. There are no geothermal resources in the project vicinity, making this technology an infeasible alternative.

Biomass. Biomass generation uses a waste vegetation fuel source such as wood chips (the preferred source) or agricultural waste. The fuel is burned to generate steam. Biomass facilities generate substantially greater quantities of air pollutant emissions than natural gas burning facilities, though these emissions may be partially offset by the reduction in emissions from open-field burning of these fields. In addition, biomass plants are typically sized to generate less than 20 MW, which is substantially less than the capacity of the 1,100 MW EAEC project. In order to generate 1,100 MW, which is proposed for the EAEC, fifty-five 20 MW biomass facilities would be required. However, these power plants would have potentially significant environmental impacts of their own.

Solar. Currently, there are two types of solar generation available: solar thermal power and photovoltaic (PV) power generation.

Solar thermal power generation uses high temperature solar collectors to convert the sun's radiation into heat energy, which is then used to run steam power systems. Solar thermal is suitable for distributed or centralized generation, but requires far more land than conventional natural gas power plants. Solar parabolic trough systems, for instance, use approximately five acres to generate one megawatt.

Photovoltaic (PV) power generation uses special semiconductor panels to directly convert sunlight into electricity. Arrays built from the panels can be mounted on the ground or on buildings, where they can also serve as roofing material. Unless PV systems are constructed as integral parts of buildings, the most efficient PV systems require about four acres of ground area per megawatt of generation.

Solar resources would require large land areas in order to meet the project objective to generate 1,100 MW of electricity. For example, assuming that a parabolic trough system was located in a maximum solar exposure area, such as in a desert region, generation of 1,100 MW would require 5,500 acres. For a PV plant, generation of 1,100 MW would require 4,400 acres.

While solar generation facilities do not generate problematic air emissions and have relatively low water requirements, there are other potential impacts associated with their use. Construction of solar thermal plants can lead to habitat destruction and visual impacts. PV systems can also have negative visual impacts, especially if ground-mounted. Furthermore, PV installations are highly capital intensive, and manufacturing of the panels generates some hazardous wastes.

Both solar thermal and PV facilities generate power during peak usage periods since they collect the sun's radiation during daylight hours. However, even though the use of solar technology may be appropriate for some peaker plants, solar energy technologies cannot provide full-time availability due to the natural intermittent availability of solar resources. Therefore, solar generation technology would not meet the project's goal, which is to provide immediate power to meet peaks in demand.

Wind. Wind carries kinetic energy that can be utilized to spin the blades of a wind turbine rotor and an electrical generator, which then feeds alternating current (AC) into the utility grid. Most state-of-the-art wind turbines operating today convert 35 to 40 percent of the wind's kinetic energy into electricity. Modern wind turbines represent viable alternatives to large bulk power fossil power plants as well as small-scale distributed systems. The range of capacity for an individual wind turbine today ranges from 400 watts up to 3.6 MW. California's 1,700 MW of wind power represents 1.5 percent of the state's electrical capacity.

Although air emissions are significantly reduced or eliminated for wind facilities, they can have significant visual effects. Also, wind turbines can cause bird mortality (especially for raptors) resulting from collision with rotating blades.

Wind resources would require large land areas in order to generate 1,100 MW of electricity. Depending on the size of the wind turbines, wind generation "farms" generally require between five and 17 acres to generate one megawatt (resulting in the need for between 5,500 and 18,700 acres to generate 1,100 MW) (CEC 2001c). Although 7,000 MW of new power wind capacity could cost-effectively be added to California's power supply, the lack of available transmission access is an important barrier to wind power development (Beck 2001). California has a diversity of existing and potential wind resource regions that are near load centers such as San Francisco, Los Angeles, San Diego and Sacramento (CEC 2001d). However, wind energy technologies cannot provide full-time availability due to the natural intermittent availability of wind resources. Therefore, wind generation technology would not meet the project's goal, which is to provide immediate power to meet peaks in demand.

Hydroelectric Power. While hydropower does not require burning fossil fuels and may be available, this power source can cause significant environmental impacts primarily due to the inundation of many acres of potentially valuable habitat and the interference with fish movements during their life cycles. As a result of these impacts, it is extremely unlikely that new hydropower facilities could be developed and permitted in California within the next several years.

Conclusion Regarding Renewable Resources. The renewable technologies discussed above have the advantage of not requiring the burning of fossil fuels and avoiding 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. Furthermore, renewable resources are not consistent with Western's purposes and need to provide non-discriminatory open transmission access.

CONCLUSIONS

As determined by Energy Commission staff, this project as proposed would cause potential impacts in air quality, land use, biology, cultural resources, visual resources, soil and water resources, and noise. For all areas except visual resources, staff is recommending measures to mitigate impacts to less than significant. Following is a summary of the advantages and disadvantages of the four alternative sites and the no project alternative compared to the proposed project.

Mountain House Site. This site would have similar impacts to the proposed site in the issue areas of air quality, hazardous materials, transmission system engineering, and water and soil resources. It would potentially have fewer impacts than the proposed project in the areas of visual resources and noise, but could have greater impacts in cultural resources because of potential impacts associated with historic structures. As with the proposed site, the project may not be consistent with land use and zoning. There are also potential significant impacts to biological resources because the project would be closer than the proposed site to the California red-legged frog "Core" Recovery Area, wetlands, and vernal pools.

Bruns Road Site. This site would have similar impacts to the proposed project in the disciplines of cultural resources, hazardous materials, water and soil, transmission system engineering, and noise. Like the proposed project, the use of fresh water would be unacceptable so a plant at this site would also be required to use reclaimed water when it became available. It would potentially have fewer impacts in land use because it would be farther from the school on Mountain House Road. However, there would be potentially significant visual impacts because the structures would contrast with the surrounding area and be visible from area roads. Construction impacts on air quality would be less than for the proposed site because the water and gas pipelines would be shorter. It could have potentially significant biological impacts because it would be located in San Joaquin kit fox habitat as well as nearby to the California red-legged frog "Core" Recovery Area.

Lodi Site. This site would have similar impacts to the proposed project in the issue area of hazardous materials. Based on past and present land use and linear requirements, this site is similar to the proposed project for cultural resources. This site would potentially have fewer impacts than the proposed project for air quality, water and soil, and noise and has the least potential for impacts. However, there would be potentially significant impacts to visual resources. In addition, a transmission study would be required to evaluate impacts on the regional transmission system and a biological assessment would be necessary to evaluate potentially significant impacts to species in the WSWA and the WSWPCF ponds.

Panoche Site. This site would have similar impacts to the proposed project in the issue area of hazardous materials. It would potentially have fewer impacts than the proposed project in terms of land use, because although it is zoned agricultural, the plant would be located in an area with existing industrial development. The site would also have potentially less impacts than the proposed site for biological resources, noise, and visual resources. While the potential impacts are less than at the proposed site for air quality (because it would be located in the SJVAPCD), the construction impacts on air quality based on the length of the required water pipeline would be greater than for the proposed project unless dry cooling were used. The length of the required pipeline would result in this site having greater potential impacts than the proposed project in terms of water and soil resources and cultural resources. Transmission would likely be feasible from this site and the adjacent substation, but a power flow study would be necessary.

No Project. While the impacts of the proposed project would not occur with the no project alternative, the benefits of the project would also be eliminated. These benefits include the potential for elimination of older, less efficient power plants. In addition, the no project alternative would not meet the contractual requirements with the DWR to provide electricity to the State of California.

SUMMARY

The Staff Assessment currently finds a potential unmitigable significant adverse impact of the proposed project in visual resources. This impact could best be reduced at the Mountain House or Panoche Sites. However, each of the alternative sites has the potential to create other impacts, especially in biological, and cultural resources, and these issues would require more detailed study. The Lodi Site seems to offer the best potential for minimizing impacts in most disciplines and it has reclaimed water available for cooling (although the provision of that water during summer months would have to be negotiated), but it would have visual impacts similar to those of the proposed project. The Panoche Site is slightly better than the Lodi Site because of the reduced visual impacts and lack of nearby waterfowl habitat, but there is no water available, so it would require use of dry cooling or construction of a 46-mile reclaimed water pipeline, which could result in other potential impacts. Overall, the four site alternatives considered in this section offer some advantages and disadvantages in comparison to the proposed project. However, none of the alternative sites appear to reduce the potentially significant adverse impacts of the project without causing additional potentially significant impacts themselves. Also, use of any alternative site would be inconsistent with the objective of being online in 2005, and satisfying the applicant's contractual requirements with the DWR.

For purposes of the NEPA process, Western has determined that none of the siting alternatives analyzed under the staff alternatives analysis are consistent with Western's purposes and need to provide non-discriminatory open transmission line access.

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GENERAL CONDITIONS
INCLUDING
COMPLIANCE MONITORING AND CLOSURE PLAN

Testimony of 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 compliance 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 elements that:

- set forth the duties and responsibilities of the Compliance Project Manager (CPM), the project owner, delegate agencies, and others;
- set forth the requirements for handling confidential records and maintaining the compliance record;
- state procedures for settling disputes and making post-certification changes;
- state the requirements for periodic compliance reports and other administrative procedures that are necessary to verify the compliance status for all Energy Commission approved conditions;
- establish requirements for facility closure plans.
- 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 assuring 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 construction 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:

the installation of environmental monitoring equipment;

a soil or geological investigation;

a topographical survey;

any other study or investigation to determine the environmental acceptability or feasibility of the use of the site for any particular facility; or

any work to provide access to the site for any of the purposes specified in a., b., c., or d.

START OF COMMERCIAL OPERATION

For compliance monitoring purposes, “commercial operation” is that phase of project development which begins after the completion of start-up and commissioning, where the power plant has reached steady-state production of electricity with reliability at the rated capacity. For example, at the start of commercial operation, plant control is usually transferred from the construction manager to the plant operations manager.

COMPLIANCE PROJECT MANAGER RESPONSIBILITIES

A Compliance Project Manager (CPM) will oversee the compliance monitoring and shall be responsible for:

1. ensuring that the design, construction, operation, and closure of the project facilities are in compliance with the terms and conditions of the Energy 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 the approval will involve all appropriate staff and management.

The Energy Commission has established a toll free compliance telephone number of **1-800-858-0784** for the public to contact the Energy 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 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 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):

- all documents demonstrating compliance with any legal requirements relating to the construction and operation of the facility;
- all monthly and annual compliance reports filed by the project owner;
- all complaints of noncompliance filed with the Energy Commission; and
- all petitions for project or condition changes and the resulting staff or Energy Commission action.

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. A summary of the General Conditions of Certification is included as **Compliance Table 1** at the conclusion of this section. The designation after each of the following summaries of the General Compliance Conditions (**Com-1, Com-2,** etc.) refers to the specific General Compliance Condition contained in **Compliance Table 1.**

Western Responsibilities

Western's responsibilities will include establishing conditions and ensuring compliance with those conditions for the electric transmission portions of the project that are under federal ownership and operation.

By voluntarily agreeing to a joint analysis process with the Energy Commission and to any Conditions of Certification imposed by the Energy Commission for approval of the project, Western is not ceding any jurisdictional authority over federal facilities to the State of California.

Access, Compliance Condition of Certification-1 (COM-1)

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, COM-2

The project owner shall maintain project files onsite or at an alternative site approved by the CPM, for the life of the project unless a lesser period of time is specified by the conditions of certification. The files shall contain copies of all "as-built" drawings, all documents submitted as verification for conditions, and all other project-related documents.

Energy Commission staff and delegate agencies shall, upon request to the project owner, be given unrestricted access to the files.

Reporting of Unplanned Outages, COM-3

Throughout the life of the project, the project owner shall immediately report all unplanned outages, via e-mail to the Compliance Program Manager and to the CPM. The expected duration and reason for the outage shall be included in the report. Telephone communication is also encouraged. Contact shall be made as follows:

Compliance Program Manager
E-mail**:** cnajaria@energy**.**state**.**ca**.**us telephone: (916) 654-4079

Compliance Project Manager
E-mail: ilewis@energy.state.ca.us telephone: (916) 654-4678

Compliance Verification Submittals, COM-4

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. providing appropriate letters from delegate agencies verifying compliance;
3. Energy Commission staff audits of project records; and/or
4. Energy Commission staff inspections of mitigation 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.

Pre-Construction Matrix and Tasks Prior to Start of Construction COM-5

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 or prior to the first pre-construction meeting, whichever comes first. It will be in the same format as the compliance matrix referenced above.

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. Various lead times (e.g., 30, 60, 90 days) for submittal of compliance verification documents 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.

Failure to submit compliance documents within the specified lead-time may result in delays in authorization to commence various stages of project development.

Project owners frequently anticipate starting project construction as soon as the project is certified. In those cases, it may be necessary for the project owner to file compliance submittals prior to project 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 the submittal of compliance documents prior to project certification is at the owner's own risk. Any approval by Energy Commission staff is subject to change based upon the Final Decision

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, COM-6

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 of each condition (e.g., "not started," "in progress" or "completed" (include the date); and
8. the project's pre-construction and construction milestones, including dates and status.

Satisfied conditions do not need to be included in the compliance matrix after they have been identified as satisfied in at least one monthly or annual compliance report.

MONTHLY COMPLIANCE REPORT, COM-7

The first Monthly Compliance Report is due one 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 Form 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 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 pre-construction and construction milestones (fully satisfied 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.

ANNUAL COMPLIANCE REPORT, COM-8

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;
7. a projection of project compliance activities scheduled during the next year;
8. a listing of the year's additions to the on-site compliance file;
9. an evaluation of the on-site contingency plan for unplanned facility closure, including any suggestions necessary for bringing the plan up to date [see General Conditions for Facility Closure addressed later in this section]; and
10. a listing of complaints, notices of violation, official warnings, and citations received during the year, a description of the resolution of any resolved complaints, and the status of any unresolved complaints.
11. a listing of all outages planned for the coming year and a listing of all outages that occurred during the previous year, including the anticipated duration and the reason for each outage occurrence.

CONSTRUCTION AND OPERATION SECURITY PLAN, COM-9

Prior to commencing construction, a site-specific Security Plan for the construction phase shall be developed and maintained at the project site. Prior to commercial operation, a site-specific Security Plan for the operational phase shall be developed and maintained at the project site. The plans may be reviewed at the site by the CPM during compliance inspections.

Construction Security Plan

The Construction Security Plan must address:

1. site fencing enclosing the construction area;
2. use of security guards;
3. check-in procedure or tag system for construction personnel and visitors;

4. protocol for contacting law enforcement and the CPM in the event of suspicious activity or emergency; and
5. evacuation procedures.

<u>Operation Security Plan</u>

The Operations Security Plan must address:

1. permanent site fencing and security gate;
2. use of security guards;
3. security alarm for critical structures;
4. protocol for contacting law enforcement and the CPM in the event of suspicious activity or emergency;
5. evacuation procedures;
6. perimeter breach detectors and on-site motion detectors;
7. video or still camera monitoring system; and
8. fire alarm monitoring system.

The CPM may authorize modifications to these measures, or may require additional measures depending on circumstances unique to the facility, and in response to industry-related security concerns.

CONFIDENTIAL INFORMATION, COM-10

Any information that 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, that 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, COM-11

Pursuant to the provisions of Fish and Game Code Section 711.4, the project owner shall pay a filing fee in the amount of $850. The payment instrument shall be provided to the Energy Commission's Project Manager (PM), not the CPM, at the time of project certification and shall be made payable to the California Department of Fish and Game. The PM 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, COM-12

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:

http://www.energy.ca.gov/sitingcases/power_plants_contacts.html

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 (Attachment A).

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 that provide the flexibility to deal with the specific situation and project setting that exist at the time of closure. Laws, Ordinances, Regulations and Standards (LORS) pertaining to facility closure are identified in the sections dealing with each technical area. Facility closure will be consistent with LORS in effect at the time of closure.

There are at least three circumstances in which a facility closure can take place, planned closure, unplanned temporary closure and unplanned permanent closure**.**

CLOSURE DEFINITIONS

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.

Unplanned Temporary Closure

An unplanned temporary closure occurs when the facility is closed suddenly and/or unexpectedly, on a short-term basis, due to unforeseen circumstances such as a natural disaster or an emergency.

Unplanned Permanent Closure

An unplanned permanent closure occurs if the project owner closes the facility suddenly and/or unexpectedly, on a permanent basis. This includes unplanned closure where the owner remains accountable for implementing the on-site contingency plan. It can also include unplanned 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, COM-13

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 consult with Western on the closure plan. The plan shall address impacts to Western's facilities and operations. 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.

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 Energy 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 Energy 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 Energy Commission approval of the facility closure plan is obtained.

Unplanned Temporary Closure/On-Site Contingency Plan, COM-14

In order to ensure that public health and safety and the environment are protected in the event of an unplanned 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 impacts 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 unplanned 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 unplanned temporary closure, the project owner shall notify the CPM, as well as other responsible agencies, by telephone, fax, or e-mail, 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 an unplanned temporary closure is likely to be permanent, or for a duration of more than twelve months, a closure plan consistent with the requirements 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).

Unplanned Permanent Closure/On-Site Contingency Plan, COM-15

The on-site contingency plan required for unplanned temporary closure shall also cover unplanned permanent facility closure. All of the requirements specified for unplanned temporary closure shall also apply to unplanned 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 unplanned permanent closure, the project owner shall notify the CPM, as well as other responsible agencies, by telephone, fax, or e-mail, 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 the requirements for a planned closure, shall be developed and submitted to the CPM within 90 days of the permanent closure or another period of time agreed to by the CPM.

CBO DELEGATION AND AGENCY COOPERATION

In performing construction and operation monitoring of the project, Commission staff acts as, and has the authority of, the Chief Building Official (CBO). Commission staff may delegate CBO responsibility to either an independent third party contractor or the local building official. Commission staff retains CBO authority when selecting a delegate CBO including enforcing and interpreting state and local codes, and use of discretion, as necessary, in implementing the various codes and standards.

Commission staff may also seek the cooperation of state, regional and local agencies that have an interest in environmental control when conducting project monitoring.

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 Energy Commission Decision. The specific action and amount of any fines the Energy 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, oversight, unforeseeable events, and other factors the Energy Commission may consider. Moreover, to ensure compliance with the terms and conditions of certification and applicable LORS, 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 the 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 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 48 hours, followed by a written report filed within seven 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 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 agencies 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 Energy Commission shall have the authority to consider all relevant facts involved and make any appropriate orders consistent with its jurisdiction (Cal. Code Regs., tit. 20, §§ 1232-1236).

POST CERTIFICATION CHANGES TO THE ENERGY COMMISSION DECISION: AMENDMENTS, INSIGNIFICANT PROJECT CHANGES AND VERIFICATION CHANGES, COM-16

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 Energy 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, or 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 <u>not</u> 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

As provided in Title 20, Section 1770 (d), California Code of Regulations, a verification may be modified by staff without requesting an amendment to the decision if the change does not conflict with the conditions of certification.

KEY EVENTS LIST, COM-7

PROJECT: **East Altamont Energy Center Project**

DOCKET: #: 01-AFC4

COMPLIANCE PROJECT MANAGER: Ila Lewis

EVENT DESCRIPTION	DATE
Certification Date/Obtain Site Control	
Online Date	
POWER PLANT SITE ACTIVITIES	
Start Site Mobilization	
Start Ground Disturbance	
Start Grading	
Start Construction	
Begin Pouring Major Foundation Concrete	
Begin Installation of Major Equipment	
Completion of Installation of Major Equipment	
First Combustion of Gas Turbine	
Start Commercial Operation	
Complete All Construction	
TRANSMISSION LINE ACTIVITIES	
Start T/L Construction	
Synchronization with Grid and Interconnection	
Complete T/L Construction	
FUEL SUPPLY LINE ACTIVITIES	
Start Gas Pipeline Construction and Interconnection	
Complete Gas Pipeline Construction	
WATER SUPPLY LINE ACTIVITIES	
Start Water Supply Line Construction	
Complete Water Supply Line Construction	

TABLE 1
COMPLIANCE SECTION
SUMMARY of GENERAL CONDITIONS OF CERTIFICATION

CONDITION NUMBER	PAGE #	SUBJECT	DESCRIPTION
COM-1	4	Access	The project owner shall grant Energy Commission staff and delegate agencies or consultants unrestricted access to the power plant site.
COM-2	4	Compliance Record	The project owner shall maintain project files on-site. Energy Commission staff and delegate agencies shall be given unrestricted access to the files.
COM-3	4	Reporting of Unplanned Outages	Throughout the life of the project, the project owner shall immediately report all unplanned outages.
COM-4	4	Compliance Verification Submittals	The project owner is responsible for the delivery and content of all verification submittals to the CPM, whether such condition was satisfied by work performed or the project owner or his agent.
COM-5	5	Pre-construction Matrix and Tasks Prior to Start of Construction	Construction shall not commence until the all of the following activities/submittals have been completed: property owners living within one mile of the project have been notified of a telephone number to contact for questions, complaints or concerns, a pre-construction matrix has been submitted identifying only those conditions that must be fulfilled before the start of construction, all pre-construction conditions have been complied with, the CPM has issued a letter to the project owner authorizing construction.
COM-6	6	Compliance Matrix	The project owner shall submit a compliance matrix (in a spreadsheet format) with each monthly and annual compliance report which includes the status of all compliance conditions of certification.
COM-7	7	Monthly Compliance Report including a Key Events List	During construction, the project owner shall submit Monthly Compliance Reports (MCRs) which include specific information. The first MCR is due the month following the Commission business meeting date on which the project was approved and shall include an initial list of dates for each of the events identified on the Key Events List.

CONDITION NUMBER	PAGE #	SUBJECT	DESCRIPTION
COM-8	7	Annual Compliance Reports	After construction ends and throughout the life of the project, the project owner shall submit Annual Compliance Reports (ACRs) which include specific information. The first ACR is due after the air district has issued a Permit to Operate.
COM-9	8	Security Plans	Prior to commencing construction, the project owner shall submit a Construction Security Plan. Prior to commencing operation, the project owner shall submit an Operation Security Plan.
COM-10	9	Confidential Information	Any information the project owner deems confidential shall be submitted to the Commission's Dockets Unit.
COM-11	9	Dept of Fish and Game Filing Fee	The project owner shall pay a filing fee of $850 at the time of project certification.
COM-12	9	Reporting of Complaints, Notices and Citations	Within 10 days of receipt, the project owner shall report to the CPM, all notices, complaints, and citations.
COM-13	11	Planned Facility Closure	The project owner shall submit a closure plan to the CPM at least twelve months prior to commencement of a planned closure.
COM-14	12	Unplanned Temporary Facility Closure	To ensure that public health and safety and the environment are protected in the event of an unplanned temporary closure, the project owner shall submit an on-site contingency plan no less than 60 days prior to commencement of commercial operation.
COM-15	13	Unplanned Permanent Facility Closure	To ensure that public health and safety and the environment are protected in the event of an unplanned permanent closure, the project owner shall submit an on-site contingency plan no less than 60 days prior to commencement of commercial operation.
COM-16	15	Post-certification changes to the Decision	The project owner must petition the Energy Commission to delete or change a condition of certification, modify the project design or operational requirements and/or transfer ownership of operational control of the facility.

ATTACHMENT A

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.)

EAST ALTAMONT ENERGY CENTER
PREPARATION TEAM

Executive Summary ....Cheri Davis

Introduction ....Cheri Davis

Project Description ....Cheri Davis

Air Quality.. Tuan Ngo

Biological Resources.. Andrea Erichsen

Cultural Resources...Roger Mason

Hazardous Materials .... Alvin J. Greenberg, Ph.D. and Rick Tyler

Land Use ....Negar Vahidi and Eileen Allen

Noise and Vibration..Jim Buntin and Steve Baker

Public Health ....Obed Odoemelam, Ph.D.

Socioeconomics .... .James Adams

Soil and Water............................Lorraine White, John Scroggs, Jim Henneforth and John Kessler

Traffic and Transportation .... .David Flores

Transmission Line Safety and Nuisance..Obed Odoemelam, Ph.D.

Visual Resources .... Michael Clayton

Waste Management ....Obed Odoemelam, Ph.D.

Worker Safety and Fire Protection.................................Alvin J. Greenberg, Ph.D. and Rick Tyler

Facility Design...Brian Payne

Geology and Paleontology...Dr. Dal Hunter

Power Plant Efficiency ....Shahab Khoshmashrab and Steve Baker

Power Plant Reliability ....Shahab Khoshmashrab and Steve Baker

Transmission System Engineering .... Ajoy Guha, P.E and Al McCuen

Alternatives .... Susan V. Lee

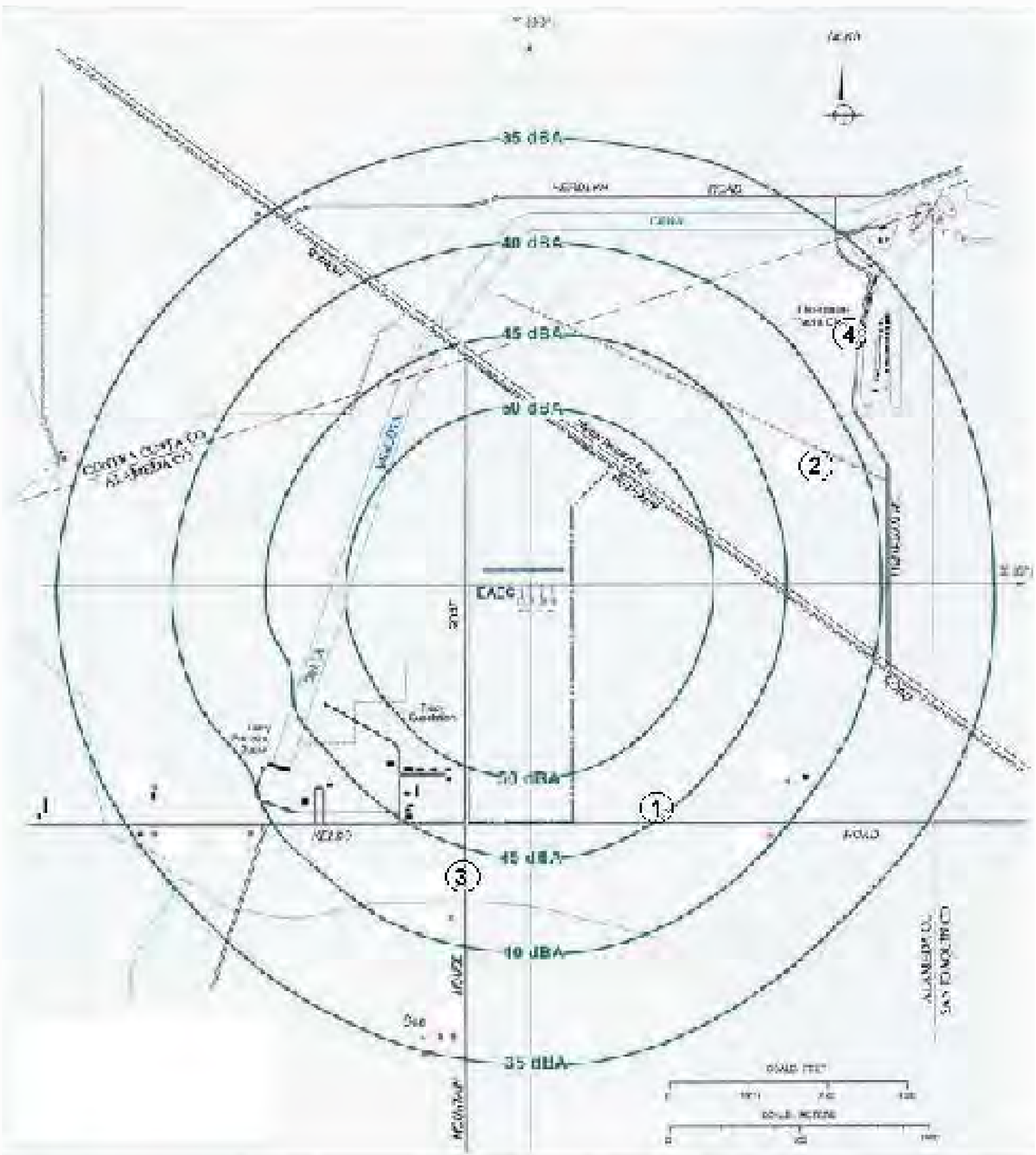
General Conditions .... Ila Lewis

Project Assistant .... Raquel Rodriguez

Support Staff .... Sean Bryant and Angie Hockaday

NOISE - Figure 1

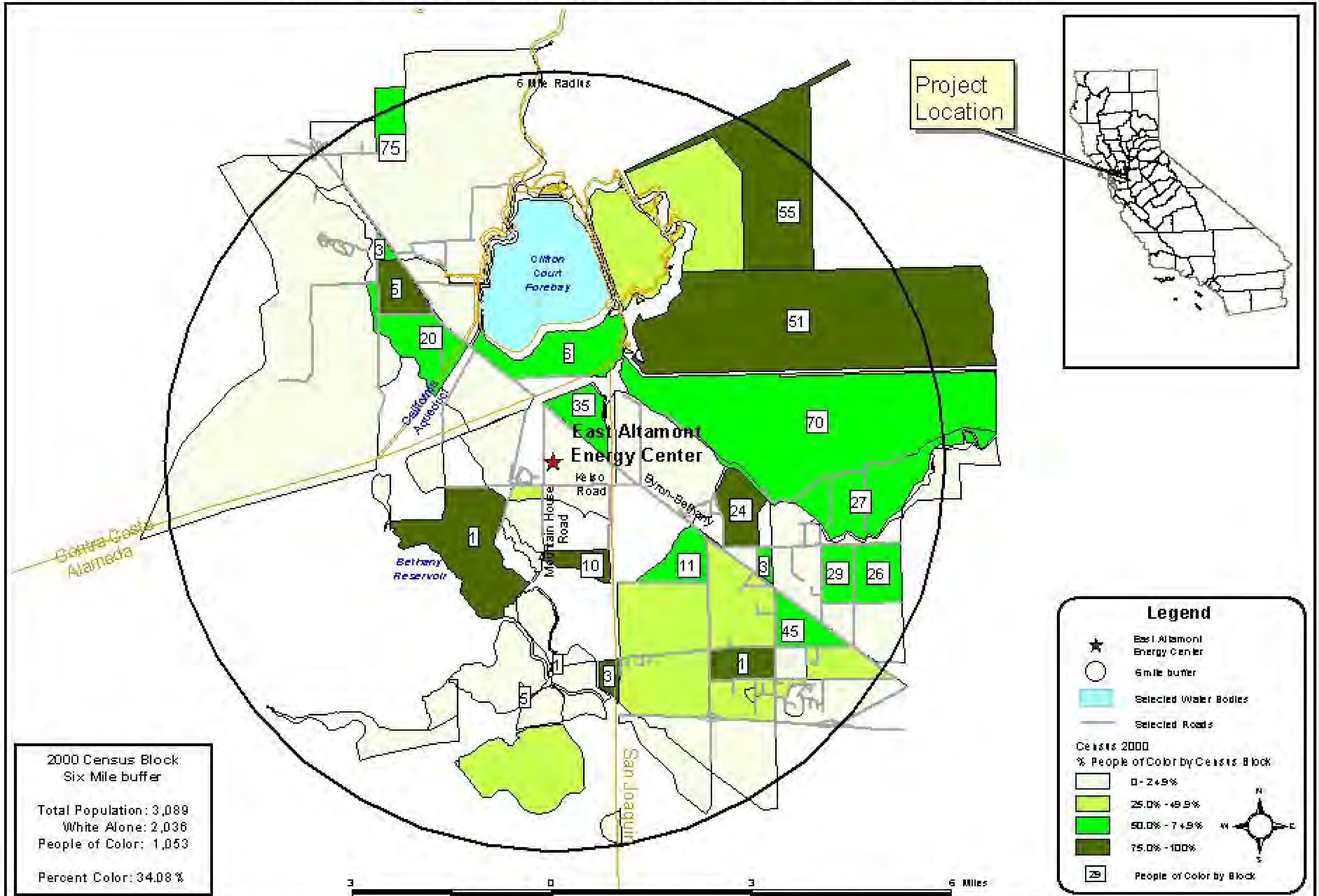
East Altamont Energy Center - Noise Monitoring Locations



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, SEPTEMBER 2002
SOURCE: EAEC

SOCIOECONOMICS - FIGURE 1

East Altamont Energy Center - Census 2000 Percentage People of Color by Census Block - Six Mile Buffer

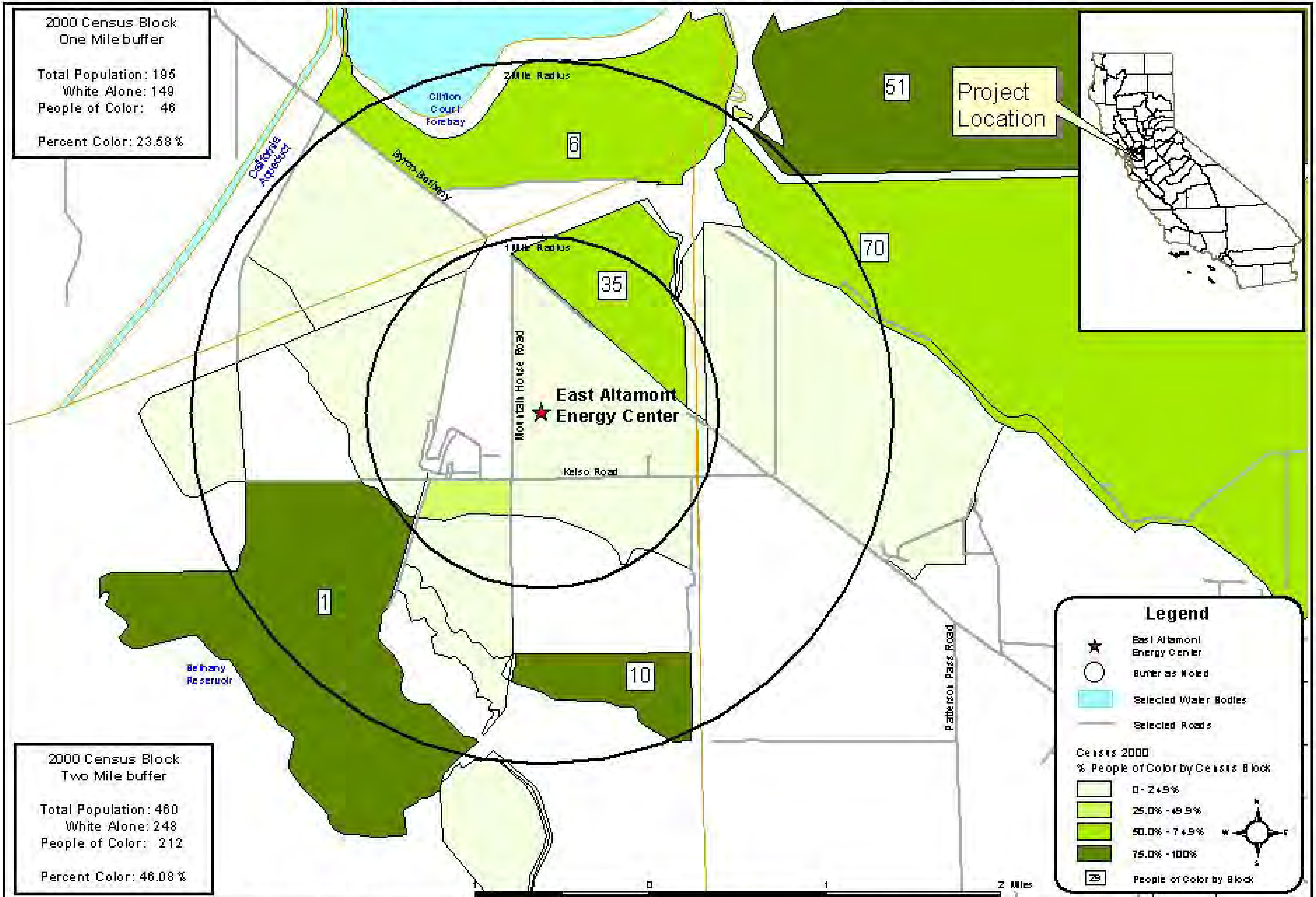


CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING & ENVIRONMENTAL PROTECTION DIVISION, SEPTEMBER 2002

SOURCE: California Energy Commission Statewide Transmission & Power Plant Maps 2001, Census 2000 PL 94-171 Data - Matrix PL2

SOCIOECONOMICS - FIGURE 2

East Altamont Energy Center - Census 2000 Percentage People of Color by Census Block - One and Two Mile Buffer

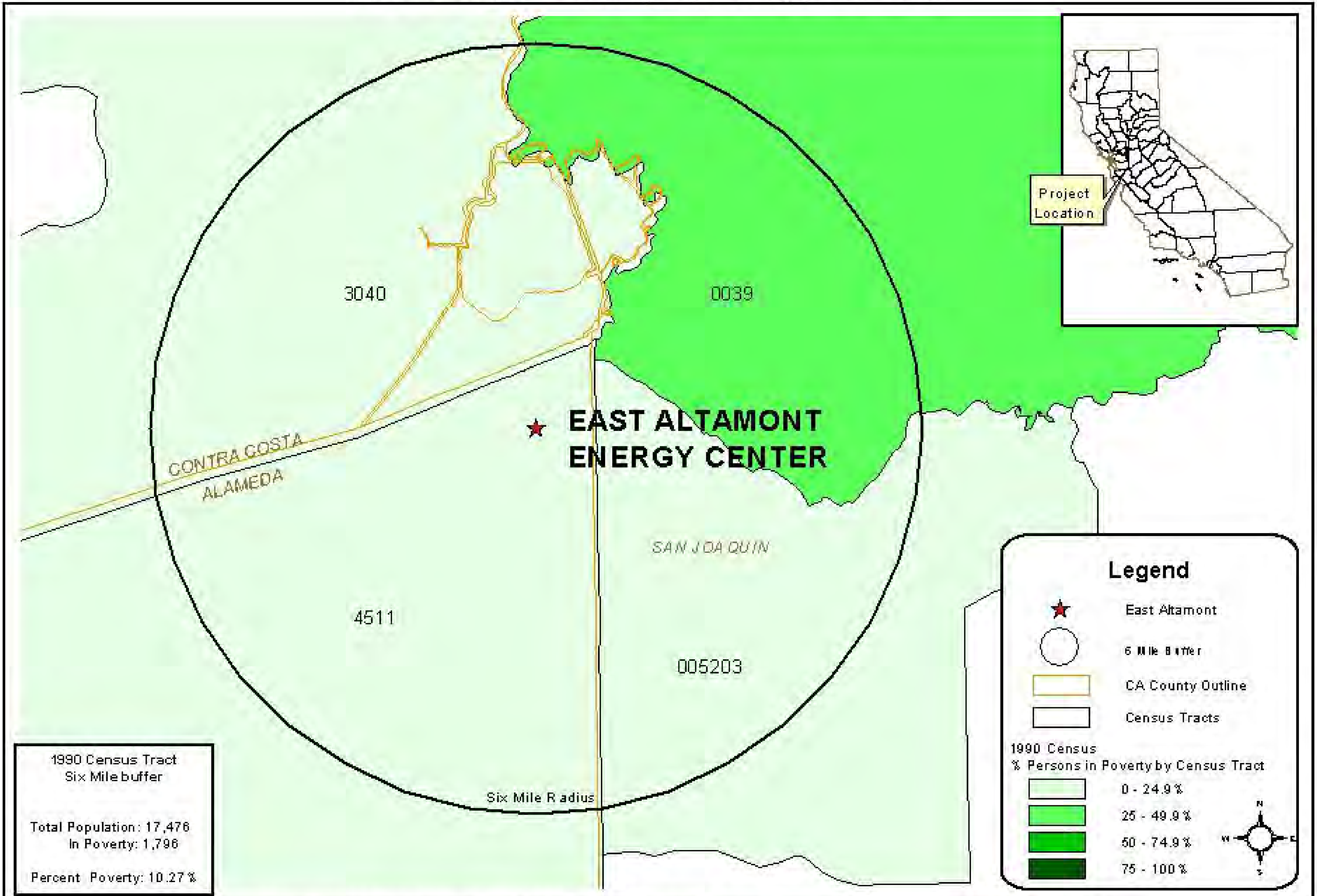


CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING & ENVIRONMENTAL PROTECTION DIVISION, SEPTEMBER 2002

SOURCE: California Energy Commission Statewide Transmission & Power Plant Maps 2001, Census 2000 PL 94-171 Data - Matrix PL2

SOCIOECONOMICS - FIGURE 3

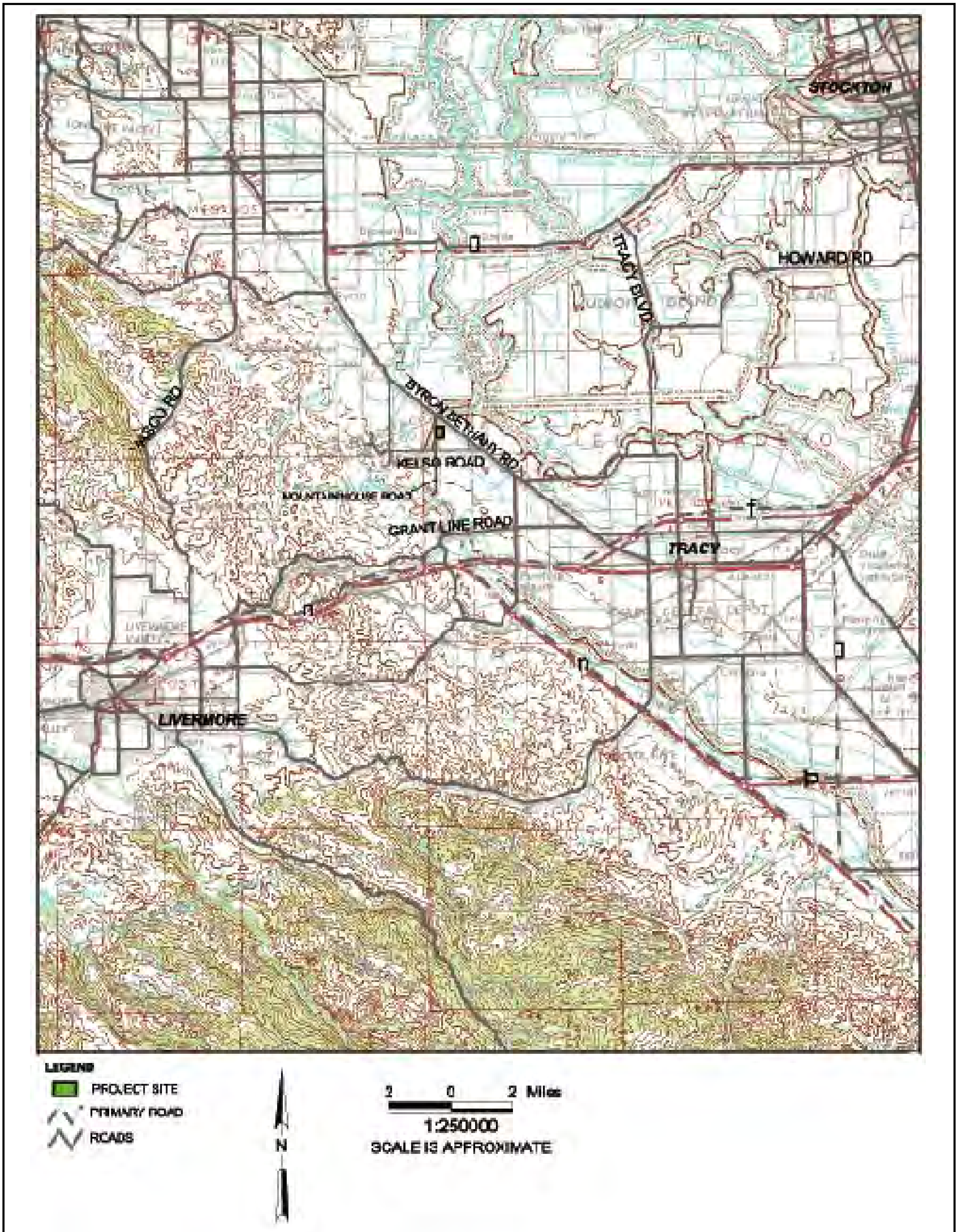
East Altamont Energy Center - Percentage People in Poverty by Census Tract 1990



CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING & ENVIRONMENTAL PROTECTION DIVISION, SEPTEMBER 2002

SOURCE: California Energy Commission Statewide Transmission & Power Plant Maps 2001, 1990 Census TIGER Data

TRAFFIC & TRANSPORTATION - Figure 1
East Altamont Energy Center- Local Roadways in Vicinity of East Altamont Energy Center



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, SEPTEMBER 2002
SOURCE: AFC 2001, Fig. 8.10-1

VISIBLE PLUMES - FIGURE 1

KOP 1 - Existing view to the west from approximately 0.75 mile southeast on Byron Bethany Road.

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, SEPTEMBER 2002

SOURCE: EAEC 2001 n, Data Response 1

VISIBLE PLUMES - FIGURE 2

KOP 1 - Visual simulation of project plumes as viewed from approximately 0.75 mile southeast on Byron Bethany Road.

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, SEPTEMBER 2002

SOURCE: Plume Simulation from Bill Kanemoto

VISIBLE PLUMES - FIGURE 3

KOP 2 - Existing view northwest from approximately two miles southeast on Byron Bethany Road.

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, SEPTEMBER 2002

SOURCE: Photo taken by Commission Staff - August 20th, 2002

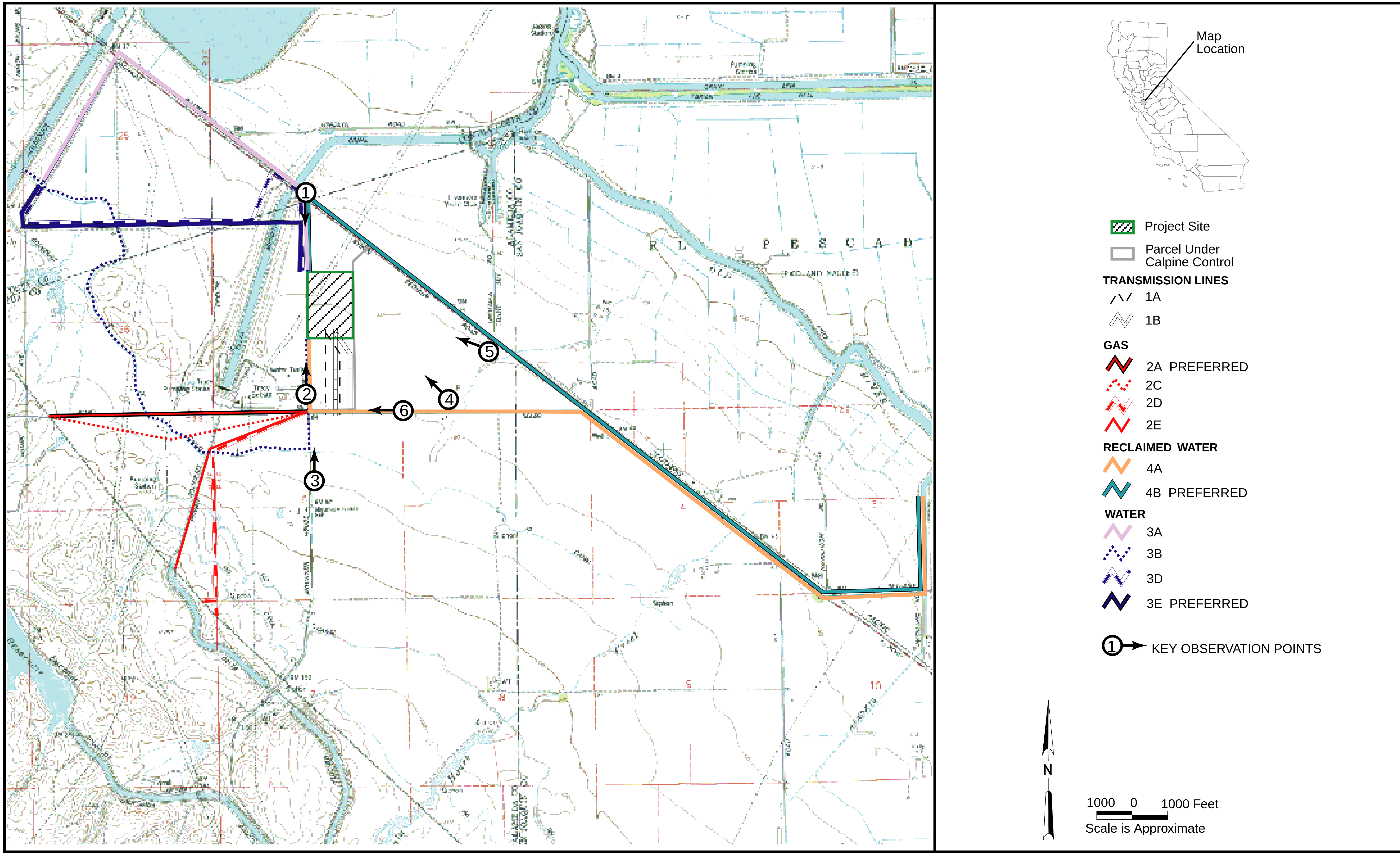
VISIBLE PLUMES - FIGURE 4

KOP 2 - Visual simulation of project plumes as viewed from approximately two miles southeast on Byron Bethany Road.

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, SEPTEMBER 2002

SOURCE: Photo taken by Commission Staff - August 20th, 2002 - Plume Simulation from Bill Kanemoto

VISUAL RESOURCES - FIGURE 1
Location of Key Observation Points



CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, SEPTEMBER 2002
SOURCE: EAEC 2001a, Figures 2.1-1 and 8.11-1

VISUAL RESOURCES - FIGURE 2A

KOP 1 - Existing view to the south from the intersection of Byron Bethany Road and Mountain House Road.

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, SEPTEMBER 2002

SOURCE: EAEC 2001 n, Data Response 1

VISUAL RESOURCES - FIGURE 2B

KOP 1 - Visual simulation of the proposed project at the start of project operation, as viewed from the intersection of Byron Bethany Road and Mountain House Road.

SOURCE: EAEC 2001 n, Data Response 2a

VISUAL RESOURCES - FIGURE 2C

KOP 1 - Visual simulation of the proposed project at 20 years, as viewed from the intersection of Byron Bethany Road and Mountain House Road.

SOURCE: EAEC 2001 n, Data Response 2c

VISUAL RESOURCES - FIGURE 3A

KOP 2 - Existing view to the north from northbound Mountain House Road, just north of Kelso Road.

SOURCE: EAEC 2001 n, Data Response 1

VISUAL RESOURCES - FIGURE 3B

KOP 2 - Visual simulation of the proposed project at the start of project operation, as viewed from Mountain House Road, just north of Kelso Road.

SOURCE: EAEC 2001 n, Data Response 2a

VISUAL RESOURCES - FIGURE 3C
KOP 2 - Visual simulation of the proposed project at 20 years, as viewed from Mountain House Road, just north of Kelso Road.

SOURCE: EAEC 2001 n, Data Response 2c

VISUAL RESOURCES - FIGURE 4A

KOP 3 - Existing view to the north from Mountain House Road, at Mountain House School.

SOURCE: EAEC 2001 n, Data Response 1

VISUAL RESOURCES - FIGURE 4B

KOP 3 - Visual simulation of the proposed project at the start of project operation, as viewed from Mountain House Road, at Mountain House School.

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, SEPTEMBER 2002

SOURCE: EAEC 2001 n, Data Response 2a

VISUAL RESOURCES - FIGURE 4C

KOP 3 - Visual simulation of the proposed project at 20 years, as viewed from Mountain House Road, at Mountain House School.

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, SEPTEMBER 2002

SOURCE: EAEC 2001 n, Data Response 2c

VISUAL RESOURCES - FIGURE 5A

KOP 4 - Existing view to the northwest from Kelso Road, approximately 0.55 mile southeast of the project site.

SOURCE: EAEC 2001 n, Data Response 1

VISUAL RESOURCES - FIGURE 5B

KOP 4 - Visual simulation of the proposed project at the start of project operation, as viewed from Kelso Road, approximately 0.55 mile southeast of the project site.

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, SEPTEMBER 2002

SOURCE: EAEC 2001 n, Data Response 2a

VISUAL RESOURCES - FIGURE 5C

KOP 4 - Visual simulation of the proposed project at 20 years, as viewed from Kelso Road, approximately 0.55 mile southeast of the project site.

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, SEPTEMBER 2002

SOURCE: EAEC 2001 n, Data Response 2c

VISUAL RESOURCES - FIGURE 6A

KOP 5 - Existing view to the west from the intersection of Byron Bethany Road and Lindeman Road.

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, SEPTEMBER 2002

SOURCE: EAEC 2001 n, Data Response 1

VISUAL RESOURCES - FIGURE 6B

KOP 5 - Visual simulation of the proposed project at the start of project operation, as viewed from the intersection of Byron Bethany Road and Lindeman Road.

CALIFORNIA ENERGY COMMISSION, SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION, SEPTEMBER 2002

SOURCE: EAEC 2001 n, Data Response 2a

VISUAL RESOURCES - FIGURE 6C

KOP 5 - Visual simulation of the proposed project at 20 years, as viewed from the intersection of Byron Bethany Road and Lindeman Road.

SOURCE: EAEC 2001 n, Data Response 2c

VISUAL RESOURCES - FIGURE 7A

KOP 6 - Existing view to the west from Kelso Road, approximately 0.45 mile east of Mountain House Road.

SOURCE: EAEC 2001 n, Data Response 1

VISUAL RESOURCES - FIGURE 7B

KOP 6 - Visual simulation of the project at the start of operation, as viewed from Kelso Road, approximately 0.45 mile east of Mountain House Road.

SOURCE: EAEC 2001 n, Data Response 2a

VISUAL RESOURCES - FIGURE 8

KOP 5 - Visual simulation of project plumes under clear conditions, as viewed from the intersection of Byron Bethany Road and Lindeman Road.

SOURCE: Plume Simulation from Bill Kanamoto for clear conditions

VISUAL RESOURCES - FIGURE 9

KOP 5 - Visual simulation of project plumes under low overcast conditions, as viewed from the intersection of Byron Bethany Road and Lindeman Road.

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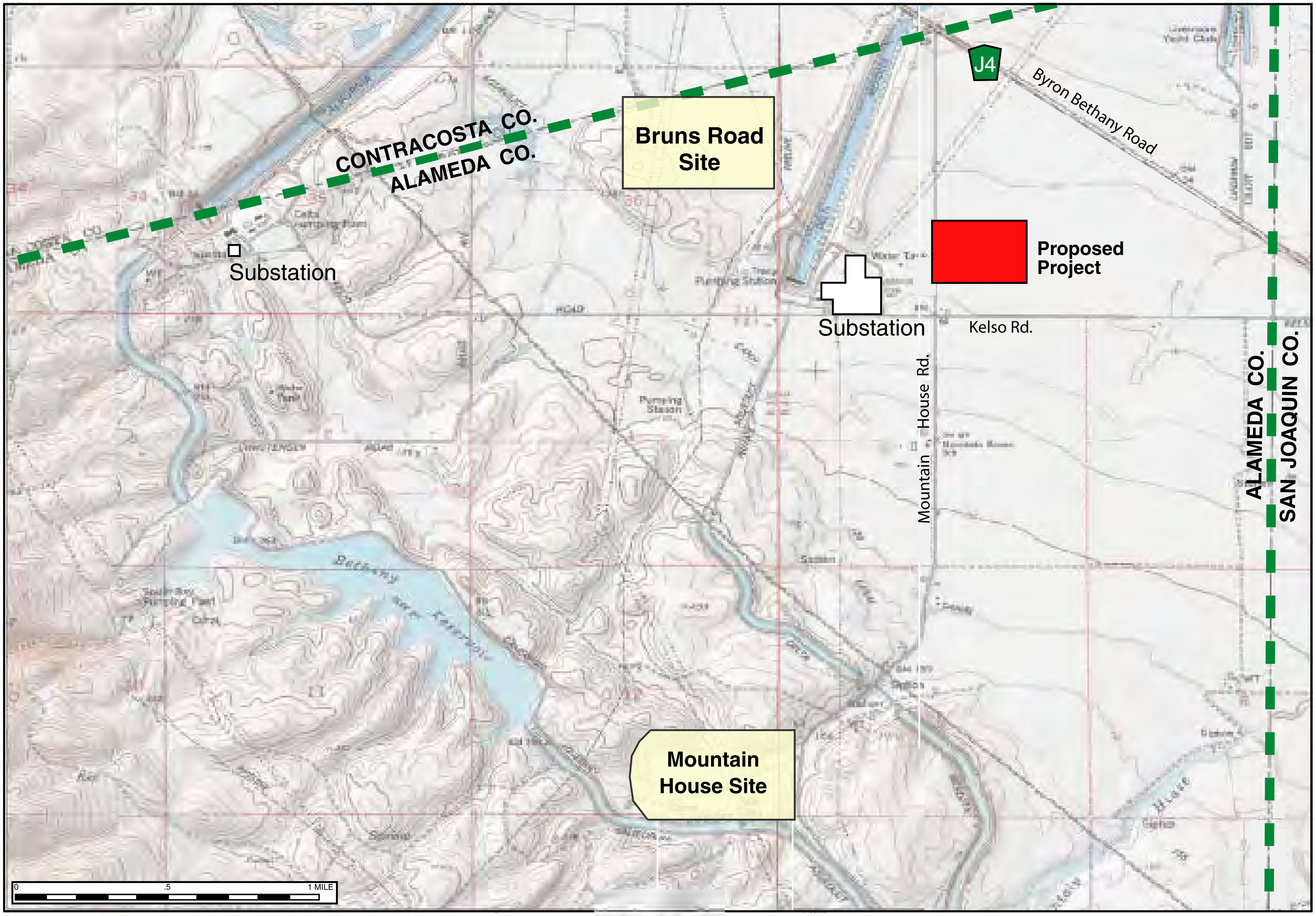
SOURCE: Plume Simulation from Bill Kanamoto for low overcast conditions

ALTERNATIVES - Figure 1
East Altamont Energy Center - Bruns and Mountain House and Alternative Sites



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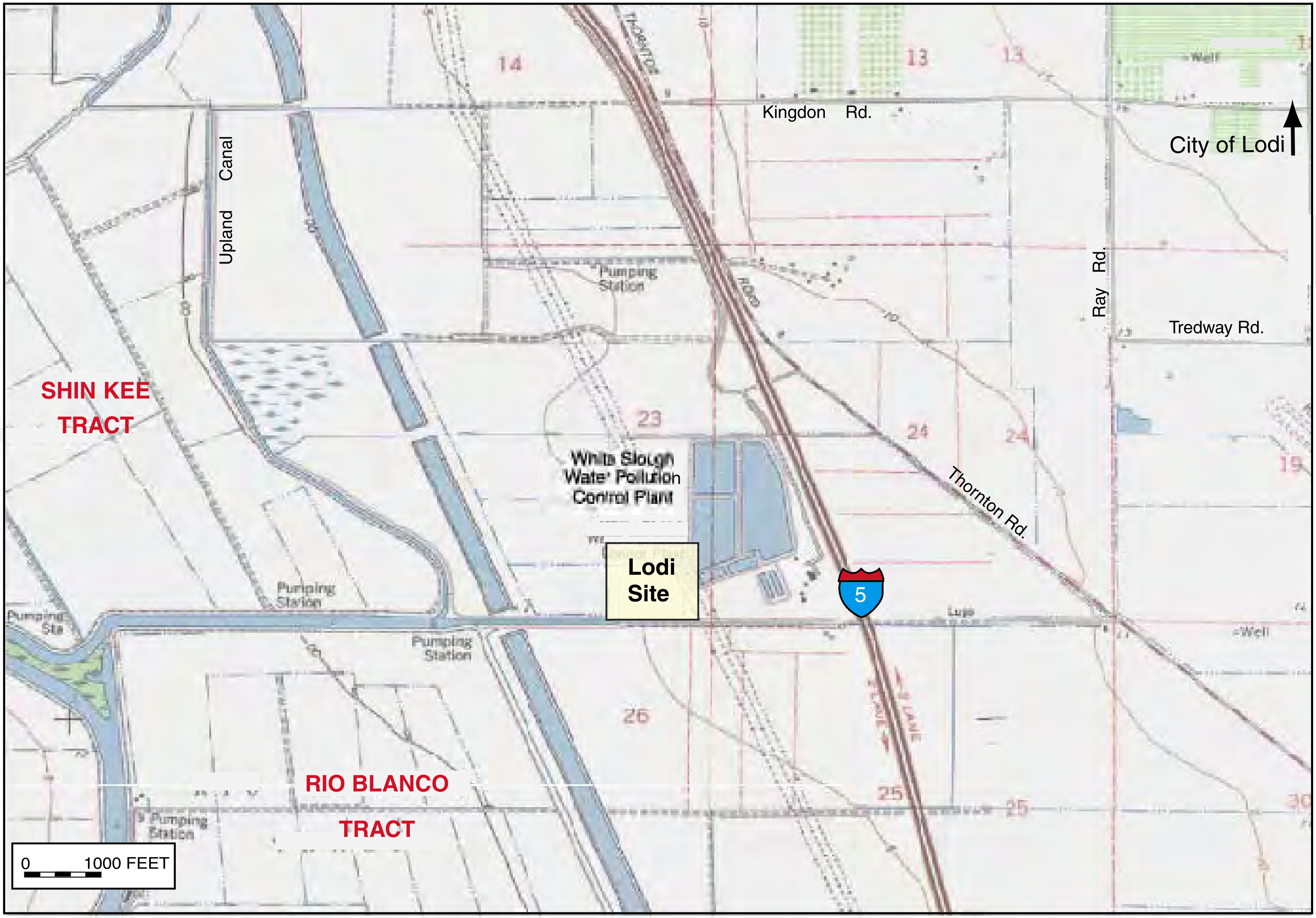
SOURCE: USGS

ALTERNATIVES - Figure 2
East Altamont Energy Center - Lodi Alternative Site



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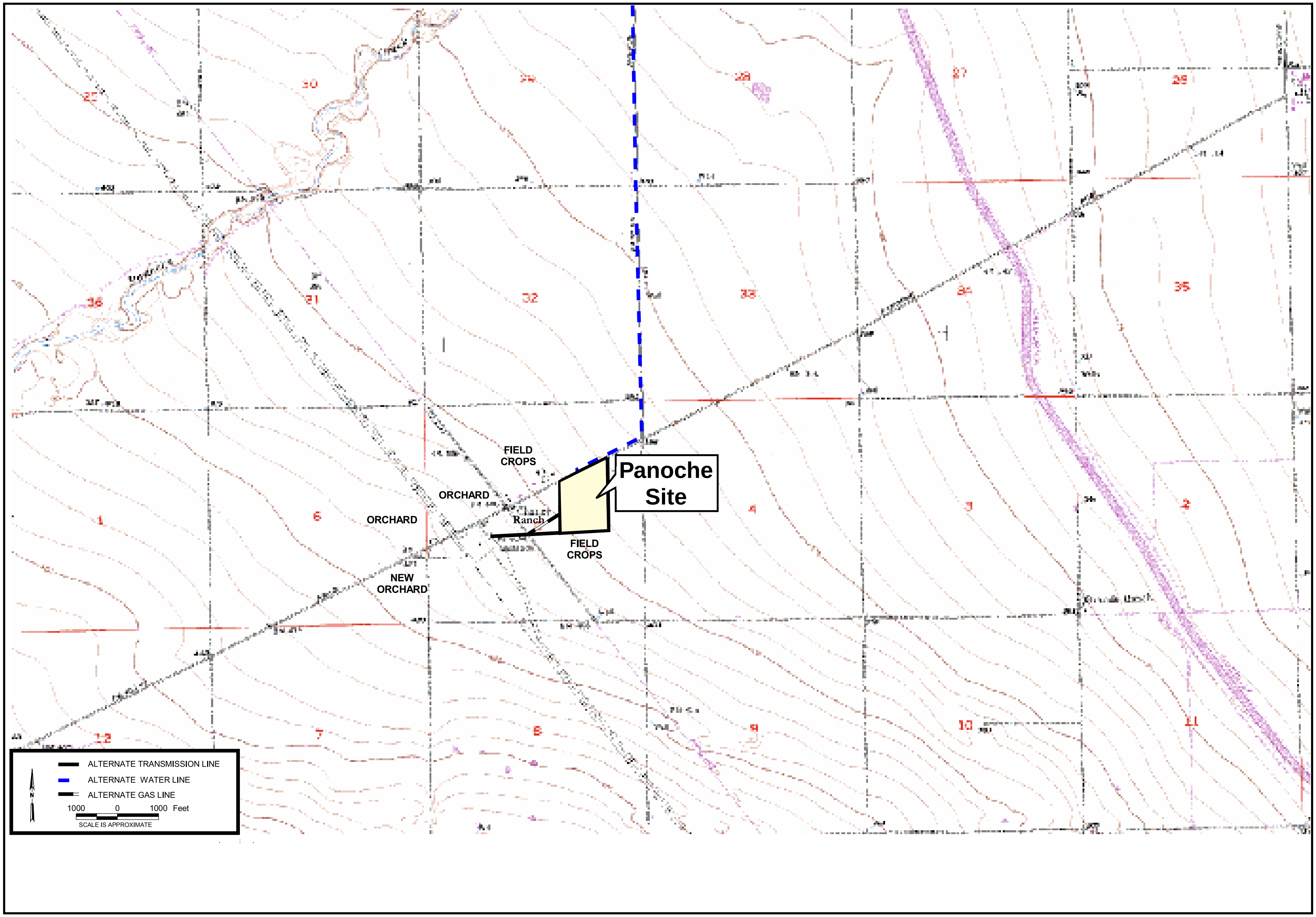
SOURCE: USGS

ALTERNATIVES - Figure 3
East Altamont Energy Center - Panoche Alternative Site



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SOURCE: USGS